Final decision

Queensland

distribution determination
2010–11 to 2014–15

May 2010

Contents

Shortened forms

AER	Australian Energy Regulator
capex	capital expenditure
CPI	consumer price index
current regulatory control period	1 July 2005 to 30 June 2010
DNSP	distribution network service provider
draft decision	AER, *Draft decision, Queensland draft distribution determination 2010–11 to 2014–15*, 25 November 2009
draft distribution determinations	AER, *Draft distribution determination Energex, 1 July 2010 – 30 June 2015*, 25 November 2009; and AER, *Draft distribution determination Ergon Energy, 1 July 2010 – 30 June 2015*, 25 November 2009.
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
next regulatory control period	1 July 2010 to 30 June 2015
opex	operating expenditure
PB	Parsons Brinckerhoff Strategic Consulting
QCA	Queensland Competition Authority
the Qld DNSPs	Energex and Ergon Energy

Overview

Under the National Electricity Law (NEL) and the NER, the Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution services provided by distribution network service providers (DNSPs) in the national electricity market (NEM).

This is the first time that electricity distribution determinations have been made by the AER on the revenue control regimes to apply to Energex and Ergon Energy (the Qld DNSPs). The previous determination that applied to the Qld DNSPs for the period 2005–10 was made by the Queensland Competition Authority (QCA).

In making its decision and distribution determinations, the AER has taken into account the revised regulatory proposals submitted by the Qld DNSPs, submissions from interest parties, further advice from consultants and updated economic information and forecasts.

The AER's determinations for Energex and Ergon Energy provide for distribution charges to increase over the next five years. This increase in network charges will flow through retail electricity prices to residential customers. A price rise of 9 per cent in 2010–11 will result from higher network charges. In the remaining four years of the regulatory control period, retail prices are expected to rise by around 2.3 per cent. Further explanation of the AER's decision and the context in which it was made is provided below and in greater detail through the chapters of this decision.

Arrangements for establishing street lighting charges and charges for quoted and fee based services are also provided for in this decision. Quoted and fee based services are those provided in response to a specific request from a customer often by property developers or in reference to new developments. They include such services as temporary connections, supply enhancement, emergency recoverable works and de-energisation and re-energisation.

Key outcomes and considerations

Network charges

The AER has established the annual revenue requirements for the Qld DNSPs based on the AER's approved capital and operating expenditure allowances. Energex's total revenue for the next regulatory control period is $7011 million (nominal). Ergon Energy's total revenue for the period is $6554 million (nominal).

Energex's allowed revenues will increase in nominal terms by 21.2 per cent in 2010–11 compared to the preceding year. Ergon Energy's allowed revenues will increase in nominal terms by 32.9 per cent compared to the preceding year. For the remaining four years of the regulatory period, Energex and Ergon Energy's revenues will increase in nominal terms by 10.6 and 7.7 per cent per annum respectively. Network prices will increase on average by a lower rate reflecting the partially offsetting effect of higher energy consumption.

In part the significant increase in revenues in 2010–11 is explained by developments in the preceding 5 years. Both Energex and Ergon Energy's capital expenditures in the

2005–10 regulatory period exceeded their allowances. The increase in Ergon Energy's revenues would be about a third lower if its capex during the current regulatory period (which is included in the regulatory asset base from 1 July 2010) had not exceeded the QCA's allowance, while the increase in Energex's revenues would be about 15 per cent lower. Also, if the WACC parameters had remained the same as those applied in the current regulatory period, the increase in Energex's revenues in 2010–11 would be about two thirds lower, while the increase for Ergon Energy would be over a third lower.

Based on a typical residential customer's annual retail electricity charges of $1400 in 2009–10, that customer can expect to pay just over 9.2 per cent, or around $129 in total, more in these charges in 2010–11. Beyond 2010–11, further retail price rises for residential customers will be around 2.3 per cent or $35 each year. It should be noted that factors other than distribution charges will cause retail prices to vary including, for example, factors influencing wholesale electricity prices.

The specific circumstances faced by the Qld DNSPs which justify these price increases are discussed in this decision.

Capital and operating expenditure

Since the time of the draft decision in November 2009 the outlook for economic activity in Queensland has become more positive. There is now the prospect of stronger economic activity driven by the minerals sector and domestic sector activity may not be as severely impacted by the Global Financial Crisis as considered likely in late 2009.

The AER reviewed the demand forecasts included in the Qld DNSPs' revised regulatory proposals and has determined a modest upward revision is appropriate for the growth in maximum demand. Overall maximum demand for energy in Queensland is expected to grow at around twice the rate of growth of customer numbers over the period 2010–2015. Energy consumption will grow at a slower rate than maximum demand but still faster than customer numbers. These factors underpin the need for ongoing expansion to the Queensland electricity distribution networks.

The AER has reviewed the revised capital expenditure programs of the Qld DNSPs and has maintained its position from the draft decision that results in demand related capital expenditure of around 20 per cent less than that proposed by the Qld DNSPs due to overstated demand forecasts. This accounts for the largest element of the AER's reductions to the revised capital expenditure allowances.

PB's analysis of the Qld DNSPs' revised regulatory proposals and supporting information confirmed its previous advice to the AER with some exceptions. With respect to Energex, PB recommended that certain property and building expenditure proposals it had previously found not to be justified should be accepted by the AER based on additional information provided by Energex. Based on its own analysis and the advice of its consultants, the AER has accepted these adjustments should be made.

With respect to Ergon Energy, the AER considered the revised demand related capital expenditure program and sought to reconcile it using more up-to-date planning documentation provided by Ergon Energy. Based on additional information and advice from PB, the AER has reduced Ergon Energy's forecast capital expenditure from that in the revised proposal to reflect more up to date forecast capex requirements and a more realistic demand forecast. The AER has also reduced proposed capital expenditure on asset replacement and major property projects where it found that these expenditures were not efficient.

After considering the Qld DNSPs' revised regulatory proposals against the capital expenditure criteria under chapter 6 of the NER, the AER concluded that Energex and Ergon Energy's proposed capital expenditure is $321 million and $1452 million respectively higher than an efficient level. The AER's determination results in a 4.8 per cent and a 20.7 per cent reduction in the capital expenditure proposed by Energex and Ergon Energy respectively.

The AER's assessment of the revised regulatory proposals is that Ergon Energy's proposed operating expenditure for the next regulatory control period is $122 million higher than an efficient amount. The AER's decision results in a 5.9 per cent reduction to Ergon Energy's proposed operating expenditure.

The AER did not accept certain operating expenditures proposed by Energex. Overall, however, the AER's decision results in an increase of 1.6 per cent for Energex on the proposed operating expenditure contained in its revised regulatory proposal. This increase largely results from the application of the AER's revised cost escalators to Energex's revised regulatory proposal.

Since the draft decision the AER has updated the materials and labour cost escalators used to forecast capital and operating expenditures to reflect current economic conditions. This analysis determined that the escalators proposed by Ergon Energy in its revised regulatory proposal and by Energex in its subsequent February submission were likely to overstate future costs. The AER has applied its own real materials and labour cost escalators based on recent forecasts.

Regulatory rate of return

The AER determined a nominal vanilla WACC of 9.72 per cent for the Qld DNSPs. This is approximately 30 basis points lower than in the draft decision. The revised WACC is based on more recent financial market conditions which have seen an easing of debt risk premiums. Current debt risk premiums however are still well above the historic average.

Implementation of new incentive schemes

This decision implements three new incentive schemes that will apply to the Qld DNSPs over the next regulatory control period:

- the service target performance incentive scheme – which encourages network service providers to maintain or improve their service performance in terms of the number and incidence of outages on their network. The scheme includes benefits or penalties for over or under performance.

- the efficiency benefit sharing scheme – which is designed to provide a fair sharing of operating cost efficiency benefits and losses between network service providers and network users. The scheme includes benefits or penalties for over or under performance.

- the demand management incentive scheme – which is designed to provide incentives for network service providers to pursue and implement innovative non-network solutions to address growing demand on their networks. This scheme provides an incentive for DNSPs to invest in non-network solutions that could in the future be implemented more generally resulting in savings to electricity users.

Review process

The AER's determination for the Qld DNSPs for the 2010–2015 regulatory control period has been made under the relevant provisions of the NER and NEL. The AER was also required to consider a number of transitional requirements for Queensland that are set out in chapter 11 of the NER.

The AER released its draft decision and draft determinations for the Qld DNSPs in November 2009. The Qld DNSPs submitted their revised regulatory proposals in January 2010 indicating where they did not agree with the draft decision.

In this decision the AER specifically addresses those aspects of the draft decision which have not been accepted in the Qld DNSPs' revised regulatory proposal or in a submission by another party. Where an aspect of the draft decision was not addressed in a revised regulatory proposal or submissions, then the determination made in the draft decision is confirmed in this decision.

The AER's detailed examination of the Qld DNSPs' regulatory proposal and revised regulatory proposals was informed by advice from Parsons Brinckerhoff Strategic Consulting (PB). In addition to PB, the AER also engaged McLennan Magasanik Associates, a consultancy firm with considerable experience in energy demand forecasting, to review the Qld DNSPs' revised peak demand forecasts.

In making its decision, the AER assessed the Qld DNSPs' revised regulatory proposals to determine if they were in accordance with the requirements of the NER. The AER also considered the past performance of the Qld DNSPs and the effectiveness of their policies and procedures, both in terms of past performance and in the development of their regulatory proposal.

Summary

Introduction

The Queensland Competition Authority (QCA) made the current regulatory determinations for Energex and Ergon Energy (the Qld DNSPs) for a five year period from 1 July 2005 to 30 June 2010 (the current regulatory control period). These DNSPs own and operate the electricity distribution networks in Queensland.

The AER assumes responsibility for regulating electricity distribution services provided by the Qld DNSPs from 1 July 2010. The distribution determinations for the period 1 July 2010 to 30 June 2015 (the next regulatory control period) are the first for the Qld DNSPs to be conducted by the AER under the National Electricity Rules (NER).

On 30 June 2009 the Qld DNSPs submitted their regulatory proposals for the next regulatory control period to the AER. On 17 July 2009 the AER published the proposals and its proposed negotiated distribution service criteria (NDSC) for the Qld DNSPs. Interested parties were invited to make submissions on the proposals and 11 submissions were received. The Qld DNSPs presented their regulatory proposals at a public forum held in Brisbane on 3 August 2009.

The AER engaged the following consultants to assist in the assessment of the regulatory proposals and revised regulatory proposals:

- Parsons Brinckerhoff Strategic Consulting (PB)
- McLennan Magasanik Associates (MMA)
- Energy and Management Services (EMS)
- Access Economics
- McGrathNicol Corporate Advisory (McGrathNicol)
- Professor Michael McKenzie and Associate Professor Graham Partington (University of Sydney)
- Associate Professor John Handley (University of Melbourne).

This decision should be read in conjunction with the draft decision and consultants' reports which are available on the AER's website.

The key decisions addressed in this decision for the Qld DNSPs are:

- classification of services
- specification of the control mechanisms and methodologies for demonstrating compliance with the control mechanism
- the opening regulatory asset base (RAB) values

- the AER's assessment of forecast capital expenditure (capex)
- the AER's assessment of forecast operating expenditure (opex)
- an estimate of the efficient benchmark weighted average cost of capital (WACC)
- the annual revenue requirement for each year of the next regulatory control period
- the negotiated distribution service criteria (NDSC) that will apply to the Qld DNSPs
- the schemes to provide incentives to the Qld DNSPs to improve efficiency, maintain service standards and manage increasing demand.

The AER's consideration of each of these components is summarised below. Further detail is provided in the relevant chapters and appendices of this decision.

Regulatory requirements

National Electricity Law

The National Electricity Law (NEL) sets out the functions and powers of the AER, including its role as the economic regulator of utilities operating in the national electricity market (NEM). Section 16 of the NEL states that when performing or exercising a regulatory function or power, the AER must do so in a manner that will or is likely to contribute to the achievement of the national electricity objective.

The national electricity objective is:

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

National Electricity Rules

Chapter 6 of the NER sets out provisions the AER must apply in exercising its regulatory functions and powers for electricity distribution networks. In particular, the AER must make a distribution determination for each Qld DNSP that includes a:

- building block determination in respect of standard control services
- determination in respect of alternative control services
- determination specifying requirements relating to the negotiating framework
- determination specifying the NDSC.

The distribution determination is predicated on constituent decisions to be made by the AER, specified in clause 6.12.1 of the NER. The NER requires the AER to:

- specify the classification of services that the AER is to apply
- specify the negotiating framework and NDSC to apply to the DNSP
- assess the DNSP's control mechanism for standard control services
- set out the methodology for establishing the opening RAB
- assess the DNSP's demand forecasts and cost inputs to achieve the capex and opex objectives
- assess whether the forecast capex and opex proposed by a DNSP reflect the efficient costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the capex or opex objectives
- set out the methodology for calculating the estimated corporate income tax
- set out the methodology for calculating depreciation on the assets to be included in the RAB and assess whether or not to approve the depreciation schedules submitted by a DNSP
- set out the methodology for calculating the cost of capital
- develop and publish a service target performance incentive scheme (STPIS), efficiency benefit sharing scheme (EBSS) and demand management incentive scheme (DMIS)
- specify additional pass through events
- specify the DNSP's annual revenue requirement for each year of the regulatory control period and set the X factor for each year of the regulatory control period
- set out the form of control the AER to apply to alternative control services
- set out how compliance with control mechanisms is to be demonstrated by the DNSP.

Classification of services

AER draft decision

The AER applied the service classifications set out in the framework and approach. The AER's procedures for the Qld DNSPs to assign and reassign customers to tariff classes were set out in appendix B of the draft decision.

Revised regulatory proposals

The Qld DNSPs stated that their respective regulatory proposals were consistent with the classification of services specified in the framework and approach.

Energex accepted the AER's procedure for assigning and reassigning customers to tariff classes set out in the draft decision. Ergon Energy did not accept the AER's draft decision and raised a number of matters for consideration.

AER decision

The AER confirms the service classifications set out in the framework and approach. The distribution service classifications are set out in appendix A of this decision.

The AER clarified the matters raised by Ergon Energy and confirms its draft decision regarding the procedures for Qld DNSPs to assign and reassign customers to tariff classes. The AER considers that the direct notification obligation placed on a DNSP to inform its customers of a tariff class assignment or reassignment decision is consistent with achieving a nationally consistent procedure. The AER's procedure for the Qld DNSPs to assign and reassign customers to tariff classes is set out in appendix B of this decision.

Arrangements for negotiation

AER draft decision

The AER did not apply negotiating frameworks to the Qld DNSPs for the next regulatory control period, as neither had any services classified as negotiated distribution services. The AER published its NDSC in appendix C of the draft decision.

AER decision

The NDSC to apply to the Qld DNSPs for the next regulatory control period are set out in appendix C of this decision.

Control mechanisms for standard control services

AER draft decision

The AER accepted the Qld DNSPs' proposals to apply a revenue cap form of control to their standard control services for the next regulatory control period.

The AER required the Qld DNSPs' annual pricing proposals to include proposed tariffs and charging parameters which result in expected revenues consistent with the maximum allowance revenue (MAR) formula plus any adjustment needed to set the balance of their distribution use of system (DUOS) unders and overs account to zero (or the agreed tolerance level).

The AER also stated that in their annual pricing proposals, the Qld DNSPs must demonstrate that their proposed DUOS prices for the next year will comply with the side constraints formula for each tariff class. Ergon Energy must also demonstrate compliance with the individual side constraints for a small group of customers not yet paying cost reflective prices.

Revised regulatory proposals

Energex

Energex resubmitted its proposal for a capital contribution bank. It provided confidential information concerning the scope for significant differences between forecast and actual capital contributions over the next regulatory control period.

Ergon Energy

Ergon Energy accepted the control mechanism for standard control services, however, it sought clarification from the AER on the:

- application of the DUOS unders and overs account
- inflation rate to be applied to the revenue cap
- definitions and terminology used for the MAR and side constraints formulas
- nature and application of the ring–fencing arrangements and compliance reporting
- treatment of feed–in tariffs and unfunded shared network events.

AER decision

The AER rejects Ergon Energy's proposal regarding the treatment of feed–in tariffs and unfunded shared network events in the control mechanism. The AER confirms the application of the QCA's ring–fencing and compliance reporting requirements to the next regulatory control period.

The MAR formula has been amended from that contained in the draft decision to clarify the issues raised by the Qld DNSPs in their revised regulatory proposals and submissions. The DUOS and transmission use of system (TUOS) unders and overs accounts (appendices D and E) have also been revised for consistency and clarity.

The MAR is determined annually by adding to, or subtracting from, the allowed revenue (AR) any STPIS revenue increment (or decrement), any unders/overs adjustments related to capital contributions, certain transitional adjustments and any approved pass through amounts.

With the exception of the first year of the next regulatory control period, the Qld DNSPs will be required to demonstrate in their annual pricing proposals that their proposed DUOS prices comply with the side constraints formula for each tariff class, specified in this decision.

Opening regulatory asset base

AER draft decision

Energex

The RAB roll forward calculations for Energex resulted in an opening RAB of $7887 million for standard control services as at 1 July 2010. The decrease in opening RAB reflected the use of a different inflation rate from that used by Energex as well as adjustments for actual capex differences, and exclusion of alternative control assets from the RAB.

Ergon Energy

The RAB roll forward calculations for Ergon Energy resulted in an opening RAB of $7105 million as at 1 July 2010. The AER determined opening RAB was higher than that proposed by Ergon Energy due to the use of a different inflation rate than that proposed by Ergon Energy.

Revised regulatory proposals

Energex

Energex proposed a revised opening RAB of $7841.5 million as at 1 July 2010, $46.0 million less than allowed in the draft decision.

Energex maintained the same approach to determining its opening RAB as in the draft decision. The only change it made to the roll forward model (RFM) was to update capex forecasts for 2008–09 to actuals.

Energex accepted the draft decision to determine its opening RAB for the 2015–20 regulatory control period using actual depreciation.

Ergon Energy

Ergon Energy proposed a revised opening RAB of $7174.0 million as at 1 July 2010, $68.6 million more than allowed in the draft decision.

Ergon Energy maintained the same approach to determining its opening RAB as in the draft decision. It also accepted the draft decision that the roll forward of its asset base over the current regulatory control period should use CPI based on the year to March.

However, Ergon Energy adjusted the forecast CPI figures for the current regulatory control period in its RFM. It also updated its capex forecasts for 2008–09 to actuals and provided revised capex forecasts for 2009–10.

Ergon Energy accepted the draft decision to determine its opening RAB for the 2015–20 regulatory control period using actual depreciation.

AER decision

Energex

The RAB roll forward calculations for Energex are set out in table 1 and provide for an opening RAB of $7867.3 million for standard control services for the next regulatory control period (as at 1 July 2010). The opening RAB for alternative control services is $96.8 million. This amount differs to that proposed by Energex in its revised regulatory proposal due to updating CPI for 2009–10.

Table 1: AER conclusion on Energex's opening RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10[a]
Opening RAB	4345.2	4996.7	5596.7	6248.6	6955.9
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	744.6	734.7	694.4	843.1	1041.5
Regulatory depreciation (adjusted for actual CPI)	–93.2	–134.7	–42.5	–135.7	–114.1
Closing RAB	4996.7	5596.7	6248.6	6955.9	7883.4
Difference between actual and forecast capex for 2004–05					53.1
Return on difference					27.7
Less: system assets moving from standard control services to alternative control services					–96.8
Opening RAB at 1 July 2010					7867.3

(a) Based on estimated net capex.

Ergon Energy

The RAB roll forward calculations for Ergon Energy are set out in table 2 and provide for an opening RAB of $7148.9 million for standard control services for the next regulatory control period (as at 1 July 2010).

Table 2: AER conclusion on Ergon Energy's opening RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10[a]
Opening RAB	4146.2	4662.4	5243.4	5858.1	6452.6
Actual net capex (adjusted for actual CPI and WACC)	622.1	720.2	654.5	737.0	819.5
Regulatory depreciation (adjusted for actual CPI)	–105.9	–139.3	–39.7	–142.4	–123.2
Closing RAB	4662.4	5243.4	5858.1	6452.6	7148.9
Opening RAB at 1 July 2010					7148.9

(a) Based on estimated net capex.

Demand forecasts

AER draft decision

The AER accepted Energex's forecasts of customer numbers and energy consumption. The AER considered the maximum demand forecasts proposed by Energex did not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives. The AER reduced Energex's forecast maximum demand to the levels shown in table 3.

Table 3: AER draft conclusion on Energex's maximum demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15[a]
Maximum demand (MW)	4864	5027	5228	5466	5684	4.0%
Customer numbers	1 363 138	1 389 033	1 417 664	1 448 548	1 480 294	2.1%
Energy consumption (GWh)	22 416	23 138	24 042	24 795	25 845	3.6%

(a) Average annual growth rate calculated based on 2010–11 to 2014–15 data.

Ergon Energy

The AER accepted Ergon Energy's forecasts of customer numbers. The AER considered the maximum demand and energy consumption forecasts proposed by Ergon Energy did not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives. The AER reduced Ergon Energy's forecast maximum demand to the levels shown in table 4. The AER required Ergon Energy to review its energy consumption forecasts before submitting its pricing proposal to the AER for approval in 2010.

Table 4: AER draft conclusions on Ergon Energy's maximum demand and customer number forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15[a]
Maximum demand (MW)	2693	2811	2928	3031	3121	3.8%
Customer numbers	684 469	695 242	706 204	717 356	728 706	1.6%

(a) Average annual growth rate calculated based on 2010–11 to 2014–15 data.

Revised regulatory proposals

Energex

Energex disagreed with the draft decision to adopt an alternative system maximum demand forecast. It accepted the draft decision that its proposed customer numbers and energy consumption forecasts provided a realistic expectation of demand forecast required to achieve the capex and opex objectives.

Ergon Energy

Ergon Energy disagreed with the draft decision not to accept its maximum demand forecast. Ergon Energy provided a revised maximum demand forecast based on updated bottom up and top down forecasts produced by itself and NIEIR respectively. Ergon Energy stated that it has reconciled its bottom up demand forecast with NIEIR's top down system demand forecast, which were both produced in December 2009. Ergon Energy advised that apart from the first year of the next regulatory control period, its revised forecast aligns closely with the original forecast contained in its regulatory proposal with differences in each year less than one per cent.

Ergon Energy accepted the draft decision regarding its proposed customer numbers but did not accept the draft decision on its proposed energy consumption forecast. It provided a revised energy consumption forecast identical to its original forecast.

AER decision

Energex

The AER considers that the revised system maximum demand forecasts proposed by Energex do not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the NER.

The AER considers that the customer numbers and energy consumption forecasts proposed by Energex provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives.

The AER's conclusions on Energex's maximum demand, energy consumption and customer number forecasts over the next regulatory control period are set out in table 5. The amounts determined by the AER have been amended from Energex's revised regulatory proposal only to the extent necessary to enable it to be approved in accordance with the NER.

Table 5: AER conclusions on Energex maximum demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 [a]
Maximum demand (MW)	4931	5089	5328	5555	5733	3.8%
Customer numbers	1 363 138	1 389 033	1 417 664	1 448 548	1 480 294	2.1%
Energy consumption (GWh)	22 416	23 138	24 042	24 795	25 845	3.6%

(a) Average annual growth rate calculated based on 2010–11 to 2014–15 data.

Ergon Energy

The AER considers that the revised system and spatial maximum demand forecasts proposed by Ergon Energy do not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the NER.

The AER considers that the customer number and energy consumption forecasts proposed by Ergon Energy provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the NER.

The AER's conclusions on Ergon Energy's maximum demand, energy consumption and customer number forecasts over the next regulatory control period are set out in table 6. The amounts determined by the AER have been amended from Ergon Energy's revised regulatory proposal only to the extent necessary to enable it to be approved in accordance with the NER.

Table 6: AER conclusions on Ergon Energy's maximum demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 [a]
Maximum demand (MW)	2778	2907	3017	3100	3171	3.4%
Customer numbers	684 469	695 242	706 204	717 356	728 706	1.6%
Energy consumption (GWh)	15 871	16 450	16 874	17 433	17 887	3.0%

(a) Average annual growth rate calculated based on 2010–11 to 2014–15 data.

Forecast capital expenditure

AER draft decision

Energex

The AER was not satisfied that Energex's forecast capex of $6466 million reasonably reflected the capex criteria. The AER was not satisfied that Energex's growth capex reflected a realistic expectation of demand, or that its proposed cost escalators reflected a realistic expectation of cost inputs. Further the AER considered that Energex's proposed non–system capex on major building projects had not been demonstrated to be prudent and efficient.

Following its review of Energex's capex proposal the AER made the following adjustments:

- $372 million reduction to total capex (related to cost escalators)
- $289 million reduction to growth capex
- $158 million reduction to non–system capex
- $7 million reduction in indirect costs associated with information, communications and telecommunications (ICT) services.

The AER was satisfied an estimate of $5718 million for Energex's forecast capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered this reduction was the minimum adjustment necessary to ensure Energex's capex forecast met the capex criteria.

Ergon Energy

The AER was not satisfied that Ergon Energy's forecast capex of $6033 million reasonably reflected the capex criteria. The AER did not consider Ergon Energy's proposed growth capex reflected a realistic expectation of the demand forecast required to achieve the capex objectives. The AER also considered that Ergon Energy's proposed asset replacement capex did not reflect efficient costs.

The AER also considered that Ergon Energy's proposed reliability and quality improvement capex, in particular the feeder improvement program, had not been demonstrated to be prudent and efficient. Further, the AER considered the expenditure associated with Ergon Energy's major building projects and the ICT systems change program had not been demonstrated to be prudent and efficient.

Following its review of Ergon Energy's capex proposal the AER made the following adjustments:

- $844 million reduction to growth capex
- $119 million reduction to asset replacement capex
- $35 million reduction to reliability and quality improvement capex

- $39 million reduction in shared costs associated with ICT services, sponsorship and community engagement
- $253 million reduction to non–system capex
- $82 million increase to total capex to account for errors in the application of input cost escalators.

The AER was satisfied an estimate of $5013 million for Ergon Energy's forecast capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered this reduction was the minimum adjustment necessary to ensure Ergon Energy's capex forecast met the capex criteria.

Revised regulatory proposals

Energex

Energex included a capex allowance of $6069 million ($2009–10) for the next regulatory control period. Energex subsequently submitted a revised approach to cost escalation, which increased its proposed capex allowance to $6286 million. Energex's revised capex proposal is set out in table 7.

Table 7: Energex's original and revised capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Original capex	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0
Revised capex	1232.1	1275.1	1265.0	1238.5	1275.7	6286.3
Difference	–7.4	5.5	–37.0	–54.0	–86.8	–179.6

Energex did not accept the findings of the draft decision in relation to growth capex, non–system capex and indirect capex costs. Energex's revised capex proposal of $6286 million is approximately $180 million lower than its original capex proposal. Table 8 shows the annual profile of Energex's revised capex proposal by category.

Table 8: Energex's revised capex proposal by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
System capex	1040.2	1147.8	1165.2	1174.6	1191.8	5719.6
Non–system assets	191.9	127.4	99.8	63.8	83.9	566.7
Revised total capex	1232.1	1275.1	1265.0	1238.5	1275.7	6286.3

Ergon Energy

Ergon Energy included a capex allowance of $6274 million ($2009–10) for the next regulatory control period. Ergon Energy's revised capex proposal is set out in table 9.

Table 9: Ergon Energy's original and revised capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Original capex	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9
Revised capex	1123.2	1222.1	1232.0	1293.5	1403.4	6274.1
Difference	37.0	22.2	54.7	65.4	61.9	241.2

Ergon Energy did not accept the findings of the draft decision, except in relation to sponsorship and community engagement capex and, in part, non–system ICT capex and input cost escalation. Ergon Energy's revised capex proposal of $6274 million is approximately $241 million higher than its original capex proposal. Table 10 shows the annual profile of Ergon Energy's revised capex proposal by category.

Table 10: Ergon Energy's revised capex proposal by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Asset replacement	181.2	222.6	261.7	285.9	305.0	1256.4
Corporation initiated augmentation	273.3	355.8	423.0	487.9	536.3	2076.3
Customer initiated capital works	363.7	394.7	641.8	357.3	389.0	1846.5
Reliability and quality improvement	18.5	21.5	25.2	29.0	30.8	125.0
Other system	111.1	75.0	53.1	52.7	53.2	345.1
Non–system assets	175.4	152.6	127.3	80.7	89.0	625.0
Revised total capex	1123.2	1222.1	1232.0	1293.5	1403.4	6274.1

AER decision

Energex

The AER is not satisfied that Energex's proposed forecast capex allowance reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. Following its review of Energex's revised capex proposal, the AER has made the following adjustments:

- $273 million ($2009–10) reduction to growth capex to reflect a realistic expectation of demand
- $32 million ($2009–10) reduction to non–system capex to reflect the removal of unsupported contingencies in property project cost estimates

- $2 million ($2009–10) reduction to indirect costs associated with ICT services which do not reflect efficient costs
- $250 million ($2009–10) reduction to total capex to reflect the application of amended input cost escalators.

The AER considers these adjustments to be the minimum necessary to ensure Energex's capex forecast meets the capex criteria. Allowing for the adjustments listed above, the AER's estimate of forecast capex for Energex is $5783 million, as set out in table 11. The AER is satisfied that this estimate reasonably reflects the capex criteria, taking into account the capex factors.

Table 11: AER conclusion on Energex's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex revised proposed capex	1232.1	1275.1	1265.0	1238.5	1275.7	6286.3
Adjustment to growth capex	–36.5	–43.3	–55.1	–63.4	–74.6	–273.0
Adjustment to non–system capex	–38.0	8.7	–2.5	–	–	–31.8
Adjustment to indirect costs	–0.1	–0.3	–0.3	–0.3	–0.5	–1.6
Re-inclusion of indirect costs that were included in growth capex and non–system capex deductions	12.2	5.6	10.4	11.5	13.8	53.6
Adjustment to cost escalators	–43.8	–74.1	–59.6	–42.7	–30.3	–250.5
AER capex allowance	1125.8	1171.8	1157.7	1143.5	1184.1	5783.0

Ergon Energy

The AER is not satisfied that Ergon Energy's proposed forecast capex allowance reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. Following its review of Ergon Energy's revised capex proposal, the AER has made the following adjustments:

- $500 million reduction to customer initiated augmentation capex to reflect a revised scope for sub–transmission network augmentation and a realistic expectation of demand
- $402 million reduction to corporate initiated capital works capex to reflect a revised approach to estimating customer initiated capital works expenditure
- $119 million reduction to asset replacement capex to reflect a business as usual approach to forecasting expenditure in this category
- $26 million reduction to reliability and quality improvement capex to exclude expenditure associated with the feeder improvement program and reflect a revised forecasting methodology for this expenditure category

- $121 million reduction to non–system capex to exclude unsupported expenditure on major property projects and the ICT change program
- $5 million reduction to other system capex to reflect the removal of capex costs associated with trials of smart meters
- $1 million reduction to indirect costs associated with ICT services which do not reflect efficient costs
- $278 million reduction to total capex to reflect the application of amended input cost escalators as determined in appendix F.

The AER considers these adjustments to be the minimum necessary to ensure Ergon Energy's capex forecast meets the capex criteria. Allowing for the adjustments listed above, the AER's estimate of forecast capex for Ergon Energy is $4989 million, as set out in table 12. The AER is satisfied that this estimate reasonably reflects the capex criteria, taking into account the capex factors.

Table 12: AER conclusion on Ergon Energy's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy revised proposed capex	1123.2	1222.1	1232.0	1293.5	1403.4	6274.1
Adjustment to CIA capex	–19.6	–102.1	–114.9	–127.3	–135.6	–499.6
Adjustment to CICW capex	–73.9	–103.2	–56.5	–68.4	–100.4	–402.3
Adjustment to asset replacement capex	–9.9	–19.4	–30.9	–30.0	–28.6	–118.8
Adjustment to reliability and quality improvement capex	–0.7	–2.6	–5.2	–7.9	–9.5	–25.9
Adjustment to non–system capex	–17.9	–27.8	–32.8	–17.8	–24.7	–121.0
Adjustment to other system capex (smart meters)	–5.3	–0.2	–	–	–	–5.5
Adjustment to shared costs	–0.0	–0.1	–0.2	–0.4	–0.6	–1.3
Re-inclusion of shared costs that were included in growth, asset replacement, reliability, other system and non–system capex deductions	18.6	51.1	29.4	33.9	34.6	167.6
Adjustment to cost escalators	–36.7	–70.2	–63.8	–57.8	–50.0	–278.4
AER capex allowance	977.8	947.7	957.1	1017.9	1088.5	4988.9

Forecast operating expenditure

AER draft decision

Energex

The AER considered Energex's forecast opex allowance of $1843 million ($2009–10) did not reasonably reflect the opex criteria, including the opex objectives of the NER. Based on the advice of PB and other information, the AER applied a reduction of $256 million ($2009–10) for the next regulatory control period. This reduction was mostly a consequence of reductions in input costs and other adjustments to non–controllable opex components.

Ergon Energy

The AER considered Ergon Energy's forecast opex allowance of $1993 million ($2009–10) did not reasonably reflect the opex criteria, including the opex objectives of the NER. Based on the advice of PB and other information, the AER applied a reduction of $479 million ($2009–10) for the next regulatory control period. This reduction was mostly a consequence of reductions to input cost escalators, uncontrollable costs, preventative maintenance and vegetation management.

Revised regulatory proposals

Energex

Energex implemented the draft decision in respect of forecast opex except those aspects relating to:

- self insurance
- ICT overheads
- cost escalators
- dividend payout ratio.

In addition, Energex provided a forecast of costs associated with the solar bonus scheme.

Energex's total revised forecast opex for the next regulatory control period was $1617 million ($2009–10). Energex subsequently submitted a revised approach to cost escalation, which increased its total proposed opex allowance to $1670 million ($2009–10).

Ergon Energy

Ergon Energy did not accept the AER's conclusion and substituted an opex forecast of $1918 million ($2009–10) that included:

- revised labour cost escalators
- revised maintenance opex

- reinstated demand management, customer service and metering reading opex
- new opex relating to guaranteed service levels (GSL) reporting requirements
- revised self insurance opex
- reinstated shared costs (overheads).

In addition, Ergon Energy included a forecast for the solar bonus scheme costs and provided revised estimates for its GSL payment obligations in response to the QCA decision on GSL obligations.

AER decision

Energex

The AER considers that Energex's revised forecast opex of $1670 million ($2009–10) does not reasonably reflect the opex criteria, including the opex objectives. The AER has applied a reduction of $36 million to Energex's revised forecast opex. This represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Energex would require to achieve the opex objectives.

The AER's conclusion on Energex's total forecast opex allowance is set out in table 13.

Table 13: AER conclusion on Energex's total opex ($2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex's proposed forecast opex	314.8	317.2	324.8	332.3	327.6	1616.7
Energex's amended forecast opex	325.8	328.5	336.3	342.6	336.4	1669.7
Adjustments to controllable opex	–0.7	–0.7	–0.8	–0.8	–0.9	–4.0
Adjustments to self insurance	–0.2	–0.3	–0.3	–0.3	–0.4	–1.5
Adjustment to debt raising	–0.0	–0.1	–0.2	–0.2	–0.3	–0.8
Adjustment to input cost escalators	–10.5	–9.4	–9.4	–7.9	–5.9	–43.1
Adjustment for overheads removed in capex adjustments	3.2	1.5	2.7	3.0	3.5	13.9
Total AER approved opex	317.6	319.4	328.3	336.3	332.5	1634.1

Ergon Energy

The AER considers Ergon Energy's revised forecast opex of $1918 million ($2009–10) does not reasonably reflect the opex criteria, including the opex objectives. The AER has applied a reduction of $117 million to Ergon Energy's revised forecast opex. This represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Ergon Energy would require to achieve the opex objectives.

The AER's conclusion on Ergon Energy's total forecast opex allowance is set out in table 14.

Table 14: AER conclusion on Ergon Energy's total opex ($2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy's proposed forecast opex	372.7	387.7	389.2	388.8	379.3	1917.7
Adjustments to controllable opex	–20.1	–21.9	–21.1	–23.8	–25.9	–112.7
Adjustments to self insurance	–3.3	–3.3	–3.4	–3.5	–3.6	–17.2
Adjustment to debt raising costs	–0.1	–0.1	–0.3	–0.4	–0.6	–1.5
Adjustment to input cost escalators	–5.7	–8.4	–10.0	–10.6	–10.6	–45.4
Adjustment for overheads	7.8	14.4	13.8	12.3	12.1	60.4
Total AER approved opex	351.3	368.4	368.2	362.7	350.6	1801.2

Estimated corporate income tax

AER draft decision

The AER assessed each of the inputs to the post–tax revenue model (PTRM) that are used to calculate the expected cost of corporate income tax.

The AER considered that the Qld DNSPs' proposed tax remaining and standard asset lives were appropriate. The AER also considered the Qld DNSPs' proposed opening tax asset bases to be appropriate and reasonable. The AER considered the Qld DNSPs' regulatory proposals and the supporting information provided did not constitute persuasive evidence to justify a departure from a gamma of 0.65, as specified in the *Statement of regulatory intent* (SORI). In forming its view the AER considered the information provided by interested parties in response to the gamma determined in the SORI and considered it against its specified underlying criteria.

Using these inputs, the AER used the PTRM to calculate the allowance for corporate income tax, as set out in table 15.

Table 15: AER draft decision on corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	32.2	35.5	39.1	43.0	45.9	195.7
Ergon Energy	0.0	20.1	29.3	34.0	33.1	116.5

Note: Ergon Energy has no tax allowance for 2010–11 due to the carry forward of tax losses from previous years.

Revised regulatory proposals

Energex

Energex proposed a total tax allowance of $529 million for the next regulatory control period. The revised allowance reflected changes by Energex to various factors that affect revenues and costs including the matters discussed below.

Energex rejected the draft decision to apply a gamma of 0.65 to the calculation of corporate income tax. Energex resubmitted its proposed gamma of 0.2.

Energex also revised its opening tax asset base as at 1 July 2010 and remaining tax asset lives at this date. This was due to the revisions Energex made to capex for 2008–09 in its RFM.

Ergon Energy

Ergon Energy has proposed a total tax allowance of $376 million for the next regulatory control period. This revised allowance reflects changes to all factors that affect revenues and costs including the matters discussed below.

Ergon Energy rejected the draft decision to apply a gamma of 0.65 to the calculation of corporate income tax. Ergon Energy resubmitted its proposed gamma of 0.2.

In its revised PTRM, Ergon Energy updated its estimated tax loss carried forward for 2009–10, revising this estimate down by $148 million compared to the draft decision. It also revised its opening tax asset base as at 1 July 2010 and remaining tax asset lives at this date. This was due to the revisions Ergon Energy made to capex for 2008-09 and 2009–10 in its RFM.

AER decision

The AER considers that the gamma of 0.65 adopted in the WACC review and subsequently in the draft decision is the best estimate of gamma based on the most reliable evidence available. This is based on an assumed payout ratio of 100 per cent and a theta estimate of 0.65.

Professor Michael McKenzie, and Associate Professors Graham Partington and John Handley were engaged by the AER to advise on issues raised in relation to the estimation of gamma. Taking account of the advice of its consultants, the AER considers it appropriate to use estimates of theta from tax statistics as well as market based estimates of theta due to the high variability of market based estimates of theta. The AER considers that a theta estimate of 0.65, based on an estimate from tax statistics as well as an estimate from market prices, is better than a market based estimate alone. Applying a benchmark payout ratio of 100 per cent, results in a gamma of 0.65.

The AER considers that, subject to some minor adjustments, the tax inputs into the Qld DNSPs' PTRM and RFM are consistent with the tax provisions of the NER.

The allowances for corporate income tax determined by the AER are presented in table 16.

Table 16: AER conclusion on corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	32.5	35.1	38.5	42.5	45.6	194.3
Ergon Energy	9.6	27.4	29.6	34.4	33.4	134.4

Depreciation

AER draft decision

The AER assessed the remaining and standard asset lives used by the Qld DNSPs as inputs to their PTRM, and the resulting regulatory depreciation allowances. The AER accepted the standard asset lives proposed by the Qld DNSPs.

The AER accepted Energex's proposed remaining asset lives. The AER did not accept the remaining asset lives proposed by Ergon Energy due to an error which had a significant impact on Ergon Energy's depreciation allowance.

The AER also accepted Ergon Energy's claim for accelerated depreciation in relation to assets destroyed by Cyclone Larry, although the amount to be recovered was revised to reflect the timing of when these assets were written off in Ergon Energy's accounts.

On the basis of the AER's approved asset lives, opening RAB, and forecast capex allowance, the AER determined the Qld DNSPs' regulatory depreciation allowances for the next regulatory control period, as set out in table 17.

Table 17: AER draft decision on regulatory depreciation allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	87.1	97.2	108.9	120.6	121.7	535.6
Ergon Energy	151.0	158.3	157.9	171.4	152.2	790.8

Note: These depreciation allowances included equity raising costs that were amortised.
The depreciation allowance for Ergon Energy did not include its accelerated depreciation claim for destroyed assets. These assets were accounted for separately in the PTRM.

Revised regulatory proposals

Energex

Energex proposed a total regulatory depreciation allowance of $513 million for the next regulatory control period, reflecting revisions to its RAB and assets lives.

Energex stated that its revision to the opening RAB as at 1 July 2010 to account for actual capex in 2008–09 impacted on the calculation of remaining asset lives to apply for the next regulatory control period. Energex stated that its revised remaining asset lives were based on the same methodology reviewed and accepted by the AER in its draft decision.

Energex accepted the draft decision to include equity raising costs in the RAB and amortise these costs over a standard asset life, based on a weighted average life of all assets in the RAB at 1 July 2010. Energex stated that following the update of the capex for 2008–09 in the RAB, it had recalculated the standard asset life of the equity raising costs to be 46.1 years.

Ergon Energy

Ergon Energy proposed a total regulatory depreciation allowance of $782 million for the next regulatory control period, reflecting revisions to its RAB and revised assets lives.

Ergon Energy updated its RAB for actual capex for 2008–09 and provided a revised capex forecast for 2009–10 in its roll forward model. These changes affected the remaining lives of each asset class as at 1 July 2010.

Ergon Energy did not accept the draft decision to amortise equity raising costs. However, it applied the AER approach to amortising equity raising costs in the PTRM and recalculated a standard asset life for equity raising costs of 48.0 years.

AER decision

The AER identified an ATO determination that requires equity raising costs to have a standard tax asset life of 5 years, and has applied a standard tax asset life for equity raising costs of 5 years for the Qld DNSPs.

On the basis of the AER's approved asset lives, opening RAB, and forecast capex allowance, the AER determines the Qld DNSPs' regulatory depreciation allowances for the next regulatory control period, as set out in table 18.

Table 18: AER conclusion on regulatory depreciation for the Qld DNSPs ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	78.5	87.2	98.1	110.2	111.5	485.5
Ergon Energy	145.0	146.9	150.3	164.1	144.6	750.9

Cost of capital

AER draft decision

The AER calculated an indicative nominal vanilla WACC of 10.06 per cent for the Qld DNSPs. The indicative WACC was higher than that proposed by the Qld DNSPs because the risk–free rate and debt risk premium (DRP) had increased since the time the Qld DNSPs prepared their proposals. The WACC determined by the AER did not include the proposed convenience yield.

Revised regulatory proposals

The Qld DNSPs adopted a nominal vanilla WACC of 10.06 per cent consistent with the draft decision. In revising their WACCs, the Qld DNSPs altered the risk–free rate to that consistent with the draft decision and accepted the approach to estimate the DRP by reference to the CBASpectrum fair value curve.

AER decision

The AER determined a nominal vanilla WACC of 9.72 per cent for the Qld DNSPs. This WACC is based on the updated risk–free rate and DRP, based on the agreed averaging period. The inflation forecast has been updated based on the latest available Reserve Bank of Australia forecasts and targets. The other WACC parameters are based on the SORI, as there was no persuasive evidence justifying a departure on the basis of material change in circumstances.

Service target performance incentive scheme

AER draft decision

Energex

The AER determined that the national distribution STPIS would apply to Energex in the next regulatory control period in the following form:

- the reliability of supply component parameters will apply to Energex's CBD, urban and short rural network segments
- overall revenue at risk of ±2 per cent
- the incentive rates for each parameter are to be determined in accordance with clause 3.2.2 and appendix B of version 01.2 of the STPIS
- the performance targets for each parameter in each regulatory year of the next regulatory control period were set out at table 12.6 of the draft decision
- the GSL component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn the AER's GSL scheme will take effect from the day the jurisdictional scheme is withdrawn.

Ergon Energy

The AER determined that the national distribution STPIS would apply to Ergon Energy in the next regulatory control period in the following form:

- the reliability of supply component parameters will apply to Ergon Energy's urban, short–rural and long–rural network segments. The customer service component telephone answering parameter will also apply

- overall revenue at risk of ±2 per cent, inclusive of a ±0.2 per cent for the telephone answering parameter

- the incentive rates for each parameter is to be determined in accordance with clauses 3.2.2 and 5.3.2, and appendix B of version 01.2 of the STPIS

- the performance targets for each parameter in each regulatory year of the next regulatory control period were set out at table 12.7 of the draft decision

- the GSL component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn, the AER's GSL scheme will take effect from the day the jurisdictional scheme is withdrawn.

Revised regulatory proposals

Energex

Energex did not address the application of the STPIS set out in the draft decision.

Ergon Energy

Ergon Energy did not accept the performance targets established for its reliability of supply parameters. It submitted updated performance targets that incorporated 2008–09 data and stated these performance targets should apply.

AER decision

The AER confirms its draft decision to apply the national distribution STPIS to the Qld DNSPs. The applicable component and parameters are the system average interruption duration index and system average interruption frequency index reliability of supply parameters. The AER will apply the telephone answering customer service parameter to Ergon Energy but not to Energex. The AER confirms its decision to apply an overall revenue at risk of ±2 per cent.

The AER rejects the performance targets proposed by Ergon Energy and confirms the targets set out in the draft decision. The performance targets applying to Ergon Energy are set out at table 12.3 of this decision. The performance targets applying to Energex are set out at table 12.4 of this decision.

The AER updated the incentive rates to apply to the Qld DNSPs to allow for the amended revenues to be applied. The AER will apply the incentive rates set out in tables 12.5 and 12.6 of this decision.

Efficiency benefit sharing scheme

AER draft decision

The AER stated it would apply the EBSS, released in June 2008, to the Qld DNSPs for the next regulatory control period. The AER stated it would not adjust the EBSS for the consequences of changes in demand growth for the Qld DNSPs in the next regulatory control period.

The AER considered the following opex cost categories should be excluded from the operation of the EBSS for the next regulatory control period for the Qld DNSPs:

- debt raising costs
- insurance and self insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives, including the demand management innovation allowance (DMIA).

These are in addition to the costs of pass through events which are excluded by the EBSS. Benchmark efficient equity raising costs have been amortised and therefore are not included as an opex category.

Revised regulatory proposals

Both Qld DNSPs have proposed that opex associated with the smart grid smart city (SGSC) be excluded from the operation of the EBSS on the basis that funding for the SGSC will be externally provided and that opex costs associated with the SGSC project have not been included in the Qld DNSPs' revised regulatory proposals.

Energex submitted that uncontrollable opex that meets the relevant criteria under clause 6.6.1(j) of the NER but fails the AER's general nominated pass through event materiality threshold should be excluded from the operation of the EBSS.

Ergon Energy proposed the reporting deadline for the EBSS be 31 October of each year.

AER decision

The AER will apply the EBSS in accordance with its framework and approach paper for the Qld DNSPs published in November 2008. The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the DMIA
- other specific uncontrollable costs incurred and reported by the Qld DNSPs during the next regulatory control period, which the AER considers should be excluded after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and EBSS.

These excluded costs will be recognised in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS, which include non-network alternatives and recognised cost pass through events. A recognised cost pass through event is an event that satisfies the relevant materiality threshold and is approved by the AER.

The AER also considers that opex associated with the SGSC project will be excluded from the operation of the EBSS for the Qld DNSPs.

Demand management incentive scheme

AER draft decision

The AER stated that it would apply only the Part A – demand management innovation allowance (DMIA) component of the DMIS to the Qld DNSPs, as outlined in its AER's framework and approach. The DMIA would be capped at $5 million for each DNSP in the next regulatory control period. The capped amount would be allocated as an ex–ante annual allowance of $1 million, for each year of the next regulatory control period.

The ex–post review and operation of the DMIA would be as set out in the DMIS.

Revised regulatory proposals

Energex did not comment on the application of the DMIS.

Ergon Energy accepted the introduction of the DMIS in the form of the Part A – DMIA component in the next regulatory control period.

AER decision

The AER will apply the Part A – DMIA component of the DMIS to the Qld DNSPs as outlined in the draft decision. The DMIA will be capped at $5 million for each business over the next regulatory control period. The capped amount will be allocated to each business as an ex–ante annual allowance of $1 million, for each year of the next regulatory control period as part of this final decision.

The ex–post review and operation of the DMIA will be as set out in the DMIS.

Pass through arrangements

AER draft decision

The AER divided pass through events into two broad categories: specific nominated pass through events and a general nominated pass through event.

The AER accepted the following nominated pass through events for the Qld DNSPs:

- smart meter event
- carbon pollution reduction scheme event
- feed–in tariff event

- a general nominated pass through event.

The AER considered that the other proposed pass through events did not meet the AER's assessment criteria for a specific nominated pass through event. In many instances the AER considered the proposed events were likely to be regulatory change events or meet the definition of a general nominated pass through event.

For general nominated events the AER will apply a materiality threshold of 1 per cent of the smoothed revenue allowance specified in the distribution determination for each of the years of the next regulatory control period in which the costs are incurred. The AER will apply a materiality threshold to specific nominated events set to the administrative costs of assessing an application.

Revised regulatory proposals

Energex proposed two additional specific nominated pass through events: a significant storm event and a retailer failure event.

Ergon Energy accepted or agreed with many of the approaches in the draft decision. However, it sought clarification from the AER on a number of matters and proposed three additional pass through events it considered should be included as specific nominated pass through events.

AER decision

The AER confirms its draft decision to accept the following nominated pass through events for the Qld DNSPs:

- smart meter event
- CPRS event
- feed-in tariff event
- a general nominated pass through event.

In assessing a Qld DNSP's application for a cost pass through (whether in relation to a specific nominated event, a general nominated event or an event defined in the NER), the AER will take into account all of the matters listed in clause 6.6.1(j)(1)–(8) of the NER. These matters include the need to ensure that a Qld DNSP recovers only incremental costs, and the efficiency of a Qld DNSP's decisions and actions in relation to the event, including whether the Qld DNSP has failed to take action to reduce the magnitude of the event.

Building block revenue requirements

AER draft decision

The AER calculated the Qld DNSPs' revenue requirements and X factors based on its decisions regarding the building blocks.

Energex

The draft decision resulted in a total revenue requirement for the next regulatory control period of $7158 million, compared to $7515 million proposed by Energex. The main reasons for this reduction were:

- the removal of $748 million from Energex's forecast capex
- the removal of $257 million from Energex's forecast opex
- a reduced allowance for tax, reflecting in part a higher gamma than that proposed by Energex
- a reduced allowance for equity raising costs
- a higher WACC than proposed by Energex.

Ergon Energy

The draft decision resulted in a total revenue requirement over the next regulatory control period of $6364 million, compared to $6776 million proposed by Ergon Energy.

Subsequent to the draft decision, Ergon Energy advised there was an error in the way the adjustment for labour cost escalators had been made to the opex figures provided to the AER to assist it in modelling its draft decision. This error also affected the capex forecasts (to a lesser extent) through the allocation of overheads. The AER remodelled its draft decision making the appropriate correction. This resulted in a revised total revenue requirement over the next regulatory control period of $6526 million. Based on these revised numbers, the main reasons for the reduced revenue requirement compared to that contained in Ergon Energy's regulatory proposal are:

- the removal of $1041 million from Ergon Energy's forecast capex
- the removal of $253 million from Ergon Energy's forecast opex
- a reduced allowance for tax, reflecting in part a higher gamma than that proposed by Ergon Energy
- a reduced allowance for equity raising costs
- a higher WACC than proposed by Ergon Energy.

Revised regulatory proposals

Energex

Energex proposed a total revenue requirement for the next regulatory control period of $7569 million, compared to $7158 million allowed for in the draft decision. The components of Energex's proposed revenue requirement are shown in table 19.

Table 19: Energex's proposed annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	83.0	92.0	103.4	116.1	118.0
Return on capital[a]	789.2	909.4	1030.5	1153.8	1276.9
Operating expenditure[b]	323.5	333.9	350.3	367.1	370.7
Tax allowance	86.7	95.8	105.3	116.3	124.9
Capital contributions	–64.4	–68.5	–70.6	–73.1	–75.1
Revenue from shared assets	–4.0	–4.7	–5.5	–6.1	–5.7
Annual revenue requirements	1213.9	1357.9	1513.4	1674.0	1809.6
Expected revenues	1214.1	1348.9	1498.5	1664.8	1849.6
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[c] (%)	–26.52	–8.44	–8.44	–8.44	–8.44

(a) Includes equity raising costs.
(b) Includes debt raising costs, DMIA and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

Ergon Energy

Ergon Energy proposed a total revenue requirement for the next regulatory control period of $7252 million, compared to $6526 million as calculated for the revised draft decision. The components of Ergon Energy's proposed revenue requirement are shown in table 20.

Table 20: Ergon Energy's proposed annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	149.8	152.4	156.1	170.7	153.1
Return on capital[a]	722.0	829.0	946.9	1068.8	1199.7
Operating expenditure[b]	381.8	407.0	418.5	428.3	428.1
Tax allowance	25.5	75.1	82.4	96.9	96.1
Capital contributions	–137.3	–149.1	–132.7	–144.5	–166.2
Revenue from shared assets	–3.2	–3.3	–3.4	–3.5	–3.5
Accelerated depreciation	10.4	0	0	0	0
Annual revenue requirements	1149.1	1311.2	1467.9	1616.9	1707.3
Expected revenues	1208.1	1317.2	1436.2	1565.9	1707.3
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[c] (%)	–39.51	–6.42	–6.42	–6.42	–6.42

(a) Includes equity raising costs.
(b) Includes debt raising costs, DMIA and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

AER decision

Energex

The AER's decision results in a total revenue requirement over the next regulatory control period of $7011 million, compared to $7569 million proposed by Energex in its revised regulatory proposal. The AER's calculation of Energex's revenue requirements and X factors is shown in table 21. The main reasons for the reduction are:

- the removal of $321 million from Energex's forecast capex
- the removal of $335 million from Energex's proposed tax allowance, reflecting in part a higher gamma than that proposed by Energex
- a lower WACC than that proposed by Energex.

Table 21: AER decision on Energex's annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	78.5	87.2	98.1	110.2	111.5
Return on capital	764.5	874.8	988.5	1102.4	1215.1
Operating expenditure	326.6	336.7	354.8	372.5	377.6
Tax allowance	32.6	35.1	38.6	42.6	45.6
Capital contributions	–65.1	–69.1	–71.5	–74.2	–76.4
Revenue from shared assets	–4.0	–4.7	–5.5	–6.1	–5.7
Annual revenue requirements	1133.1	1259.9	1402.9	1547.5	1667.7
Expected revenues	1135.1	1255.6	1388.9	1536.4	1699.6
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors (%)	–18.20	–7.90	–7.90	–7.90	–7.90

In determining Energex's X factors, the AER was mindful of the long term interest of consumers, who prefer price changes to be as smooth as possible.[1] The AER was also mindful of clause 6.5.9(2) of the NER, which requires the divergence between the expected revenues and the annual revenue requirement for the last year of the next regulatory control period to be minimised. Balancing these factors, the AER reduced the X factors for 2012–13 to 2014–15 from –8.44 per cent to –7.90 per cent, while it reduced the X factor in 2010–11 from –26.52 per cent to –18.20 per cent. The resulting impacts in terms of retail electricity prices of the AER's decision to use these X factors, compared with Energex's proposal, is outlined in table 22.

[1] Section 7 of the NEL.

Table 22: Retail price impacts (%)

	2010–11	2011–12	2012–13	2013–14	2014–15
Energex's proposal					
Real impacts	8.8	1.9	1.9	1.9	1.9
Nominal impacts	10.1	2.9	2.9	2.9	2.9
AER's decision					
Real impacts	5.6	1.7	1.7	1.7	1.7
Nominal impacts	6.8	2.7	2.7	2.7	2.7

Note: Calculations assume distribution network charges make up 40 per cent of retail electricity prices and 3.6 per cent demand growth per annum for the next regulatory control period. Inflation of 2.52 per cent assumed for calculating the nominal impacts.

The price impacts above exclude the effects of any annual revenue adjustments for such things as under/over recovery of DUOS and any pass through costs. These adjustments will be accounted for as part of the annual price approval process.

Ergon Energy

The AER's decision results in a total revenue requirement over the next regulatory control period of $6554 million ($2009–10), compared to $7252 million proposed by Ergon Energy in its revised regulatory proposal. The AER's calculation of Ergon Energy's revenue requirements and X factors is shown in table 23. The main reasons for the reduction are:

- the removal of $1452 million from Ergon Energy's forecast capex
- the removal of $122 million from Ergon Energy's forecast opex
- the removal of $242 million from Ergon Energy's proposed tax allowance, reflecting in part a higher gamma than that proposed by Ergon Energy
- a lower WACC than that proposed by Ergon Energy.

Table 23: AER decision on Ergon Energy’s annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	145.0	146.9	150.3	164.1	144.6
Return on capital	694.7	782.4	867.7	956.2	1052.8
Operating expenditure	360.2	387.2	396.7	400.7	397.1
Tax allowance	9.6	27.4	29.6	34.4	33.4
Capital contributions	–111.8	–115.8	–120.4	–130.7	–141.5
Revenue from shared assets	–3.2	–3.3	–3.4	–3.4	–3.5
Accelerated depreciation	10.5				
Annual revenue requirements	1105.0	1224.8	1320.5	1421.3	1482.7
Expected revenues	1123.1	1210.1	1303.9	1404.9	1513.8
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors (%)	–29.61	–5.10	–5.10	–5.10	–5.10

In determining Ergon Energy’s X factors, the AER (as for Energex) balanced the interest of consumers, who prefer price changes to be as smooth as possible, and the requirements of clause 6.5.9(2) of the NER. Accordingly, the AER reduced the X factor in 2012–13 to 2014–15 from –6.42 per cent to –5.10 per cent, while it reduced the X factor in 2010–11 from –39.51 per cent to –29.61 per cent. The resulting impacts in terms of retail electricity prices of the AER’s decision to use these X factors, compared with Ergon Energy’s proposal, is outlined in table 24.

Table 24: Retail price impacts (%)

	2010–11	2011–12	2012–13	2013–14	2014–15
Ergon Energy proposal					
Real impacts	14.2	1.3	1.3	1.3	1.3
Nominal impacts	15.5	2.4	2.4	2.4	2.4
AER decision					
Real impacts	10.3	0.8	0.8	0.8	0.8
Nominal impacts	11.6	1.8	1.8	1.8	1.8

Note: Calculations assume distribution network charges make up 40 per cent of retail electricity prices and 3.0 per cent demand growth per annum for the next regulatory control period. Inflation of 2.52 per cent assumed for calculating the nominal impacts.

The price impacts above exclude the effects of any annual revenue adjustments for such things as under/over recovery of DUOS and any pass through costs. These adjustments will be accounted for as part of the annual price approval process.

Alternative control services – street lighting

AER draft decision

Energex

The AER approved a price cap control mechanism for Energex's street lighting services for the first regulatory year of the next regulatory control period, and a price path for the remaining regulatory years of the next regulatory control period.

Compliance with the price cap control mechanism was to be demonstrated by Energex providing, as part of its pricing proposal, the price for each street lighting service in the relevant regulatory year.

Ergon Energy

The AER approved a price cap control mechanism for Ergon Energy's street lighting services for the first regulatory year of the next regulatory control period, and a price path for the remaining regulatory years of the next regulatory control period. The AER required Ergon Energy to provide, as part of its revised regulatory proposal, a forecast capex allowance for its new street lighting assets (category 1 street lighting services) in the next regulatory control period. This allowance was to be incorporated into its limited building block model.

The AER considered its classification of *supply enhancement* and *rearrangements of network asset* services as quoted services accurately captured Ergon Energy's proposed treatment of its category 3 street lighting services.

Compliance with the price cap control mechanism was to be demonstrated by Ergon Energy providing, as part of its pricing proposal, the price for each street lighting service in the relevant regulatory year.

Revised regulatory proposals

Energex accepted the draft decision with the exception of the application of input cost escalators.

Ergon Energy accepted the draft decision with the following exceptions:

- the opening street lighting asset base was revised to include 2008–09 actual capex and disposals and the capex and asset disposals expected to be incurred in 2009–10 were also updated
- a forecast capex requirement of $51 million was proposed for the next regulatory control period, including capex associated with new street lighting assets
- requested the energy efficient luminaire rollout be treated as a nominated pass through event

- the application of input cost escalators.

AER decision

The AER's limited building block approach for street lighting services incorporates the following building blocks:

- an indexed street light asset base
- depreciation
- return on capital
- forecast opex
- estimated cost of corporate income tax.

The results of the AER's review of the building block elements for the Qld DNSPs are shown in tables 25 and 26 respectively.

Table 25: AER conclusion on Energex's street lighting revenue requirement and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	6.7	7.6	8.5	9.6	10.7
Return on capital	9.4	10.6	11.7	12.8	14.0
Operating expenditure	2.2	2.2	2.2	2.2	2.2
Tax allowance	12.1	12.6	13.2	13.8	14.2
Non–system revenue allocation	1.5	1.9	2.2	2.5	2.3
Annual revenue requirement	32.0	34.8	37.8	40.9	43.4
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors (%)	25.04	–3.65	–3.65	–3.65	–3.65
Smoothed annual revenue requirement	33.2	35.3	37.5	39.9	42.4

Table 26: AER conclusion on Ergon Energy's street lighting revenue requirement and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	6.3	6.8	7.3	7.9	8.4
Return on capital	6.8	6.7	6.5	6.3	6.1
Operating expenditure	14.0	14.0	14.1	14.6	15.1
Tax allowance	0.8	0.8	0.8	0.8	0.8
Annual revenue requirement	27.9	28.3	28.7	29.6	30.5
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors (%)	–73.99	–1.00	–1.00	–1.00	–1.00
Smoothed annual revenue requirement	27.1	28.0	29.0	30.0	31.1

The AER has determined indicative prices for the Qld DNSPs' respective street lighting services, set to recover the approved revenue requirements. Compliance with the price cap control mechanism is to be demonstrated by each Qld DNSP providing, as part of its pricing proposal, the price for each street lighting service in the relevant regulatory year consistent with this decision.

The AER's approved prices represent the maximum price to be charged for each street lighting service in each regulatory year of the next regulatory control period.

Alternative control services – quoted and fee based services

AER draft decision

The AER approved the formula proposed by Energex to derive the prices for quoted and fee based services after an amendment to remove the profit margin component.

The AER approved the formula proposed by Ergon Energy to derive the prices for quoted and fee based services after an amendment to remove the other costs component.

For quoted services, the AER determined the capped price of providing the illustrative configuration of each individual quoted services in the first regulatory year of the next regulatory control period. The AER also established a price path for each individual formula component. The AER stated compliance with the price cap control mechanism was to be demonstrated by the Qld DNSPs providing, as part of their pricing proposals, the capped price and calculation for each illustrative configuration of each individual quoted service in the relevant regulatory year.

For fee based services, the AER determined a capped price for individual services for the first regulatory year of the next regulatory control period and established a price path for each service. The AER stated compliance with the price cap control mechanism was to be demonstrated by the Qld DNSPs providing, as part of their pricing proposals, the capped price for each individual fee based service in the relevant regulatory year.

Revised regulatory proposals

Energex

Energex accepted the draft decision with the exception of the following aspects:

- the removal of the profit margin formula component
- the AER's application of input cost escalators, on costs and overhead rates.

Energex also provided updated information the AER requested in the draft decision relating to the customer connections employee classification and the capital allowance.

Ergon Energy

Ergon Energy accepted the draft decision with the exception of the following aspects:

- the removal of the other costs formula component
- the forecast labour on–cost rate
- the AER's application of input cost escalators.

Ergon Energy also provided updated information the AER requested in the draft decision relating to: the contractor, system operator and trainee employee classifications; allocation of employee classifications to its illustrative examples; and the capital allowance.

AER decision

The AER approves the formula proposed by Energex to derive the prices for quoted and fee based services with the exception of the profit margin component.

The AER approves the formula proposed by Ergon Energy to derive the prices for quoted and fee based services with the exception of the 'other costs' component.

The AER considers it appropriate to include greater flexibility in the application of input cost escalators, on cost and overhead rates within the formula based price cap control mechanisms for quoted and fee based services.

The AER has determined the capped price of providing the illustrative configuration of each individual quoted services and fee based service in the first regulatory year of the next regulatory control period. The AER has specified a methodology for deriving a price path for each individual formula component in the remaining regulatory years of the next regulatory control period.

1 Introduction

Under the National Electricity Law (NEL) and the National Electricity Rules (NER),[1] the Australian Energy Regulator (AER) is responsible for the economic regulation of certain electricity distribution services provided by distribution network service providers (DNSPs) in the National Electricity Market (NEM).

The Queensland Competition Authority (QCA) made the current regulatory determinations for Energex and Ergon Energy (the Qld DNSPs) for a five year period from 1 July 2005 to 30 June 2010 (the current regulatory control period) under the National Electricity Code, which has been replaced by the NER. The Qld DNSPs own and operate the electricity distribution networks in Queensland.

The AER has made the distribution determinations for the Qld DNSPs according to the relevant requirements of chapter 6 of the NER and the transitional requirements for Queensland contained in chapter 11 of the NER. The AER's principal task is to set the revenues the Qld DNSPs can recover for the provision of direct control services in the period 1 July 2010 to 30 June 2015 (the next regulatory control period).

On 30 June 2009 the Qld DNSPs submitted their regulatory proposals for the next regulatory control period to the AER. On 30 November 2009 the AER published its draft decision and draft distribution determinations for the Qld DNSPs.[2] In mid January 2010 the Qld DNSPs submitted revised regulatory proposals in response to the draft decision.[3] The revised regulatory proposals were published by the AER on 15 January 2010.

This decision and the Qld DNSPs' distribution determinations should be read in conjunction with the draft decision and draft distribution determinations for the Qld DNSPs.

1.1 AER draft decision

The AER calculated the Qld DNSPs' revenue requirements and X factors based on its decisions regarding the building blocks.

Energex

The draft decision resulted in a total revenue requirement for the next regulatory control period of $7158 million, compared to $7515 million proposed by Energex.

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1 The AER uses the version of the NER that is in effect on the date a regulatory proposal is lodged. For the purposes of this decision and the distribution determinations for Energex and Ergon Energy, the relevant version of the NER is version 29, which was in effect on 30 June 2009.

2 AER, *Draft decision, Queensland draft distribution determination 2010–11 to 2014–15*, (Draft decision, Queensland draft distribution determination), 25 November 2009; AER, *Draft distribution determination Energex, 1 July 2010 – 30 June 2015*, 25 November 2009; and AER, *Draft distribution determination Ergon Energy, 1 July 2010 – 30 June 2015*, 25 November 2009.

3 Energex, *Revised regulatory proposal for the period July 2010–June 2015*, (Revised regulatory proposal), January 2010; and Ergon Energy, *Revised regulatory proposal to the Australian Energy Regulator, Distribution services for 1 July 2010 to 30 June 2015*, (Revised regulatory proposal), January 2010.

The main reasons for the difference between the AER's and Energex's estimated total revenue requirement reflect the net effect of:

- removal of $748 million from Energex's forecast capital expenditure (capex)
- removal of $257 million from Energex's forecast operating expenditure (opex)
- a reduced allowance for tax, reflecting in part a higher gamma than proposed by Energex
- a reduced allowance for equity raising costs
- a higher weighted average cost of capital (WACC) than proposed by Energex.

The AER determined Energex's opening regulatory asset base (RAB) to be $7887 million ($2009–10) as at 1 July 2010.[4] The total capex allowance used by the AER in the building block calculation was $5718 million ($2009–10).[5] The total opex allowance used by the AER in the building block calculation was $1586 million ($2009–10).[6]

The AER specified the negotiated distribution service criteria to apply to Energex. Energex does not have any services classified as negotiated distribution services, and hence did not submit a negotiating framework as part of its regulatory proposal.

Ergon Energy

The draft decision resulted in a total revenue requirement over the next regulatory control period of $6364 million, compared to $6776 million proposed by Ergon Energy. The main reasons for the difference between the AER's and Ergon Energy's estimated total revenue requirement reflect the net effect of:

- removal of $1041 million from Ergon Energy's forecast capex
- removal of $253 million from Ergon Energy's forecast opex
- a reduced allowance for tax, reflecting in part a higher gamma than proposed by Ergon Energy
- a reduced allowance for equity raising costs
- the addition of $106 million to Ergon Energy's opening RAB as at 1 July 2005
- the correction of remaining asset lives, which has the effect of increasing the depreciation allowance
- a higher WACC than proposed by Ergon Energy.

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4 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 358.
5 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 129.
6 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 193.

The AER determined Ergon Energy's opening RAB to be $7105 million ($2009–10) as at 1 July 2010.[7] The total capex allowance used by the AER in the building block calculation was $5013 million ($2009–10).[8] The total opex allowance used by the AER in the building block calculation was $1514 million ($2009–10).[9]

The AER specified the negotiated distribution service criteria to apply to Ergon Energy. Ergon Energy does not have any services classified as negotiated distribution services, and hence did not submit a negotiating framework as part of its regulatory proposal.

1.2 Revised regulatory proposals

The Qld DNSPs submitted their revised regulatory proposals on 16 January 2010.

Energex

Energex set out an annual revenue requirement that increased from $1214 million in 2010–11 to $1810 million in 2014–15 (nominal), and a total annual revenue requirement of $7569 million for the next regulatory control period.[10] This is $54 million greater than its original total annual revenue requirement of $7515 million.

Energex's revised opening RAB was $7938 million (as at 1 July 2010). This compares to its original opening RAB of $7984 million (as at 1 July 2010). The revised RAB incorporates an updated capex forecast for 2009–10. Energex accepted all aspects of the draft decision on the opening RAB.[11]

Energex's revised capex forecast for the next regulatory control period was $6070 million ($2009–10). This compares to its original capex forecast of $6466 million ($2009–10). Energex implemented most aspects of the draft decision relating to forecast capex, except growth capex, non–system capex, and overheads.[12]

Energex's revised forecast opex for the next regulatory control period was $1617 million ($2009–10). This compares to its original opex forecast of $1843 million ($2009–10). Energex implemented most aspects of the draft decision relating to opex, except those related to information and communications technology costs. Energex included an additional opex forecast for the solar bonus scheme tariff payments and administration costs.[13]

Energex applied the AER's revised input cost escalators in its revised regulatory proposal but made a further submission on these elements of its capex and opex forecasts. It provided revised forecasts of maximum demand.[14]

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7 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 362.
8 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 130.
9 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 195.
10 Energex, *Revised regulatory proposal*, January 2010, p. 51.
11 Energex, *Revised regulatory proposal*, January 2010, p. 33.
12 Energex, *Revised regulatory proposal*, January 2010, p. 19.
13 Energex, *Revised regulatory proposal*, January 2010, p. 31.
14 Energex, *Revised regulatory proposal*, January 2010, pp. 4–11.

Energex accepted most other elements of the draft decision relating to the classification of services, arrangements for negotiation, control mechanisms, efficiency benefit sharing scheme (EBSS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS) and depreciation. It did not accept other aspects of the draft decision, for example relating to treatment of capital contributions and pass through events.

Ergon Energy

Ergon Energy set out an annual revenue requirement that increased from $1149 million in 2010–11 to $1707 million in 2014–15 (nominal), and a total annual revenue requirement of $7252 million for the next regulatory control period.[15] This is $458 million greater than its original total annual revenue requirement of $6777 million.

Ergon Energy's revised opening RAB was $7174 million (as at 1 July 2009). This compares to its original opening RAB of $6999 million (as at 1 July 2010). The revised RAB incorporates an updated capex forecast for 2009–10. Ergon Energy accepted all aspects of the draft decision on the opening RAB.[16]

Ergon Energy's revised capex forecast for the next regulatory control period was $6274 million ($2009–10). This compares to its original capex forecast of $6033 million ($2009–10). It did not implement those aspects of the draft decision on forecast capex relating to growth capex, non–system capex, shared costs, replacement capex, and reliability capex. The revised capex forecasts included the impact of revised input cost escalators, and also reflected Ergon Energy's revised maximum demand forecasts.[17]

Ergon Energy's revised forecast opex for the next regulatory control period was $1894 million ($2009–10). This compares to its original opex forecast of $1993 million ($2009–10). Ergon Energy did not implement the draft decision on forecast opex relating to:[18]

- preventative maintenance
- corrective maintenance
- forced maintenance
- customer service costs
- demand management
- shared costs
- debt raising and equity raising costs.

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15 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 216.
16 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 55.
17 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 83 and 143.
18 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 176.

Ergon Energy accepted most other elements of the draft decision relating to the classification of services, arrangements for negotiation, control mechanisms, EBSS, STPIS, DMIS and depreciation. It did not accept other aspects of the draft decision, for example relating to the solar bonus scheme and cost pass throughs.

1.3 Review process

The AER reviewed the Qld DNSPs' regulatory proposals in accordance with the review process outlined in Part E of chapter 6 of the NER. This process has involved:

- Pre–consultation—the AER consulted with the Qld DNSPs about the development of the regulatory information notice, pro forma templates and guidelines.

- Framework and approach (stage 1)—the AER consulted with the Qld DNSPs and interested parties about the development of a classification of services and control mechanism to be applied in the distribution determinations. The framework and approach (stage 1) was published in August 2008, as required under clauses 6.8.1 and 11.16.6 of the NER.

- Framework and approach (stage 2)—the AER consulted with the Qld DNSPs about the application of schemes (EBSS, DMIS and STPIS) to be applied in the distribution determinations. The framework and approach (stage 2) was published in November 2008, as required under clause 6.8.1 and clause 11.16.6 of the NER.

- Cost allocation methods—in February 2009, the AER approved the cost allocation methods of the Qld DNSPs under clause 6.15.4 of the NER.

- Regulatory proposal—the Qld DNSPs submitted their regulatory proposals to the AER on 30 June 2009. The AER assessed the Qld DNSPs' regulatory proposals against chapter 6 of the NER.

- Public consultation—on 17 July 2009, the AER published the Qld DNSPs' regulatory proposals and the AER's proposed negotiated distribution service criteria and called for submissions from interested parties. On 3 August 2009, the AER held a public forum in Brisbane on the Qld DNSPs' regulatory proposals, where the Qld DNSPs made presentations.

- Submissions—the AER received 11 submissions on the Qld DNSPs' regulatory proposals and the AER's proposed negotiated distribution service criteria. The submissions are listed in appendix R of the draft decision.

- Assessment by technical experts—the AER engaged Parsons Brinckerhoff Strategic Consulting (PB) as a technical expert to advise it on a number of key aspects of the regulatory proposals.[19] PB provided its advice to the AER based on its review. The AER considered this advice in making its draft distribution determinations. The terms of reference guiding PB's review are set out as an appendix to its report.

[19] PB is a group of engineering and business consultants with a primary focus on electric power, gas and other allied sectors.

- Additional technical advice—the AER engaged Energy and Management Services to provide the AER with technical and engineering advice throughout the review process.[20] Energy and Management Services assisted the AER in reviewing the technical aspects of material contained in the Qld DNSPs' proposals, submissions and PB's report.

- Assessment by demand forecast experts—the AER engaged McLennan Magasanik Associates (MMA) as a technical expert to advise in relation to demand forecasts.

- Other specialist advice—the AER engaged Access Economics[21] to provide a forecast of Queensland and South Australian labour costs relevant to electricity distribution businesses. McGrathNicol Corporate Advisory (McGrathNicol) was engaged to review elements of the tax asset bases for the post–tax revenue model.

- Draft decision—the draft decision and draft distribution determinations were released on 30 November 2009 and the AER requested submissions from interested parties.

- Public consultation—the AER held a public forum in Brisbane on 8 December 2009 to explain its draft decision and receive oral submissions from interested parties.

- Revised regulatory proposals—Energex submitted its revised regulatory proposal to the AER on 13 January 2010. Ergon Energy submitted its revised regulatory proposal to the AER on 14 January 2010. The AER published the Qld DNSPs' revised regulatory proposals on 15 January 2010.

- Submissions—the AER received 9 submissions on its draft decision and draft distribution determinations and the Qld DNSPs' revised regulatory proposals. These are listed at appendix M of this decision.

- Assessment by technical experts—the AER engaged PB as a technical expert to advise it on the capex, opex and service standards components of the revised regulatory proposals. MMA provided the AER with advice on maximum demand forecasts in Queensland.

- Other specialist advice—the AER also engaged Access Economics to provide updated forecasts of Queensland and South Australian labour costs relevant to electricity distribution businesses. McGrathNicol was engaged to review elements of the tax asset base for the post–tax revenue model. Professor Michael McKenzie, and Associate Professors Graham Partington and John Handley were engaged by the AER to provide advice on issues raised in relation to the estimation of gamma.

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20 Energy and Management Services is an engineering consulting firm.

21 Access Economics is an economic consulting firm that specialises in economic modelling, forecasting and policy analysis.

- Decision—The AER made its decision and distribution determinations for the Qld DNSPs on 4 May 2010.

1.4 Structure of decision

This decision sets out the AER's consideration of the Qld DNSPs' revised regulatory proposals, together with the negotiated distribution service criteria to apply to the Qld DNSPs. The decision includes consideration of substantive issues raised in submissions. Except as specified in this decision, the AER confirms its conclusions set out in the draft decision. Therefore, this decision should be read in conjunction with the draft decision published by the AER on 30 November 2009.

The structure of the decision is set out as follows:

- chapters 2 to 4 address the classification of services, arrangements for negotiation and the control mechanisms for standard control services
- chapters 5 to 11 relate to key elements of the building block calculation
- chapters 12 to 15 set out the relevant schemes and pass through arrangements
- chapter 16 sets out the annual building block revenue requirements for the next regulatory control period
- chapters 17 to 18 set out the control mechanisms for alternative control services and the AER's review of these services.

2 Classification of services

This chapter sets out the AER's consideration of issues raised in response to the draft decision on the classification of services for the Qld DNSPs. It also sets out the procedures to be used by the Qld DNSPs to assign and reassign customers to tariff classes.

A distribution service is a service provided by means of or in connection with a distribution network, together with the connection assets, which is connected to transmission system or another distribution system.[22] Distribution services are classified as either direct control services, negotiated distribution services, or as unregulated distribution services.[23]

2.1 AER draft decision

The AER applied the service classifications set out in the framework and approach for the Qld DNSPs' services. The AER's procedure for assigning and reassigning customers to tariff classes for the Qld DNSPs was set out in appendix B of the draft decision.[24]

2.2 Revised regulatory proposals

Ergon Energy accepted the classification of distribution services set out in the draft decision but did not accept the AER's procedure for assigning and reassigning customers to tariff classes.[25]

Energex did not address the classification of services in its revised regulatory proposal.

2.3 Submissions

The Queensland Council of Social Service (QCOSS) submitted that DNSPs currently allocate costs across customer classes based on the assumption that residential consumers are a homogeneous customer class. However, it considered that vulnerable customers within the residential class have different cost drivers, notably a lower penetration of air conditioning, which could distinguish them as a different customer class. QCOSS requested that the AER consider these different characteristics of low income consumers in its assessment under NER clause 6.18.4. However, QCOSS acknowledged that the Qld DNSPs currently do not have sufficiently detailed information to distinguish retail customers according to the characteristics identified by it, that is, air conditioning installations.[26]

QCOSS suggested possible alternative tariff designs for consideration by the DNSPs to address the issue of vulnerable consumer classes and noted that this issue is part of

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22 NER, chapter 10.
23 NER, clause 6.2.1(a).
24 AER, *Draft decision, Queensland draft distribution determination*, November 2010, p. 19.
25 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 43.
26 QCOSS, *Submission on the AER draft decision – Queensland distribution determination process 2010–15*, February 2010.

a broader range of concerns requiring a coordinated approach between governments and regulators. It referred to comments made at the pre–determination conference regarding the AER's discretion under the NEL relating to pricing, and argued that the restrictions on the AER's discretion are at the total revenue level and approved X factor. QCOSS referenced the NER clause 6.5.9 in support of its view. In conclusion, QCOSS stated that the pricing principles in clause 6.18.5 of the NER do not prevent the AER from requesting DNSPs to offer different tariff structures to particular customer classes.[27]

2.4 Issues and AER considerations

Ergon Energy confirmed that it is subject to the provisions of the NER in relation to the assignment or reassignment of the customers to tariff classes but considered the AER's procedure in appendix B of the draft decision is potentially inconsistent with national market systems and processes.[28] Ergon Energy's key concern appeared to relate to clause 6 of the AER's procedure which requires it to notify customers, in writing, of the tariff class to which a customer is assigned or reassigned.

Ergon Energy considered that processes are in place that recognise customers' rights to review and to object to a tariff class assignment under the current jurisdictional standard coordination agreement.[29] It submitted that the AER has not had regard to existing market systems and processes.[30] Therefore, it concluded that the AER's notification requirement is not beneficial to retailers or customers.

The AER acknowledges the market settlement and transfer solution (MSATS) procedures require a DNSP to notify a retailer of the tariff code applicable to a customer or any changes to it.

Ergon Energy stated the applicable coordination agreement under the Queensland *Electricity Distribution Code* already provides for retailers to request from DNSPs a review of customer tariffs, the process of advising outcomes and a dispute resolution process.[31] Ergon Energy's tariff guide also requires it to inform retailers of any changes to network tariffs initiated by it and allows customers to object via the retailer.[32]

The AER notes these obligations (and rights) of the retailers are based on jurisdictional legislative requirements which are not necessarily consistent across the NEM.[33] Further, the MSATS procedure is not part of the system of assessment and review of decisions to assign or reassign customers to tariff classes and represents notification between retailers and distributors.

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27 QCOSS, *Submission on the draft decision*, February 2010.
28 Ergon Energy, response to AER question ERG.RRP.20 and 22, 2 March 2010, confidential.
29 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP 935c general comments.
30 Ergon Energy, response to AER question ERG.RRP.20, 2 March 2010, confidential.
31 Ergon Energy, response to AER question ERG.RRP.20, 2 March 2010, confidential.
32 Ergon Energy, *Network use of system tariff guide 2009–2010*, release 2 20 November 2009, section 3(e).
33 The Ministerial Council on Energy is currently developing a nationally applicable energy customer framework including rules and regulations relating to the energy retail sector. See: http://www.ret.gov.au/Documents/mce/default.html

The AER considers the direct notification obligation under its procedure for assigning or reassigning customers to tariff classes is consistent with its objective of achieving a nationally consistent procedure. This nationally consistent procedure recognises that a customer has the right to object to tariff class assignments or reassignment decisions and that, accordingly, the customer should be directly notified of its rights by the DNSP. The AER considers that this approach, based on direct notification, right of objection and external dispute resolution underpins an effective system of assessment and review rather than indirect notification.[34]

Ergon Energy commented on the 'meaningfulness' of the DNSPs' tariff class information to its customers and stated approximately 99.8 per cent of its customers are on regulated retail sales contracts and are supplied on notified prices set by the government.[35] The AER acknowledges these circumstances but notes that the procedure for assigning and reassigning customers to tariff classes developed by the AER is a general procedure applicable to all DNSPs across the NEM. Further, as per the AER's procedure, all customers as at 1 July 2010 continue to be in the same tariff class as at that day. Hence, provision of tariff class information to existing customers will occur only if and when these existing customers are reassigned. The AER therefore considers that it is inappropriate to customise the procedure for Ergon Energy's circumstances.

Ergon Energy also contended that the requirement for a DNSP to notify the customer of the tariff class to which it is assigned or reassigned prior to assignment or reassignment occurring, was not reasonable. It was concerned that this requirement would create delays in achieving the jurisdictional obligations to complete connections within set timeframes as the DNSP is required to offer a customer a reasonable time to make an objection before the actual assignment.[36] The AER considers that Ergon Energy has misinterpreted the notification requirement to mean that the customer must be provided sufficient time to object prior to the actual tariff class assignment. The AER only requires that notification occur prior to actual assignment and does not set a time for objection or dispute resolution prior to the assignment.

Ergon Energy requested clarification relating to the use of the terms tariff and tariff class in the draft decision.[37] The AER has addressed this in appendix B of this decision and has included the term tariff class in clauses 5 and 10 where it had been inadvertently referred to as tariffs in the draft decision.

Ergon Energy noted that clause 6.18.3 of the NER requires separate tariff classes for customers to whom standard control and alternative control services are supplied. It stated that the application of appendix B to alternative control services is inappropriate, not meaningful and would be difficult and inefficient to apply in practice. It requested that the AER clarify whether appendix B is intended to apply to

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34 NER, clause 6.18.4(a)(4).

35 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP 935c general comments: alternative control services.

36 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP 935c general comments: alternative control services.

37 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP 935c general comments.

alternative control services.[38] The AER confirms that clause 6.18.3 of the NER applies to alternative control services. The AER considers that appendix B is intended to apply to all direct control services, including alternative control services.

The AER notes Ergon Energy's interpretation of the role of the Queensland Energy Ombudsman and its conclusion that tariff class objections are not within the Ombudsman's powers.[39] The AER's procedures set out in appendix B recognise the Ombudsman as the dispute resolution body only to the extent that it has jurisdiction over such matters. In the absence of jurisdiction over such matters, the customer's right to dispute resolution under Part 10 of the NEL is recognised in clause 7(c) of the procedure.

Ergon Energy commented that its current processes allow for customers to request a review of their existing tariff class whereas the AER's procedure could be interpreted to mean that existing customers as at 1 July 2010 have no right to request a review. The AER's procedure is not intended to restrict or remove customer rights and can operate concurrently with any existing review procedure to the extent that they are not inconsistent with or take away rights created by the AER's procedure set out in appendix B. The fact that the AER's procedure deems that customers prior to 1 July 2010 will continue in the same tariff class does not remove their right to have their tariff classes reviewed or reassigned to another tariff class.

Ergon Energy questioned the need for any price adjustment to be carried out as part of the next annual price review in the event that a customers' objection to an assignment or reassignment decision is upheld by the review body. Ergon Energy appears to be concerned that the application of the adjustment as set out in clause 10 of appendix B from the next annual pricing review could be financially disadvantageous to customers and therefore an adjustment during the pricing year should be accommodated.[40]

Clause 10 of the procedure is based on the premise that the customer has been assigned to the new tariff class from the date the DNSP made its decision, which could have been during a pricing year. However, in the event that the customer's objection is upheld by the review body, then it is entitled to have its prices corrected to reconcile any price impacts which may have occurred since the DNSP's assignment/reassignment decision. It is this entitlement that has to be implemented via an adjustment at the next annual pricing review. The AER considers that the inclusion of this clause ensures that the customer has a right to any overpayments that may have occurred and the next annual pricing review is the most appropriate time to undertake this correction.

In response to the QCOSS submission the AER notes that clause 6.12.1 of the NER does not identify any constituent decisions that require the AER to determine tariff

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[38] Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP 935c general comments: alternative control services.

[39] Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP 935c general comments: section 7b Ombudsman scheme.

[40] Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP 935c general comments: alternative control services.

classes or review tariff structures as part of the distribution determination. Rather, in accordance with clause 6.12.1(17) of the NER the AER is required to make 'a decision on the procedures for assigning customers to tariff classes, or re-assigning customers for one tariff class to another (including any applicable restrictions).' This decision does not go to the nature of a tariff class and consequently the AER cannot influence the determination of tariff classes under this provision. Further, the pricing principles in clause 6.18.5 of the NER referred to by QCOSS relate to the revenue to be recovered from tariff classes and are applicable at the stage of reviewing a DNSP's pricing proposal, not as part of a distribution determination.

The AER therefore does not agree with QCOSS that in making a distribution determination it has authority to request a DNSP to offer particular tariff structures to particular classes of customers or review the nature of a tariff. The AER acknowledges that it has discretion over the X factor as set out in clause 6.5.9 of the NER, however, this has no impact on the decision the AER is required to make under clause 6.12.1(17) of the NER.

2.5 AER conclusion

2.5.1 Classification of services

The AER's service classifications remain consistent with its draft decision and are set out in appendix A of this decision.

2.5.2 Assigning customers to tariff classes

The AER's procedures for assigning and reassigning customers to tariff classes for the Qld DNSPs are set out in appendix B of this decision.

2.6 AER decision

In accordance with clause 6.12.1(1) of the NER, the classification of services to apply to Energex is as set out in appendix A of this decision.

In accordance with clause 6.12.1(1) of the NER, the classification of services to apply to Ergon Energy is as set out in appendix A of this decision.

In accordance with clause 6.12.1(17) of the NER, the procedures for assigning customers to tariff classes or reassigning customers from one tariff class to another are specified in appendix B of this decision.

3 Arrangements for negotiation

A distribution determination imposes controls over the prices and revenues that DNSPs can recover from the provision of direct control services. However, services classified as negotiated distribution services do not have their terms and conditions determined by the AER, being instead subject to a process of negotiation and dispute resolution.

Facilitating the negotiating process are two instruments:

1. negotiated distribution service criteria (NDSC)—set out the criteria that DNSPs are to apply in negotiating the terms and conditions of access for its negotiated distribution services. The AER also applies the NDSC in resolving disputes regarding these terms and conditions.
2. negotiating framework—sets out the procedures to be followed during negotiations between a DNSP and any person wishing to receive a negotiated distribution service.

The Qld DNSPs do not have services classified as negotiated distribution services and are not required to submit a negotiating framework.

This chapter sets out the AER's considerations and conclusions on the NDSC to apply to the Qld DNSPs in the next regulatory control period. The AER did not receive submissions from other interested parties on the NDSC.

3.1 AER draft decision

The AER did not apply negotiating frameworks to the Qld DNSPs for the next regulatory control period, as neither had any services classified as negotiated distribution services.[41]

The AER considered it is required to publish a NDSC, irrespective of whether or not the Qld DNSPs provide negotiated distribution services. The NDSC applying to the Qld DNSPs for the next regulatory control period was in appendix C of the draft decision.[42]

3.2 Issues and AER considerations

The AER notes that no comments on the NDSC were received from the Qld DNSPs or other interested parties. As no submissions seeking consideration of amendments were received, the NDSC will apply unchanged from the draft decision.

3.3 AER conclusion

The NDSC to apply to the Qld DNSPs for the next regulatory control period are as set out in appendix C of this decision.

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[41] AER, *Draft decision, Queensland draft distribution determination*, November 2010, p. 20.
[42] AER, *Draft decision, Queensland draft distribution determination*, November 2010, p. 24.

3.4 AER decision

In accordance with clause 6.12.1(16) of the NER, the NDSC to apply to Energex for the next regulatory control period are in appendix C of this decision.

In accordance with clause 6.12.1(16) of the NER, the NDSC to apply to Ergon Energy for the next regulatory control period are in appendix C of this decision.

4 Control mechanism for standard control services

A distribution determination imposes controls over the prices, and revenues that DNSPs may recover from providing direct control services. Direct control services are categorised as either standard control services or alternative control services.

The AER published a framework and approach setting out the control mechanisms it proposes to apply to direct control services provided by the Qld DNSPs during the next regulatory control period.[43] For the Qld DNSPs' standard control services this control mechanism is a revenue cap. This chapter discusses how this mechanism will be applied and sets out how the AER will determine compliance with the control mechanism during the next regulatory control period.

4.1 AER draft decision

The AER accepted the Qld DNSPs' proposals to apply a revenue cap form of control to their standard control services for the next regulatory control period.

The AER required the Qld DNSPs' annual pricing proposals to include proposed tariffs and charging parameters which result in expected revenues consistent with the maximum allowed revenue (MAR) formula plus any adjustment needed to set the balance of their distribution use of system (DUOS) unders and overs account to zero (or the agreed tolerance level).

The AER also stated that in their annual pricing proposals, the Qld DNSPs must demonstrate that their proposed DUOS prices for the next year will comply with the side constraints formula for each tariff class. Ergon Energy must also demonstrate compliance with the individual side constraints for a small group of customers not yet paying cost reflective prices.[44]

4.2 Revised regulatory proposals

4.2.1 Energex

Energex resubmitted its proposal for a capital contribution bank. It provided confidential information concerning the scope for significant differences between forecast and actual capital contributions over the next regulatory control period.[45]

Energex did not raise any further matters in its revised regulatory proposal regarding the control mechanism for standard control services as outlined in the draft decision.

4.2.2 Ergon Energy

Ergon Energy accepted the control mechanism for standard control services. However, it sought clarification from the AER on the:[46]

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[43] AER, *Final decision, Framework and approach paper: Classification of services and control mechanism – Energex and Ergon Energy 2010–15*, August 2008.
[44] The details of these side constraints are confidential.
[45] Energex, *Revised regulatory proposal*, January 2010, confidential version, pp. 45–46.

- application of the DUOS unders and overs account
- inflation rate to be applied to the revenue cap
- definitions and terminology used for the MAR and side constraints formulas
- nature and application of the ring–fencing arrangements and compliance reporting
- treatment of solar bonus scheme tariffs (feed–in tariffs – FiT) and unfunded shared network events.

Application of the DUOS unders and overs account

Ergon Energy noted that under the current arrangements, it applied revenue adjustments for approved pass throughs, under/over recoveries related to capital contributions, under/over recoveries related to use of shared network and under/over recoveries related to DUOS charges.[47]

Ergon Energy explained that the sum of these adjustments was used by the QCA to determine if the annual tolerance limit had been exceeded, requiring the resultant unders/overs account balance to be reduced across multiple regulatory years (instead of cleared in the subsequent regulatory year) as agreed with QCA.[48]

Ergon Energy noted that the AER included adjustments for service target performance incentive scheme (STPIS), approved pass throughs, capital contributions and use of shared network asset in the proposed MAR calculations. With the MAR then adjusted for under/over recoveries related to DUOS charges, Ergon Energy stated that any adjustments in revenue for STPIS, approved pass throughs, capital contributions and use of shared assets will not be taken into account within the tolerance limit when clearing the DUOS unders/overs account. Ergon Energy stated continuation of the current approach should be considered by the AER as this ensures that customers do not experience price shocks.[49]

Furthermore, Ergon Energy stated that in instances where the clearing of the DUOS unders/overs account exceeds the tolerance limits, there is a need to consider not only the impact in the relevant pricing year in which adjustments are made, but also the impact in subsequent pricing years. In this regard, Ergon Energy stated that once a tolerance limit has been exceeded, if necessary, it should be the trigger to enable the DNSP to obtain AER agreement as to the most appropriate means to recover revenues in subsequent regulatory years. Ergon Energy stated that this approach would be consistent with the draft decision,[50] which indicates provision for the AER and DNSP to agree on an alternative approach.[51]

46 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 47–51.
47 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, p. 2.
48 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, p. 2.
49 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, pp. 2–4.
50 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 446.
51 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, pp. 2–4.

Ergon Energy proposed that the calculation of unders/overs should include all adjustments affecting annual revenue, including:[52]

> Revenue from billing of network charges in year t–2
>
> Revenue from capital contributions in year t–2
>
> Revenue from use of shared network by other business units in year t–2
>
> Less:
>
> Annual revenue requirement used to develop network charges in year t–2
>
> Budgeted revenue from capital contributions in year t–2
>
> Budgeted revenue from use of shared network by other business units in year t–2
>
> Plus:
>
> Any Approved Pass throughs or revenue adjustments
>
> Any revenue adjustments for STPIS.

Ergon Energy suggested that the total amount should then be adjusted to maintain the time value of money (by applying weighted average cost of capital (WACC) for 2 years) and, if it exceeds the tolerance limit of 2 per cent of the annual revenue requirement (as set down in this decision) in year t, the DNSP can obtain AER agreement to spread over 2 or more regulatory years.

Inflation rate to be applied to the revenue cap

Ergon Energy stated that a CPI factor based on March t–2 to March t–1 is not practical due to the timing of the publication of the consumer price index (CPI) for March t–1 by the Australian Bureau of Statistics (ABS). Ergon Energy noted that the ABS is intending to release the CPI for March 2010 on 28 April 2010 and it expects that similar timing will apply in future years. As Ergon Energy's pricing proposal is due for submission to the AER by 30 April in each year (except 2010), Ergon Energy considered that this would not allow it sufficient time to prepare its pricing proposal.

To ensure DNSPs are afforded sufficient time in preparing their pricing proposals, Ergon Energy proposed that the inflation rate be based on December t–2 to December t–1 CPI.[53]

Definitions and terminology used in the MAR and side constraint formulas

Ergon Energy requested clarity regarding the terms allowed revenue, MAR and revenue cap. Ergon Energy's interpretation of these terms was:[54]

> The 'AR' is the annual revenue requirement with adjustments for changes in inflation and the X factor. The 'AR' is then adjusted for Ergon Energy's performance against the STPIS, under/over recoveries in capital

[52] Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, pp. 3–4.
[53] Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, p. 2.
[54] Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, p. 1.

> contributions, under/over recoveries in transitional factors (including use of shared assets used for purposes other than standard control services) and approved pass throughs (including Solar Bonus Scheme / feed-in-tariff payments) and this is called 'MAR'; and
>
> The 'MAR' is then adjusted for any under/over recoveries related to DUOS charges (required to move the DUOS unders & overs account to zero) and this is called the 'Revenue Cap' (for any given regulatory year).

Ergon Energy accepted the draft decision to include annual adjustments for STPIS, capital contributions, pass throughs, actual tax and the treatment of shared assets in the MAR formula. However, Ergon Energy considered that the AER should review its terminology used in the definitions of these factors. In particular, Ergon Energy was concerned that it was unclear when factors were to be expressed in percentage or dollar (incremental revenue) terms. In addition, Ergon Energy believed that more detail was required to clarify precisely how the various factors are intended to be derived in complying with the formula:[55]

> For example, is an adjustment factor merely intended to represent a percentage of the AR (adjusted for inflation and the X factor) for a particular regulatory year? Or is some other calculation required?

Ergon Energy accepted the draft decision to adopt a formula for calculation of side constraints that reflected STPIS, capital contributions unders and overs, transitional factors, pass throughs and DUOS unders and overs. However, Ergon Energy again sought clarity on how the factors in the side constraint formula should be interpreted.[56]

Nature and application of the ring–fencing arrangements and compliance reporting

Ergon Energy accepted the draft decision to adopt the QCA's *Ring–Fencing Guidelines*. However, Ergon Energy sought confirmation that the ring–fencing waivers granted by the QCA would continue to apply.

Ergon Energy stated that it was in general agreement with the AER's interpretation of the *Ring–Fencing Guidelines* requirement that the QCA's *Regulatory Reporting Guidelines* are to remain in force until such time as they are replaced by any new regulatory reporting guidelines issued by the AER.

However, Ergon Energy noted that the current guidelines were developed by the QCA to allow it to perform its functions as a jurisdictional regulator. Ergon Energy suggested that the reporting guidelines should be amended to reflect the regulatory framework under the NEL and NER and in reporting back to the AER against its distribution determination for the current regulatory control period.

Ergon Energy noted the additional reporting requirements imposed in appendix Q of the draft decision. Ergon Energy proposed that, consistent with requirements for ring–fencing compliance and regulatory reporting statements, the due date for such reporting should be 31 October of each year.

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[55] Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, p. 2.
[56] Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, p. 4.

Ergon Energy was concerned with the requirement to report figures for the momentary average interruption frequency index. The AER's response to this matter is in chapter 12 of this decision.

Ergon Energy stated that it wished to consult with the AER on reporting requirements, including matters related to the development of compliance templates associated with the regulatory reporting guidelines.[57]

Treatment of feed–in tariffs and unfunded shared network events

Ergon Energy resubmitted that FiT be treated as an unders and overs factor in the revenue cap and not as a cost pass through event. Ergon Energy noted that ETSA Utilities lodged a proposed rule change with the Australian Energy Market Commission on 7 October 2009 that essentially proposed that FiT be treated as Ergon Energy proposed in its regulatory proposal. For the purposes of modelling, Ergon Energy stated that it had included a FiT forecast in its revised regulatory proposal.[58]

Ergon Energy also proposed that unfunded shared network events be a feature of the control mechanism. However, in the event that the AER declined to treat unfunded shared network events in this manner, Ergon Energy proposed that the AER approve a specific nominated pass through event for unfunded shared network events.[59]

4.3 Submissions

Energex raised three matters concerning the control mechanisms:[60]

- terminology – Energex sought confirmation that:
  - the smoothed annual revenue requirement (expected revenues) in table 16.10 of the draft decision were equivalent to the allowed revenue in the MAR formula
  - the forecast capital contributions used in the MAR and side constraints formulas were those contained in the post–tax revenue model (PTRM).
- the period over which CPI should be determined – Energex supported Ergon Energy's position in its revised regulatory proposal that a CPI based on the year to December t–1 should be used. However, Energex proposed that the roll forward of its regulatory asset based for the current regulatory period should be based on a CPI for the year to March t–1, as is its current regulatory approach.
- operation of the DUOS and transmission use of system (TUOS) unders and overs accounts – Energex noted:
  - in the DUOS unders/overs account, the interest charge on the opening balance in year t–2 did not take in to account the tolerance limits and the possibility that the opening balance in year t–2 may be older than two years

57 Ergon Energy, *Revised regulatory proposal,* January 2010, pp. 49–50.
58 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 50.
59 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 206.
60 Energex, *Submission on draft determination*, February 2010, pp. 32–35.

- in both unders and overs accounts, any under/over recoveries previously approved by the regulator for year t–2 had not been taken into account
- alternative examples of DUOS and TUOS accounts.

Energex sought clarification of how certain words and phrases in the ring–fencing guidelines should be interpreted from 1 July 2010. For example, Energex suggested that ‘prescribed distribution services’ in clause 3 of the guidelines should be interpreted as ‘standard control services’. It presented a table with revised interpretations of other words and phrases.[61]

4.4 Issues and AER considerations

4.4.1 Capital contribution bank

The AER reviewed the information provided by Energex regarding its proposal for a capital contribution bank. This information contained no new arguments to support Energex’s case but discussed the issue of the significance of the divergence between forecast and actual capital contributions. The AER considers that this information does not justify a departure from its draft decision on this matter. The draft decision outlined the AER’s reasoning, in particular:

- Energex’s concern regarding annual over/under adjustments for capital contributions is based on its expectation that actual capital contributions will consistently exceed forecast. The AER noted that, if actual contributions are less than forecast, by Energex’s own logic, it would benefit from annual adjustments (that is, under recoveries would be returned to Energex but the asset base would still be based on the higher forecast capital contribution amounts).
- The AER considered that Energex’s assumed trend of over recoveries is questionable. While the trend expected by Energex has been observed in the past, the AER expected that Energex’s experience in this regard should have assisted it in preparing more accurate forecasts of capital contributions for the next regulatory control period.
- If Energex is correct regarding the future trend of capital contributions, banking the over recoveries until the end of the next regulatory control period could lead to a significant cumulative over recovery at the start of the 2015–20 regulatory control period. The AER considered that such an adjustment would lead to more significant price adjustments than the current approach of reconciling on an annual basis. A P_0 adjustment, as proposed by Energex, would not be desirable in such circumstances. The possibility of a large cumulative unders/overs adjustment was acknowledged by Synergies Economic Consulting (Synergies). The AER considered Synergies’ suggested solution to such a possibility, namely to spread the adjustment over the 2015–20 regulatory control period, is not desirable. The Synergies’ proposal would mean that, depending on the year in which the under/over recovery emerged, it could take up to ten years for the under/over recoveries to be reconciled in full.

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[61] Energex, *Submission on draft determination*, February 2010, p. 31.

- The core of Energex's concern with annual under/over adjustments related to capital contributions appears to be the approach used to account for capital contributions and the timing of cash inflows and outflows related to these contributions. The AER noted that Energex does not need to include capital contributions in its regulatory asset base (RAB), and if it did not, it would avoid the need for any revenue adjustments. However, Energex has chosen to include capital contributions in its RAB and this decision necessitates offsetting revenue adjustments and unders/overs adjustments.

The AER considers the reasoning outlined in the draft decision remains valid. Instead, an annual adjustment to the MAR for under/over recovery of capital contributions against forecast will be made, as outlined in the draft decision. The AER notes that Ergon Energy did not object to this approach. The AER also notes that, because the unders/overs adjustment related to capital contributions is included as part of the MAR formula, any such under/over recoveries will effectively be subject to the tolerance limits of the DUOS unders and overs account.

4.4.2 DUOS unders and overs account

Ergon Energy considered that the various annual revenue adjustments (cost pass throughs, rewards/penalties associated with STPIS, under/over recoveries of capital contributions, under/over recoveries of the use of shared assets and the transitional factors) in the MAR formula should be included in the tolerance limits to apply to the DUOS unders and overs account.[62]

The AER does not agree with Ergon Energy that the tolerance limits apply to all the annual adjustment factors set out in the MAR formula. In this regard, the AER makes the following observations:

- The AER understands that the QCA would revise the Qld DNSPs' revenue requirement annually for any cost pass throughs. Revenues received by Ergon Energy were then assessed against this revised revenue requirement. Accordingly, the cost pass throughs were not subject to any tolerance limit as suggested by Ergon Energy. The AER also understands that the QCA may have smoothed the profile of cost recovery of certain cost pass throughs, but this does not mean that pass throughs were part of the tolerance limits.

- The STPIS (S_t) factor was not part of the QCA's tolerance limits as it was not a feature of the regulatory regime administered by the QCA. The AER considers that the full and immediate effect of any penalty or reward regarding service quality performance should be felt by a DNSP, thus preventing the incentive properties of the scheme from being diminished by cash flow timing issues.[63]

- The AER considers that, in regard to under/over recoveries associated with capital contributions, inclusion of the net difference between the forecasts for these items

62 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment: RP936c, pp. 2–4.

63 Even though the amount of penalty/reward under the STPIS is indexed by WACC under Ergon Energy's proposed approach, there may still be a reduction in the incentive properties of the scheme if the approach encourages an attitude that the consequences of service quality performance can be dealt with in the future, perhaps when other offsetting factors will apply.

contained in the PTRM and the subsequent actual outcomes directly into the MAR formula, means that these factors will effectively be included in the tolerance limits. Any under/over recovery associated with these factors will require the DNSP (other things being equal) to adjust its DUOS charges to reverse the under/over recovery in question.

Ergon Energy also questioned how the tolerance limits to DUOS under/over recoveries would apply. In section 4.5.2.1 of the draft decision, the AER accepted Energex's proposal to continue to apply the tolerance limits based on those approved by the QCA. These limits were detailed in section 4.3.1.2 of the draft decision. However, the AER appreciates that the statement referred to by Ergon Energy in appendix D, as to how the tolerance limits would operate, may be confusing. For the sake of clarity, the AER has restated the tolerance limits as follows:

If the DUOS under/over recoveries compared to the MAR for year t are:

- less than 2 per cent, the DUOS under/over recovery will be cleared within one regulatory year

- between 2 per cent and 5 per cent, the DUOS under/over recovery can be spread over two regulatory years

- greater than 5 per cent, the DNSP must submit a plan to the AER detailing how it proposes to clear the balance of the DUOS unders and overs account.

In appendix D of the draft decision, the AER set out how the Qld DNSPs should compare the revenues it received from DUOS charges with the MAR for any given year to determine the size of any DUOS under/over recoveries. This appendix has been revised to clarify a number of matters, including:

- in the example in table D.1 the components of the MAR formula have been expanded. The definitions of these components are contained in the MAR formula presented in the AER conclusion section below.

- an additional term has been added to the DUOS unders and overs account to recognise any over/under adjustments that were previously approved by the regulator in year t–2. This addition was necessary to prevent, for example, incremental revenues to be recovered from customers in year t, due to an under recovery in year t–2, appearing as an over recovery in a further two years time. A similar term has also been added to the TUOS unders and overs account in appendix E for the same reason.

- a note has been added to appendix D to clarify that any opening balance on the DUOS unders and overs account must be fully indexed by WACC up to the beginning of year t–2. As presented in the draft decision, the calculation gave the impression that any over/under recoveries related to years before year t–2 would only be indexed by WACC for two years. The AER notes that it highly unlikely that there would be a balance on the DUOS unders and overs account that was more than two years old. Such a balance will only occur where the tolerance limits had previously been invoked.

The AER decided not to use the examples suggested by Energex for the DUOS and TUOS under and over accounts. However, the AER has addressed the concerns raised by Energex and provided amended examples of the DUOS and TUOS unders and overs accounts in appendices D and E.

4.4.3 Definition of CPI

The AER considers that the inflation measure used in the control mechanism should be as up to date as possible. The AER also considers that it is desirable to have consistency between the CPI used for the roll forward of the asset base for the current regulatory period (which was based on the year to March t–1) and the CPI used for determining the MAR going forward. Against these general propositions, the AER has considered Ergon Energy's and Energex's proposals that the use of a CPI based on the year to March t–1 in the MAR formula would hamper their ability to prepare their pricing proposal in a timely manner.

The AER does not agree with the Qld DNSPs' assertion and considers that they should be able to prepare their pricing proposal using a forecast CPI. If the proposal is prepared while bearing in mind that the CPI figure will be updated at the last moment, the AER considers that the updating of prices should be a straight forward matter. The AER notes that the CPI adjustment affects all tariffs by the same proportion, so there should be no allocation issues across the tariff classes to complicate such an update. The calculation of the MAR for Energy Australia's transmission services uses a CPI based on the year to March t–1,[64] while ETSA Utilities, in its revised regulatory proposal, has proposed that the CPI factor in its weighted average price cap be based on the year to March t–l.[65] ETSA Utilities pricing proposal is subject to the same timelines as the Qld DNSPs.

Notwithstanding the above, if circumstances required, the AER would consider accepting from a DNSP a provisional pricing proposal, subject to the CPI figure being updated during the time set for the AER's assessment of the proposal.

4.4.4 Definition and terminology issues

Ergon Energy's interpretation of the allowed revenue and MAR is consistent with the way the AER intended for these to be interpreted. Ergon Energy's interpretation of the term revenue cap is also consistent with the AER's use of the term in the draft decision. Each year a DNSP's revenues will be capped by the MAR for the relevant year plus/minus any DUOS under/over recoveries to be recovered from (returned to) customers.

Regarding Energex's understanding that the expected revenues (as presented in table 16.10 of the draft decision) are equivalent to the allowed revenues in the MAR formula, the AER confirms that this is correct for the first year of the next regulatory control period. However, for subsequent years, the expected revenues presented in this decision are unlikely to match the allowed revenues, as inflation is likely to differ from that forecast in this decision. Allowed revenues are to be recalculated annually

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[64] AER, *Final Decision, New South Wales distribution determination 2009–10 to 2013–14,* 28 April 2009, p. 64.

[65] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 36.

based on actual inflation and the same X factors used to determine the expected revenues in this decision.

Ergon Energy queried when percentages or dollars should be used in the control mechanism formulas. For the allowed revenue formula, the CPI factor and the X factor are in percentage terms (with the latter derived from the PTRM). However, as these factors are applied to the allowed revenue derived from the PTRM in dollar terms, the results of the annual calculation of allowed revenue is in dollar terms. For the MAR, all the factors (that is, allowed revenue, the pass through factor, the transitional factor, the capital contributions unders/overs factor and the STPIS factor) are in dollar terms.

In contrast, the factors in the side constraint formula must ultimately be assessed in percentage terms as the intention of the constraint is to limit the degree of change in the prices of individual tariff classes from one year to the next. The CPI and X factors will be those percentages used in the MAR formula. The percentages for each of the other factors can be calculated by dividing the incremental revenue (as set out in the MAR formula) for each factor by the expected revenues for year t–1 (based on the prices in year t–1 multiplied by the forecast quantities for year t). Such a calculation implicitly assumes an even allocation of costs across tariff classes.

However, there may be cases where it would be more consistent with the pricing principles contained in the NER (in particular the requirement that prices are between standalone and avoidable costs[66]) for certain costs to be recovered from a particular tariff class only or in varying proportions across tariff classes. In such circumstances, the side constraints may differ by tariff class. For example, the AER may approve a cost pass through that applies only to a particular group of customers. In such circumstance, the side constraint applied only to this group of customers would be relaxed due to the cost pass through, while the side constraint for the other customer groups would be unaffected by this particular pass through. The AER would expect a DNSP to include, as part of any cost pass through application, a proposal on how the costs are to be recovered across different tariff classes.

The AER has added additional detail to deriving the various factors contained in the MAR and side constraint formulas to address the terminology concerns of the Qld DNSPs. This detail is contained in the revised definitions to the MAR and side constraint formulas presented in section 4.5 of this decision.

4.4.5 Application of the side constraints

The AER considers the side constraints contained in this decision do not apply for the first year of the next regulatory control period. This issue was not discussed in the draft decision but reflects the application of side constraints for the approval of prices of the NSW and ACT DNSPs for the first year of their current regulatory control period. The AER considers clause 6.18.6(b) of the NER has the effect of preventing the side constraints from applying between the regulatory control periods. Accordingly, the prices for 2009–10 cannot be used a basis for applying the side constraints. The side constraint formula set out in section 4.5 is intended to first apply

66 NER, clause 6.18.5(a).

to the prices for 2011–12, when these prices will be compared against the prices for 2010–11.

4.4.6 Ring–fencing and compliance monitoring

In response to Ergon Energy, the AER confirms that the ring–fencing waivers granted by the QCA will continue to apply during the next regulatory control period.

The AER acknowledges that the reporting guidelines developed by the QCA will require some refinement to better reflect the regulatory framework under the NEL and NER. The AER will engage with the Qld DNSPs on how certain words and phases in the guidelines (including those phrases highlighted by Energex in its submission on the draft decision) should be interpreted going forward. The AER also intends to review the reporting requirements during the next regulatory control period and will consult with the Qld DNSPs over any changes to the reporting requirements, including the development of compliance templates.

The AER accepts Ergon Energy's proposal that, consistent with the requirements for ring–fencing compliance and the regulatory reporting statements, the Qld DNSPs submit the information noted in appendix L to the AER by 31 October each year.

4.4.7 Feed–in tariffs

The AER considers that the FiT scheme is a cost that stems from complying with a regulatory obligation. The costs of complying with regulatory obligations are permitted to be included in forecast opex under clause 6.5.6(a)(2) of the NER. Consequently, the AER does not consider that FiT costs should be included in the control mechanism without being included in the building blocks, as Ergon Energy has proposed to do.

The AER acknowledges that the costs associated with FiT may be difficult to forecast reliably as it is a relatively new regulatory obligation. Consequently, the AER considers that, while FiT costs should be included in the building blocks as forecast opex, for the next regulatory control period, it is appropriate that any differences between forecast and actual FIT costs be adjusted by way of a cost pass through mechanism. This approach was set out in the draft decision and is a feature of recent AER determinations for electricity distribution business in NSW[67] and the ACT.[68] In considering the proposal of Ergon Energy to include FiT costs in the control mechanism, the AER also considers that it is desirable that FiT schemes in different jurisdictions should be treated in a consistent manner, consistent with section 6.2.5(c)(4) of the NER.

The FiT cost pass through mechanism is discussed in chapter 15 of this decision.

4.4.8 Unfunded shared network events

When Ergon Energy connects a large customer to its network there will be dedicated assets associated with its connection. The AER has previously decided (and Ergon Energy accepted) that these dedicated asset costs be treated as alternative control

[67] AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 56.
[68] AER, *Final decision, ACT distribution determination*, 28 April 2009, p. 17.

services.[69] However, when a large customer connects, it also makes use of (or requires an upgrade to be made to) shared assets (for example, the main trunk lines). As part of its capex forecasts, Ergon Energy included growth capex related to an expected number of new connections over the next regulatory control period. Ergon Energy is seeking to have a factor added to the control mechanism for any unanticipated large customer connections that may occur during the next regulatory control period and that create unfunded shared network costs.

The AER does not consider it appropriate to simply include an additional factor in the control mechanism for unfunded shared network costs and rejects Ergon Energy's proposal to do so. The AER notes that:

- it is not consistent with the incentive properties of a revenue cap for additional costs to be simply passed through for unexpected network growth. For example, while Ergon Energy forecast a number of large customer connections over the next regulatory control period, some of these connections may well not proceed. In such circumstances, any underspend will be reflected in the roll forward of the asset base at the end of the regulatory control period, not clawed back within period

- any unexpected projects will not be subject to same level of scrutiny as those put forward as part of a regulatory proposal

- it is not a straight forward matter to separate shared network costs from the dedicated asset costs. The AER would not wish to create an incentive for dedicated asset costs to be simply labelled as shared network costs. Such an outcome could reduce competition in the alternative control service of large customer connections, as the costs at which Ergon Energy could deliver this service may be cross subsidised by payments received for standard control services.

In the event that the AER rejected Ergon Energy's proposal for unfunded shared network events to be part of the control mechanism, Ergon Energy requested that unfunded shared network events be treated as a cost pass through event. This proposal is discussed in chapter 15 of this decision.

4.5 AER conclusion

As part of their pricing proposals, the Qld DNSPs must submit to the AER proposed tariffs and charging parameters which lead to expected revenues consistent with the MAR formula set out below plus any unders and overs adjustment needed to move the balance of their DUOS unders and overs account to zero (subject to the tolerance limits).

4.5.1 Maximum allowable revenue formula

The MAR is determined annually by adding to, or subtracting from, the allowed revenue any STPIS revenue increment (or revenue decrement), any unders/overs

[69] AER, *Final framework and approach paper: Classification of services and control mechanism*, August 2008.

adjustments related to capital contributions, certain transitional adjustments and any approved pass through amounts, as follows:

$$MAR_t = AR_t \pm S_t \pm C_t \pm transitional_t \pm passthrough_t$$

where:

t is the regulatory year

MAR_t is the maximum allowed revenue for each year of the next regulatory control period

AR_t is the allowed revenue for regulatory year t. For the first year of the next regulatory control period, this amount will be equal to the smoothed revenue requirement for 2010–11 set out in the PTRM approved by the AER. The subsequent year's allowed revenue is determined by adjusting the previous year's allowed revenue for actual inflation and the X factor:

$$AR_t = AR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$$

where:

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in year t–2 to March in year t–1

X_t is the X factor for each year of the next regulatory control period as determined by the PTRM.

S_t is the STPIS factor sum of the raw s-factors for all reliability of supply and customer service parameters (as applicable) to be applied in regulatory year t[70]

C_t is the annual adjustment factor related to capital contributions and is determined by subtracting from the forecast capital contributions for year t–2 contained in the PTRM, the actual capital contributions received by the DNSP in year t–2. The amount so calculated is then to be indexed for two years by the nominal rate of return

$transitional_t$ is a transitional factor for matters such as unders and overs in tax paid during the current regulatory control period and unders and overs adjustments related to standard shared assets used for purposes other than standard control services. The size of these annual adjustments will also be calculated by subtracting from forecasts, the actual revenues received in

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70 The formula is set out in AER, *Final decision, Electricity distribution network service providers, Service target performance incentive scheme*, November 2009, pp. 32–33.

year t–2.[71] The amounts so calculated are then to be indexed for two years by the nominal rate of return

$passthrough_t$ is the approved pass through amounts with respect to regulatory year t, as determined by the AER.

4.5.2 Side constraints

In their pricing proposals, the Qld DNSPs will be required to demonstrate that their proposed DUOS prices for the next year (t) will meet the following side constraints formula (expressed in percentage terms) for each tariff class:

$$\frac{\sum_{j=1}^{m} d_t^j \times q_t^j}{\sum_{j=1}^{m} d_{t-1}^j \times q_t^j} \leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%) \pm S_t \pm C_t \pm transitional_t \pm passthrough_t \pm unders\ \&\ overs_t$$

where each tariff class 'j' has up to 'm' components, and where:

d_t^j is the proposed price for component 'j' of the tariff class for year t

d_{t-1}^j is the price charged by the DNSP for component 'j' of the tariff class in year t–1

q_t^j is the forecast quantity of component 'j' of the tariff class in year t

ΔCPI_t is the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in regulatory year t–2 to March in regulatory year t–1

X_t is the X factor for each year of the regulatory control period. If X>0, then X will be set equal to zero for the purposes of the side constraint formula

S_t is the STPIS factor to be applied in regulatory year t

C_t is the annual adjustment factor for the difference between forecast and actual capital contributions in year t–2

$transitional_t$ is a transitional factor for matters such as unders and overs in tax paid during the current regulatory control period and unders and overs adjustments related to shared assets used for purposes other than standard control services

[71] In terms of the actual use of shared assets for purposes other than standard control services, Ergon Energy should continue to calculate this amount consistent with the approach used for reporting to the QCA and as outlined in its regulatory proposal (Ergon Energy, *Regulatory proposal to the AER, Distribution services for the period 1 July 2010 to 30 June 2015*, July 2009, p. 377). As noted in the draft decision (AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 34), no unders/overs adjustment in relation to this matter is required by Energex.

passthrough$_t$ is an annual adjustment factor that reflects the pass through amounts approved by the AER with respect to regulatory year t

unders&overs$_t$ is an annual adjustment factor related to the balance of the DUOS unders and overs account with respect to regulatory year t.

With the exception of the CPI and X factors, the percentage for each of the other factors above can be calculated by dividing the incremental revenues (as used in the MAR formula) for each factor by the expected revenues for regulatory year t–1 (based on the prices in year t–1 multiplied by the forecast quantities for year t).

In addition, Ergon Energy must continue to comply with the individual side constraints set out for those customers listed in table 143 (confidential) of its regulatory proposal.

4.5.3 Ring–fencing and compliance monitoring

Clause 11.14.5(b)(3) of the NER states that ring–fencing guidelines in force in a participating jurisdiction immediately before the AER's assumption of regulatory responsibility (transitional guidelines) continue in force for that jurisdiction. The QCA *Ring–fencing guidelines* are therefore applicable transitional guidelines for Queensland.[72] Consistent with clause 11.14.5(c) of the NER these transitional guidelines will be regarded as the AER's guidelines and any reference to the jurisdictional regulator will be considered a reference to the AER until amended, revoked or otherwise replaced by the AER.

The transitional guidelines set out specific requirements in regard to:

- legal separation of entities
- definition of related businesses
- accounting and auditing requirements, cost allocation
- information flows to related businesses
- ring–fencing waivers
- procedures for revising the guidelines.

Cost allocation methods prepared by the Qld DNSPs that are to be applied in the next regulatory control period were approved by the AER in February 2009.

The QCA stated that a DNSP is required to demonstrate compliance and its compliance report must identify the policy, state how it has been implemented and identify how the effectiveness of the policy will be monitored and/or audited.[73]

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72 QCA, *Final determination, Electricity distribution: Ring–fencing guidelines*, September 2000.
73 QCA, *Final determination, Regulation of electricity distribution*, April 2005, p. 212.

The transitional guidelines contain regulatory reporting requirements. Amongst other things, these reporting requirements provide the AER with the information that is required to ensure that distribution charges for standard (and alternative) control services are set, and have been set, in accordance with the final determination. These reporting arrangements will continue in the next regulatory control period. As such, the regulatory reporting guidelines approved by the QCA will also continue to apply.[74] The application of the reporting guidelines is an obligation of the transitional guidelines (clause 2).[75]

To the extent that the QCA's reporting guidelines do not cover additional matters addressed in this decision, such as the incentive schemes discussed in chapters 12, 13 and 14, appendix L of this decision sets out reporting requirements. This appendix should be read in conjunction with the QCA's regulatory reporting guidelines.

4.6 AER decision

In accordance with clause 6.12.1(11) of the NER, the control mechanism for standard control services provided by Energex is a revenue cap.

The revenue cap for any given regulatory year is the MAR for that regulatory year (as calculated using the formula in section 4.5.1 of this decision) plus any under/over adjustment required to move the DUOS under/over account (as set out in appendix D to this decision) to zero (subject to the tolerance limits).

The side constraints to apply to the price movements of each of Energex's tariff classes must be consistent with the formula in section 4.5.2 of this decision.

In accordance with clause 6.12.1(19) of the NER, Energex must submit, as part of its annual pricing proposal, a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with appendix E of this decision.

In accordance with clause 6.12.1(13) of the NER, Energex must demonstrate compliance with the control mechanism for standard control services in accordance with appendices D and E of this decision.

74 QCA, *Electricity distribution: Regulatory reporting guidelines*, Version 4.1, November 2005.

75 QCA, *Final determination, Electricity distribution: Ring–fencing guidelines*, September 2000, p. 21.

In accordance with clause 6.12.1(11) of the NER, the control mechanism for standard control services provided by Ergon Energy is a revenue cap.

The revenue cap for any given regulatory year is the MAR for that regulatory year (as calculated using the formula in section 4.5.1 of this decision) plus any under/over adjustment required to move the DUOS under/over account (as set out in appendix D to this decision) to zero (subject to the tolerance limits).

The side constraints to apply to the price movements of each of Ergon Energy's tariff classes must be consistent with the formula in section 4.5.2 of this decision. In addition, Ergon Energy must continue to comply with the individual side constraints set out for those customers listed in table 143 (confidential) of its regulatory proposal.

In accordance with clause 6.12.1(19) of the NER, Ergon Energy must submit, as part of its annual pricing proposal, a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with appendix E of this decision.

In accordance with clause 6.12.1(13) of the NER, Ergon Energy must demonstrate compliance with the control mechanism for standard control services in accordance with appendices D and E of this decision.

5 Opening regulatory asset base

This chapter sets out the method used by the AER to determine the closing regulatory asset base (RAB) for the Qld DNSPs for the current regulatory control period. The closing RAB for the current regulatory control period becomes the opening RAB for the next regulatory control period and is used to calculate the annual building block revenue requirements.

5.1 AER draft decision

5.1.1 Energex

The RAB roll forward calculations for Energex are set out in table 5.1 and resulted in an opening RAB of $7887 million for standard control services as at 1 July 2010. The decrease in opening RAB reflected the use of a different inflation rate from that used by Energex as well as adjustments for actual capex differences, and the exclusion of alternative control assets from the RAB.

Table 5.1: AER draft decision on opening RAB to apply to Energex ($m, nominal)

	2005–06	2006–07	2007–08	2008–09[a]	2009–10[b]
Opening RAB	4345.2	4996.7	5596.7	6248.6	7003.4
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	744.6	734.7	694.4	890.5	1048.0
Regulatory depreciation (adjusted for actual CPI)	–93.2	–134.7	–42.5	–135.7	–148.2
Closing RAB	4996.7	5596.7	6248.6	7003.4	7903.2
Difference between actual and forecast capex for 2004–05					53.1
Return on difference					27.3
Adjustment for street lighting services					–96.1
Opening RAB at 1 July 2010					7887.4

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 51.
(a) Based on estimated net capex.
(b) Based on estimated net capex and a forecast inflation rate.

No submissions were received on the opening RAB for Energex.

5.1.2 Ergon Energy

The RAB roll forward calculations for Ergon Energy are set out in table 5.2, and resulted in an opening RAB of $7105 million as at 1 July 2010.

The AER determined an opening RAB higher than that proposed by Ergon Energy due to the use of a different inflation rate than that proposed by Ergon Energy.

Table 5.2: AER draft decision on opening RAB to apply to Ergon Energy ($m, nominal)

	2005–06	2006–07	2007–08	2008–09[a]	2009–10[b]
Opening RAB[c]	4146.2	4662.4	5243.4	5858.1	6402.4
Actual net capex (adjusted for actual CPI and WACC)	622.1	720.2	654.5	686.8	833.9
Regulatory depreciation (adjusted for actual CPI)	–105.9	–139.3	–39.8	–142.4	–131.0
Closing RAB	4662.4	5243.4	5858.1	6402.4	7105.4
Opening RAB at 1 July 2010					7105.4

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 51.
(a) Based on estimated net capex.
(b) Based on estimated net capex and a forecast inflation rate.
(c) Excludes an amount of $47 million related to street lighting assets. The roll forward of this amount was discussed in chapter 17 of the draft decision.

No submissions were received on the opening RAB for Ergon Energy.

5.2 Revised regulatory proposals

5.2.1 Energex

Energex proposed a revised opening RAB of $7841.5 million as at 1 July 2010, $46.0 million less than allowed by the AER in the draft decision.

Energex maintained the same approach to determining its opening RAB as in the draft decision. The only change it made to the roll forward model (RFM) was to update capex figures for 2008–09 to actuals. Energex did not provide revised capex forecasts for 2009–10.[76]

Energex accepted the draft decision to determine its opening RAB for the 2015–20 regulatory control period using actual depreciation.[77]

5.2.2 Ergon Energy

Ergon Energy proposed a revised opening RAB of $7174.0 million as at 1 July 2010, $68.6 million more than allowed by the AER in the draft decision.

Ergon Energy maintained the same approach to determining its opening RAB as in the draft decision. It also accepted the draft decision that the roll forward of its asset base over the current regulatory control period should use CPI based on the year to March.[78]

[76] Energex. *Revised regulatory proposal*, January 2010, p. 32.
[77] Energex. *Revised regulatory proposal*, January 2010, p. 32.
[78] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 54.

However, Ergon Energy adjusted the forecast CPI figures for the current regulatory control period in its RFM. It also updated the capex figures for 2008–09 to actuals and provided revised capex forecasts for 2009–10.[79]

Ergon Energy accepted the draft decision to determine its opening RAB for the 2015–20 regulatory control period using actual depreciation.[80]

5.3 Issues and AER considerations

5.3.1 Revisions to the roll forward models

The Qld DNSPs made limited changes to their RFMs in their revised regulatory proposals. The AER accepts the Qld DNSPs' updated capex for 2008–09 due to actual outcomes. The AER also accepts Ergon Energy's revised capex forecasts for 2009–10. Compared to the draft decision, these changes have caused a reduction in Energex's opening RAB, and an increase in Ergon Energy's opening RAB.

The AER asked Energex why it had not provided a revised capex forecasts for 2009–10. The AER notes that actual capex for 2008–09 was about 4 per cent lower than had been forecast for the draft decision.[81] Energex stated that it had recently reviewed its project prioritisation and considered that, with the exception of metering capex, it was on track to achieve its capex forecast for 2009–10.[82] Energex provided a revised forecast for metering capex in 2009–10.[83] The AER has adopted this revised metering capex forecast which reflects an anticipated reduction in spending on smart meters in 2009–10. The AER notes that when the RFM is prepared for the 2015–20 regulatory control period, there will be an adjustment made for any difference between Energex's capex forecast for 2009–10 and its actual capex spend for the year. This adjustment is also indexed by the weighted average cost of capital to make sure that the DNSP is neither over nor under compensated. Based on these considerations, the AER accepts Energex's capex forecast for 2009–10 without further adjustment.

The AER asked Ergon Energy why it had adjusted the forecast CPI figures applicable to the current regulatory control period contained in its revised RFM. Ergon Energy stated that its changes only affected any adjustments made in relation to capex for 2004–05. Given that it had no adjustment to make to capex for 2004–05 (because the QCA has already determined this adjustment in a separate assessment), Ergon Energy considered it could set the forecast and actual CPIs in the RFM equal without affecting the opening RAB.[84]

The AER considers that Ergon Energy's adjustment is not correct. By leaving blank the 2004–05 capex inputs to the RFM, Ergon Energy has already achieved the appropriate effect of not requiring adjustments for the difference between forecast and actual capex for 2004–05. The forecast CPI figures are inputs to determine the annual

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79 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 14 and revised *RFM*.

80 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 54.

81 This difference was determined by comparing capex in the PTRM used for the draft decision and the revised PTRM submitted by Ergon Energy as part of its revised regulatory proposal.

82 Energex, *email to the AER: AER.EGX.RP.08*, 9 March 2010, confidential.

83 Energex, *email to the AER: Final Modelling*, 29 April 2010, confidential.

84 Ergon Energy, *email to the AER: AER.ERG.RRP.25*, 5 March 2010.

fixed real rate of return over the current regulatory control period. This real rate of return affects not just the adjustment related to the difference between forecast and actual capex for 2004–05, but also the capex incurred during the current regulatory control period. The AER therefore considers that Ergon Energy should not have changed the forecast CPI inputs in the RFM and has adjusted the RFM accordingly.

The AER observed that Ergon Energy had not provided forecasts for asset disposals for 2009–10 in its revised RFM. However, Ergon Energy included actual disposals of $46 million in 2008–09 and $52 million of disposals on average over the first four years of the current regulatory control period. While there is scope for an adjustment to be made at the next regulatory reset in the roll forward of the asset base to 1 July 2015, the AER considers that it is not appropriate for zero asset disposals to be forecast for 2009–10. If no forecast disposals for 2009–10 are included in the RFM, the adjustment at the next regulatory reset will be large. Accordingly, the AER required Ergon Energy to provide forecast asset disposals for 2009–10. Ergon Energy provided forecast disposals for 2009–10 of $37 million based on an extrapolation of six months of actual data for 2009–10.[85] The AER accepts these forecast disposals.

5.3.2 The CPI for 2009–10

As signalled in its draft decision, the AER updates the CPI figure for the final year of the current regulatory control period in the Qld DNSPs' RFMs using CPI for the year ending March 2010. This update affects the opening RABs for the Qld DNSPs for standard control and alternative control services as at 1 July 2010.

5.4 AER conclusion

5.4.1 Energex

The RAB roll forward calculations for Energex are set out in table 5.3 and provide for an opening RAB of $7867.3 million for standard control services for the next regulatory control period (as at 1 July 2010). The opening RAB for alternative control services is $96.8 million.[86]

[85] Ergon Energy, email to the AER: *AER.ERG.RRP.36*, 19 March 2010.

[86] This amount differs to that proposed by Energex in its revised regulatory proposal due to the updating of CPI for 2009–10.

Table 5.3: AER conclusion on Energex's opening RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10[a]
Opening RAB	4345.2	4996.7	5596.7	6248.6	6955.9
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	744.6	734.7	694.4	843.1	1041.5
Regulatory depreciation (adjusted for actual CPI)	–93.2	–134.7	–42.5	–135.7	–114.1
Closing RAB	4996.7	5596.7	6248.6	6955.9	7883.4
Difference between actual and forecast capex for 2004–05					53.1
Return on difference					27.7
Less: system assets moving from standard control services to alternative control services					–96.8
Opening RAB at 1 July 2010					7867.3

Note: (a) Based on estimated net capex.

5.4.2 Ergon Energy

The RAB roll forward calculations for Ergon Energy are set out in table 5.4 and provide for an opening RAB of $7148.9 million for standard control services for the next regulatory control period (as at 1 July 2010).

Table 5.4: AER conclusion on Ergon Energy's opening RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10[a]
Opening RAB	4146.2	4662.4	5243.4	5858.1	6452.6
Actual net capex (adjusted for actual CPI and WACC)	622.1	720.2	654.5	737.0	819.5
Regulatory depreciation (adjusted for actual CPI)	–105.9	–139.3	–39.7	–142.4	–123.2
Closing RAB	4662.4	5243.4	5858.1	6452.6	7148.9
Opening RAB at 1 July 2010					7148.9

(a) Based on estimated net capex.

5.5 AER decision

In accordance with clause 6.12.1(6) of the NER the total opening asset base for Energex as at 1 July 2010 is $7971.0 million, consisting of $7867.3 million for standard control services and $96.8 million for alternative control services.

In accordance with clause 6.12.1(6) of the NER the opening asset base for Ergon Energy as at 1 July 2010 is $7148.9 million.

In accordance with clause 6.12.1(18) of the NER, the AER has decided to use actual depreciation for establishing the regulatory asset base at the commencement of the 2015–20 regulatory control period.

6 Demand forecasts

This chapter sets out the AER's consideration of the Qld DNSPs' maximum demand, customer number and energy forecasts for the next regulatory control period. The AER considers the extent to which the forecasts can be relied upon for the purposes of assessing the proposed load driven capex.

6.1 AER draft decision

Energex

The AER accepted Energex's forecasts of customer numbers and energy consumption.[87]

The AER considered the maximum demand forecasts proposed by Energex did not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives. The AER considered that reducing Energex's forecast maximum demand to the levels shown in table 6.1 provided a more realistic basis for determining capex and opex forecasts.

Table 6.1: AER draft conclusion on Energex's maximum demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15
Maximum demand (MW)	4864	5027	5228	5466	5684
Customer numbers	1 363 138	1 389 033	1 417 664	1 448 548	1 480 294
Energy consumption (GWh)	22 416	23 138	24 042	24 795	25 845

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 80.

Ergon Energy

The AER accepted Ergon Energy's forecasts of customer numbers.[88]

The AER considered the maximum demand and energy consumption forecasts proposed by Ergon Energy did not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives. The AER considered that reducing Ergon Energy's forecast maximum demand to the levels shown in table 6.2 provided a more realistic basis for determining capex and opex forecasts.

[87] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 80.
[88] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 80.

Table 6.2: AER draft conclusions on Ergon Energy's maximum demand and customer number forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15
Maximum demand (MW)	2693	2811	2928	3031	3121
Customer numbers	684 469	695 242	706 204	717 356	728 706

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 81.

The AER noted that energy consumption forecasts are not relevant in the determination of Ergon Energy's revenue cap. However, energy consumption forecasts are an important input to the development of Ergon Energy's network prices. The AER required Ergon Energy to review its energy consumption forecasts before submitting its pricing proposal to the AER for approval in 2010.[89]

6.2 Revised regulatory proposals

6.2.1 Energex

6.2.1.1 System maximum demand

Energex disagreed with the draft decision to adopt McLennan Magasanik Associates' (MMA) alternative system maximum demand forecast in place of the forecast contained in its regulatory proposal.

Energex noted that MMA's system maximum demand growth projection of 1066 MW over the next regulatory control period was similar to Energex's own forecast of 1034 MW. However, Energex believed MMA's alternative system maximum demand forecast methodology, which the AER accepted in the draft decision, was flawed.[90]

Energex considered MMA's alternative demand forecast model to have the following limitations:[91]

- there was no methodological justification for using 2006–07 as the starting point of the analysis over another year
- the starting point (2006–07) for MMA's analysis understated the initial value for the 2008–09 50% probability of exceedence (PoE) maximum demand
- the model ignores the changes in temperature sensitive load and the impact of those changes
- there was no supporting information provided on the calculation of the lower range for maximum demand
- MMA has misinterpreted Powerlink's *2009 Annual Planning Report* data.

89 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 79–80.
90 Energex, *Revised regulatory proposal*, January 2010, p. 5.
91 Energex, *Revised regulatory proposal*, January 2010, pp. 5–6.

Energex noted that both the AER and Energex based their proposed adjustments to the forecast growth capital expenditure program on a scaling of the program using the system maximum demand forecast. On this basis, Energex provided an updated system maximum demand forecast in the revised proposal to validate its proposed growth capex.[92]

Energex stated that its revised system maximum demand forecast was based on an updated economic outlook produced by the National Institute of Economic and Industrial Research (NIEIR). It advised that the forecast level of system maximum demand over the next regulatory control period aligns closely with Energex's original forecast contained in its regulatory proposal.[93]

Energex further submitted that it considered:[94]

> the NIEIR forecast is an independent and robust forecast that does not rely on adjusting the starting value for 50 PoE demand, is the most up to date forecast, and will provide a realistic expectation of the forecast demand to achieve the capital expenditure and operating expenditure under the Rules.

Energex's original system maximum demand forecast submitted as part of its regulatory proposal, and its revised forecast are presented in table 6.3.

Table 6.3: Energex's maximum demand forecasts including demand management initiatives (MW)

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15[a]
Energex original forecast	5126	5338	5633	5844	5941	3.8%
Energex revised forecast	5118	5376	5655	5814	5940	3.8%
AER draft decision forecast	4864	5027	5228	5466	5684	4.0%

Source: Energex, *Revised regulatory proposal*, January 2010, p. 10.
(a) Average annual growth rate calculated based on 2010–11 to 2014–15 data.

6.2.1.2 Customer numbers and energy consumption

Energex accepted the draft decision that its proposed customer numbers and energy consumption forecasts provided a realistic expectation of demand forecast required to achieve the capex and opex objectives.[95]

92 Energex, *Revised regulatory proposal*, January 2010, p. 4.
93 Energex, *Revised regulatory proposal*, January 2010, p. 10.
94 Energex, *Revised regulatory proposal*, January 2010, p. 10.
95 Energex, *Revised regulatory proposal*, January 2010, p. 5.

6.2.2 Ergon Energy

6.2.2.1 Spatial and system maximum demand

Ergon Energy disagreed with the draft decision not to accept its maximum demand forecast.[96]

Ergon Energy stated that it considered its forecasting approach and methodology to be consistent with sound electricity industry practice, and that it believes the AER and MMA have not provided sufficient reasons or evidence that it should adopt the approach outlined by the AER in its draft decision.[97]

In response to issues raised in the draft decision in relation to its maximum demand forecast methodology and forecasts, Ergon Energy:[98]

- provided further supporting information to demonstrate that it has adequately reconciled its bottom up forecasts with the econometric forecasts produced by NIEIR
- provided further supporting information to demonstrate that its spot load forecasting process is reliable and prudent. In particular, Ergon Energy considered that the process has ensured valid decisions are made about the timing of future spot loads, and that no future loads are double counted
- engaged Evans & Peck to provide a review of Ergon Energy's 2009 maximum demand forecast.

Ergon Energy considered that MMA's alternative system maximum demand forecast methodology, which the AER accepted in its draft decision, is flawed. Ergon Energy considered MMA's analysis had the following key limitations:[99]

- MMA's top down forecast was based on out of date historical and forecast gross state product (GSP) data
- MMA's forecasting model did not include variables that differentiate the south east Queensland dominated state product from regional Queensland product
- it is inappropriate to rely on Queensland GSP as a proxy for growth in regional Queensland given its higher exposure to the rapidly recovering Asian export markets.

Ergon Energy provided a revised maximum demand forecast based on both updated bottom up and top down forecasts produced by Ergon Energy and NIEIR respectively. Ergon Energy stated that it has reconciled its bottom up demand forecast with NIEIR's top down system demand forecast, which were both produced in December 2009. Ergon Energy advised that apart from the first year of the regulatory

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[96] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 68.
[97] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 78–80.
[98] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 78–80.
[99] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 79.

control period, its revised forecast aligns closely with the original forecast contained in its regulatory proposal with differences in each year less than one per cent.[100]

Ergon Energy's system maximum demand forecasts submitted as part of its regulatory proposal, and its revised forecasts are presented in table 6.4.

Table 6.4: Ergon Energy 50% PoE system maximum demand forecast (MW)

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15[a]
Original forecast	2967	3063	3153	3243	3330	2.9%
Revised forecast	2807	3052	3181	3282	3365	4.7%

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, p. 83.
Note: (a) Average annual growth rate calculated based on 2010–11 to 2014–15 data.

6.2.2.2 Customer numbers and energy consumption

Ergon Energy accepted the draft decision that its proposed customer numbers provided a realistic expectation of the demand forecast required to achieve the capex and opex objectives.

Ergon Energy did not accept the draft decision on its proposed energy consumption forecast and provided a revised energy consumption forecast which is identical to its original forecast, is shown in table 6.5.[101]

Table 6.5: Ergon Energy revised energy consumption forecast (GWh)

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15
Revised forecast	15 871	16 450	16 874	17 433	17 887	3.0%

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, p. 83.

6.3 Submissions

Powerlink submitted that the AER's demand forecasts may not match what is being seen on the ground, as physical demand growth may not be reflected in the monetary measure of GSP. Powerlink considered that while in many instances the dollar value was a useful proxy, it may not be the case in the current circumstances. It cited a recent Qld economic report which showed over the past 12 months coal and minerals prices had fallen by about 48 per cent, which would drag down the GSP despite underlying levels of physical activity. Powerlink suggested that since the global financial crisis (GFC) began, despite an initial fall in mining activity, export volumes had rebounded, but this increased activity would not show in measures of GSP as

[100] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 80.
[101] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 82.

commodity prices had fallen significantly. Powerlink also suggested that the GFC had not affected population growth in Queensland, and believed that this needed further consideration by the AER and its consultants.[102]

Powerlink also questioned how the prospect of an Emissions Trading Scheme (ETS) should be factored into the demand forecasts, given its uncertainty. Powerlink noted that there were other factors such as compensation schemes for low income families, and the Commonwealth Scientific and Industrial Research Organisation forecast of rising summer temperatures, which may offset any possible reduction in demand due to the ETS. Powerlink suggested that picking one factor and applying it was problematic, and that the AER should either ignore the effects of any possible ETS or it should model the other factors it noted.[103]

6.4 Consultant review

The AER engaged MMA to provide assistance in reviewing the revised demand forecast submitted by the Qld DNSPs.

6.4.1 Energex

Revised regulatory proposal

MMA noted that Energex considered MMA's projection of 2007–08 and 2008–09 50% PoE maximum demand may not pick up any genuine changes in trend given the projection was based on trend analysis. MMA agreed that the summers of 2007–08 and 2008–09 have been mild and temperature sensitivity is increasing over the period, however MMA considered this impact had been incorporated into MMA's model (model B) through the temperature sensitivity coefficients.[104]

MMA noted that Energex considered the amount of weather adjustment (31 MW) applied by MMA to the actual 2008–09summer maximum demand (4593 MW) was unrealistic, as the recorded average temperature for that day (27.5 degrees celsius) was substantially below the long term average 50% PoE temperature of 30.2 degrees.[105]

MMA considered Energex's argument was statistically meaningless, since maximum demand on the hottest day (28.2 degrees) in that summer was only 4412 MW. MMA considered that the extrapolation of a single day maximum demand can be extremely misleading.[106]

MMA noted that all 50% PoE system maximum demand values are statistical estimates, produced by statistical analysis of actual maximum demand data recorded under conditions different from 50% PoE conditions. MMA did not consider demand

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102 AER, *Minutes of the Queensland public forum on Energex's and Ergon Energy's draft distribution determinations*, 8 December 2009, pp. 4–5.

103 AER, *Minutes of the Queensland public forum on Energex's and Ergon Energy's draft distribution determinations*, 8 December 2009, pp. 4–5.

104 MMA, *Review of Energex's maximum demand forecasts for the 2010–15 price review*, October 2009, table 4-1, pp. 45–46.

105 MMA, *Maximum demand forecast for the Energex region – update addendum*, March 2010, p. 8.

106 MMA, *Maximum demand forecast for Energex region – update*, March 2010, pp. 7–8.

on any single day of the year, regardless of the relevance of the conditions on that day to 50% PoE conditions, to be a good representation of 50% PoE system maximum demand in that year without conducting a statistical analysis of data including other days and conditions.[107]

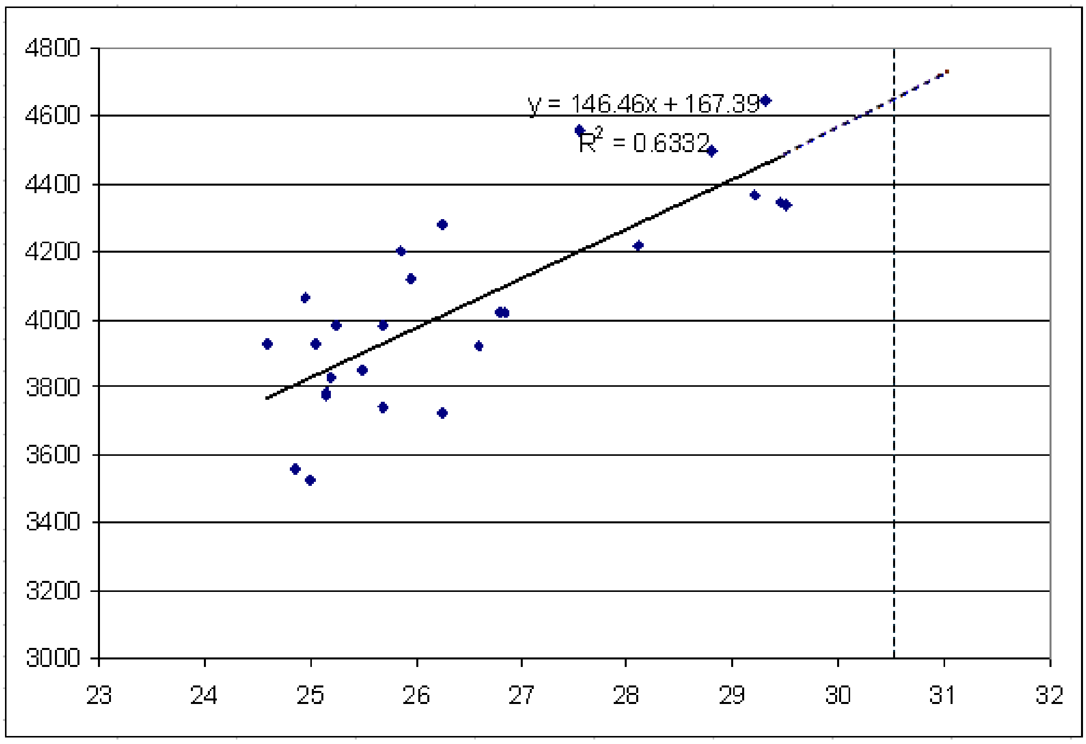
MMA further noted Energex had not found any faults with MMA's forecasting model (model B), and has not sought to refute MMA's criticism of Energex's own forecasting model (model V31). MMA therefore maintained that its system maximum demand projection developed based on model B is reasonable.[108]

Estimation of 2009–10 weather corrected 50% PoE system maximum demand

In response to a request from MMA, Energex provided MMA with daily maximum demand and temperature data for the period 1 November 2009 to 3 February 2010. MMA filtered the data to exclude maximum demands on non working days between December and February, and to exclude the period from mid December to mid January, as well as maximum demand on days with an average of maximum and minimum temperatures of less than 24 degrees.[109]

MMA estimated the 2009–10 summer 50% PoE maximum demand by fitting a linear trend to the filtered daily maximum demands and temperature data, with the result presented in figure 6.1.[110]

Figure 6.1: Linear regression analysis of Energex 2009–10 summer daily data



Source: MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 13.
Note: X-axis: average temperature (degrees) and Y-axis: daily maximum demand (MW).

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[107] MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 14.
[108] MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 10.
[109] MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 12.
[110] MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 13.

Assuming a long term 50% PoE temperature at Amberley of 30.5 degrees, MMA estimated the range for the 2009–10 summer 50% PoE maximum demand to be between 4600 and 4700MW, with a point estimate of around 4634MW.[111]

Based on its analysis of available data for the 2009–10 summer, and that of recent summers, MMA maintained that the forecast developed based on model B is reasonable.

NIEIR's updated economic outlook

MMA reviewed the economic forecasts contained in NIEIR's reports, and found the forecast GSP growth rates over the period 2009 to 2015 were largely the same in both the April 2009 and October 2009 reports, despite changes in the timing of the growth. Overall, MMA considered NIEIR's economic growth forecasts to be the most timely, currently available forecast.[112]

In its 2009 report to the AER, MMA noted that:[113]

> the Australian and Queensland economies remain volatile. We have used economic forecasts for Queensland prepared in April 2009 as the basis of our analysis of system maximum demand. If there is a material change to the expected outlook then it may also materially impact on the forecasts.

Based on its review of NIEIR's updated economic forecasts, MMA considered it is reasonable to use NIEIR's economic forecasts to update its alternative demand forecast model.[114] MMA also reconsidered and revised its own assumption in relation to the estimated growth of additional air conditioners based on the Queensland Office of Economic and Statistical Research May 2008 household survey, and has incorporated this effect into its updated forecast.[115]

Conclusion and updated system maximum demand forecast

Based on its review of Energex's revised proposal and other submissions, MMA maintained its conclusion from its 2009 report that Energex's maximum demand forecasts were not reasonable. MMA updated its own maximum demand forecasts to reflect NIEIR's updated economic forecast, and the revised projection of air conditioner growth. MMA's original and updated forecasts are presented in table 6.6.[116]

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111 MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 13. 50% PoE system maximum demand estimate derived based on the linear extension of the regression line to the assumed 50% PoE temperature.

112 MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 10.

113 MMA, *Review of Energex's maximum demand forecasts for the 2010–15 price review*, October 2009, p. 7.

114 MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 11.

115 MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 16.

116 MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 16.

Table 6.6: Original and updated MMA forecasts of Energex system 50% PoE maximum demand including demand management initiatives (MW)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
MMA March 2010 forecast	4784	4931	5089	5328	5555	5733
MMA October 2009 forecast	4762	4864	5027	5228	5467	5684
Energex revised proposal forecast	5009	5118	5376	5655	5814	5940

Source: MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 17; and Energex, *Revised regulatory proposal*, January 2010, Appendix 2.1, NIEIR Demand forecasts October 2009, table 7.3, confidential.

MMA noted its updated forecast was approximately 200MW or 3.5 per cent below Energex's revised forecast in the first and the last years of the regulatory control period, with the major point of difference being the starting point rather than the growth rate.[117]

6.4.2 Ergon Energy

Ergon Energy revised forecast

MMA noted that Ergon Energy had provided new forecasts and information and stated its revised capex forecasts prepared based on its March 2007 (2007 forecast) bottom up demand forecast were realistic.[118]

MMA reviewed Ergon Energy's revised maximum demand forecasts at both the coincident system and regional sum levels.[119] MMA considered the sum of six regional maximum demands represented a better measure of forecast system capex requirements as it does not require assumptions to be made about regional diversity factors.[120]

MMA noted that although Ergon Energy's revised 2009 coincident system maximum demand forecast prepared in December 2009 (2009 forecast) closely aligned with its 2007 forecast, the sum of the six regional coincident maximum demand forecasts were different between the 2007 and 2009 forecasts, and clearly different to that produced by NIEIR.[121]

As shown in figure 6.2, over the next regulatory control period Ergon Energy's 2009 forecast of average regional sum maximum demand is around 5.6 per cent less than it

117 MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 17.

118 MMA, *Maximum demand forecast for the Ergon Energy region – update addendum*, March 2010, p. vi.

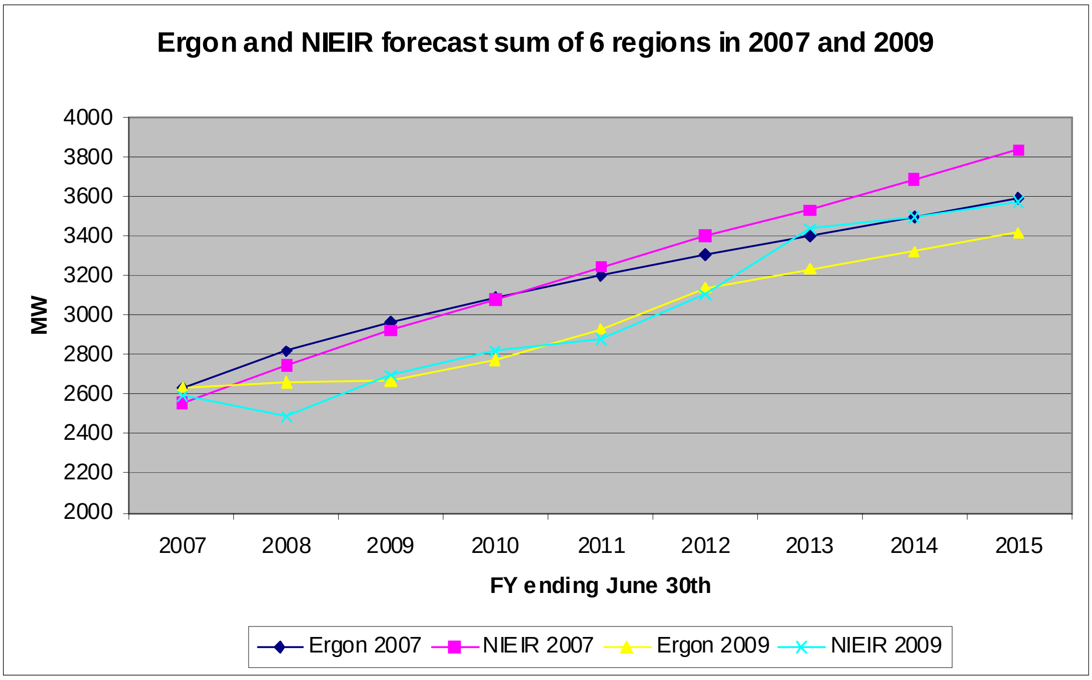
119 There are six regions within Ergon Energy's network: Far North, North Queensland, Mackay, Capricornia, Wide Bay and South West. See Ergon Energy, *Regulatory proposal*, July 2009, p. 165.

120 Regional maximum is the coincident maximum demand at the time of the individual region network peak demands. Ergon Energy, response to AER request AER.ERG.RRP.08, February 2010.

121 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 6–9.

forecast in September 2007. Similarly, between the 2007 and 2009 reports, NIEIR's sum regional maximum demand forecasts over the next regulatory control period also reduced by, on average, around seven per cent. MMA further noted that NIEIR's 2009 forecast is on average around three per cent below the Ergon Energy 2007 forecasts across the next regulatory control period.[122]

Figure 6.2: Ergon Energy and NIEIR regional sum maximum demand forecasts, (MW)



Source: MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. iv.

Based on its analysis, MMA considered both Ergon Energy's 2009 forecast and the NIEIR 2009 forecast are substantially below the analogous forecasts in 2007, primarily due to the effects of the GFC which were not considered in the 2007 forecasts.[123]

NIEIR system maximum demand forecast

MMA noted that Ergon Energy had relied on the latest NIEIR forecasts prepared in December 2009 to either validate or to replace its bottom up forecasts. However, the internal mechanics of the NIEIR model including the actual parameters and assumptions used by NIEIR in generating the forecasts for Ergon Energy were considered commercially confidential, and not open to scrutiny by MMA or the AER.[124]

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[122] MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 7–8.
[123] MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. vi.
[124] MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 10.

Nonetheless, MMA considered that developing maximum demand forecasts for Ergon Energy required large number of assumptions and estimates to be made, for example:[125]

- assumptions about coincidence factors across supply points and regions
- air conditioner uptake assumptions
- assessment of new large loads (spot loads) and the probability of these proceeding, and deciding whether they should be included within the general econometric model or added separately
- assumptions about whether spot loads will be supplied from transmission or distribution lines.

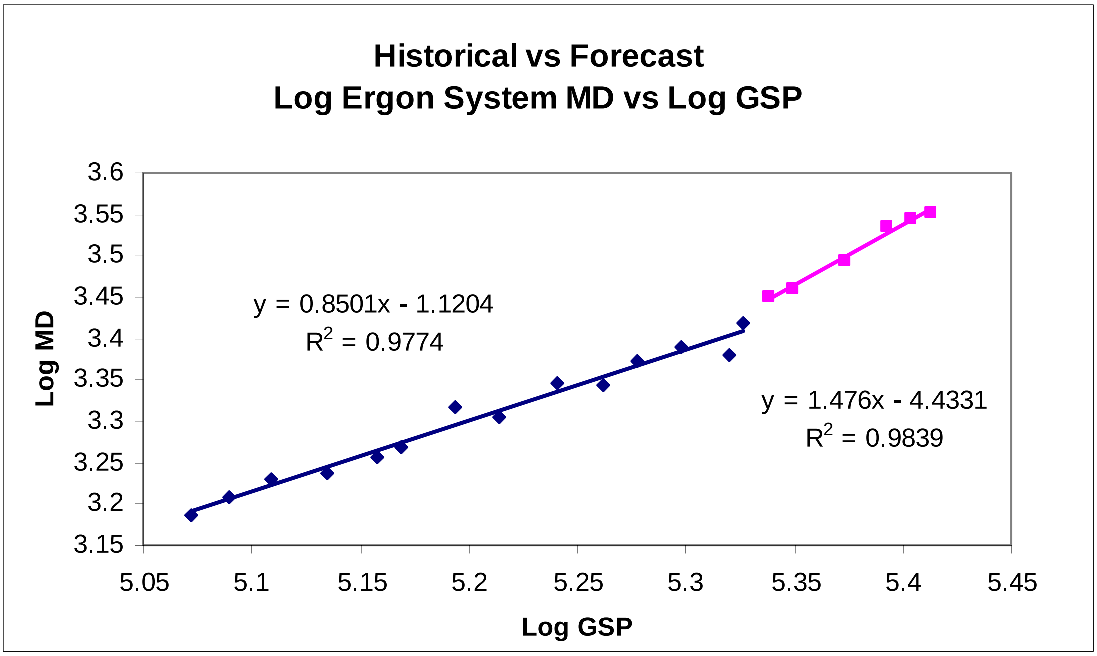
While MMA did not review NIEIR's forecasting methodology and models, it was able to make the following observations about the NIEIR forecasts based on a high level examination of the outputs.[126]

MMA noted that one of the key inputs into the NIEIR model is the growth in economic activity represented by either Queensland GSP or Gross Regional Product (GRP). After reviewing the historic and forecast GSP growth contained in the NIEIR report, MMA noted that NIEIR's forecast GSP growth over the period 2009 to 2015 reduced from 3.7 per cent per year in the 2007 report to 3.1 per cent in its 2009 report. This is lower than the actual GSP growth observed between 2002 and 2007 of about 5 per cent per year. Overall, MMA considered the latest NIEIR economic growth forecasts to be most timely currently available, and that it was reasonable to use these economic forecasts as inputs to the maximum demand model.[127]

Using historical data from the Australian Bureau of Statistics (ABS) and 50% PoE system maximum demand data sourced from supporting documents provided by Ergon Energy for the period 1996 to 2009, MMA plotted a log-log graph to estimate the elasticity relationship between GSP and system maximum demand growth.[128] This is shown in figure 6.3.

125 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 10.
126 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 10.
127 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 20–21.
128 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 10–11. Data sourced from: Ergon Energy, *Revised regulatory proposal*, January 2010, AR412c_EE_Demand Load Forecasts 2008.xls (confidential), RP981c Evans & Peck Demand Review figure 1.4 (confidential), RP970c NIEIR 2009 Demand Forecast, table 7.1 (confidential). A small movement in the natural log scale is approximately equivalent to a percentage movement in level terms.

Figure 6.3: Log system maximum demand against Log GSP



Source: MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 11.

MMA noted that using only GSP as the explanatory variable, the NIEIR forecasts appeared to show a higher elasticity between system maximum demand and GSP going forward than has been seen over recent years, with forecast elasticity of 1.48 versus 0.85 historically.[129]

MMA questioned Ergon Energy regarding the relationship between GSP or GRP and system maximum demand forecast by NIEIR. Ergon Energy's response suggested that it is simplistic to consider economic growth in isolation and that many other factors such as regional versus state growth, growth in air conditioning penetration and population, and large new projects and lag effects should also be considered. MMA subsequently reviewed the forecasts of other potential demand drivers such as GRP, population and dwelling growth and air conditioner growth. It found that over the period 2010 to 2015 the forecast growth rates for these drivers are likely to be either the same as, or lower than, actuals over the 2004–2009 period.[130]

MMA reviewed NIEIR's treatment of spot loads as it considered the inclusion of large spot loads may explain the differences between the historical and NIEIR's forecast elasticity of system maximum demand to GSP. After reviewing supporting documents and responses provided by NIEIR, MMA considered there was insufficient information for it to make a proper assessment of NIEIR's spot load forecasts. Nonetheless, MMA identified some evidence of potential differences in assumptions made by Ergon Energy and NIEIR in relation to spot loads, such as the allocation of spots loads between transmission and distribution network.[131]

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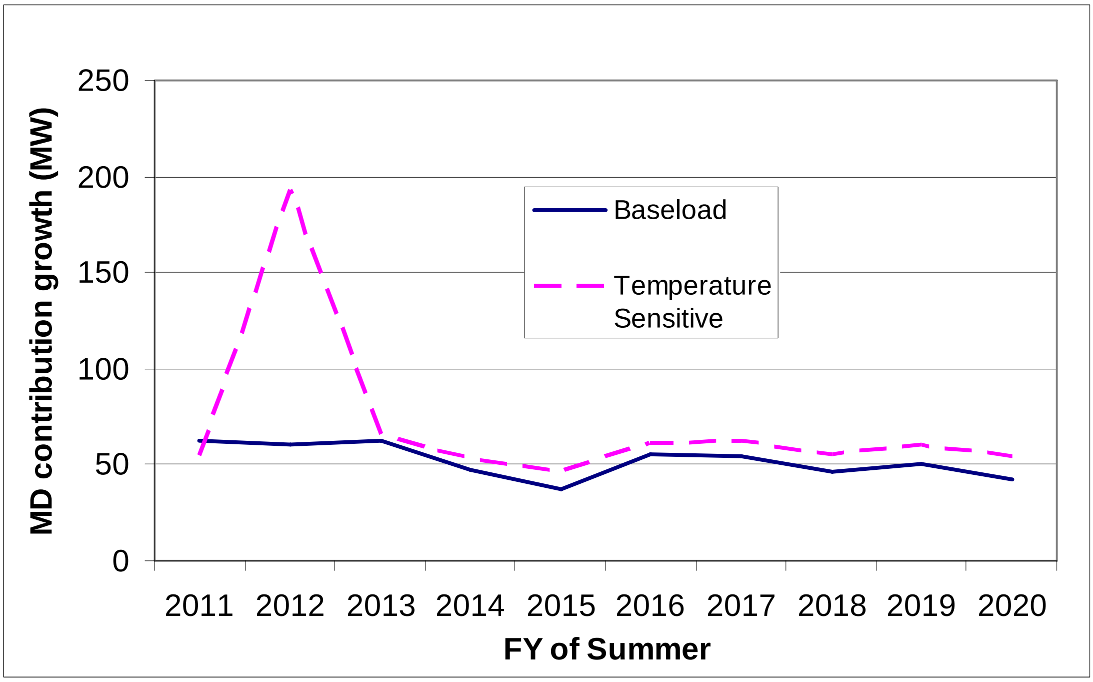
[129] MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 12.
[130] MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 12.
[131] MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 15–16.

MMA noted that NIEIR forecast temperature sensitive load and base (temperature insensitive) load separately. As shown in figure 6.4, NIEIR has projected a large step increase in system maximum demand in 2011–2012. This increase is more than double the average increase over the next regulatory control period, and is largely driven by an increase in temperature sensitive load. Figure 6.4 illustrates the temperature sensitive and base load components of the overall increases in NIEIR's forecast system maximum demand.[132]

Figure 6.4: NIEIR 2009 system maximum demand forecast



Source: MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 13.

In response to MMA's question in relation to the large maximum demand increase in 2012, Ergon Energy indicated that the demand growth in the early part of NIEIR's forecast is driven by strong demand in the resource sector.[133]

In the absence of a sectoral break down of the maximum demand forecast, MMA reviewed NIEIR's sectoral energy consumption forecast. MMA noted that the sector with the highest growth rate in energy consumption for 2012 is the commercial sector with 5.6 per cent growth compared to total energy growth of 3.4 per cent. MMA further noted that the commercial sector accounts for 21 per cent of total energy sales in 2010, which is substantially smaller than both the industrial (41 per cent) and residential (28.5 per cent) sectors. While the large increase in temperature sensitive load in 2012 might possibly be due to the strong increase in commercial energy sales, a slightly lower increase (4.8 per cent) in commercial energy sales in 2013 is not accompanied by a similar increase in temperature sensitive maximum demand in that

[132] MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 12–13.
[133] MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 13–14.

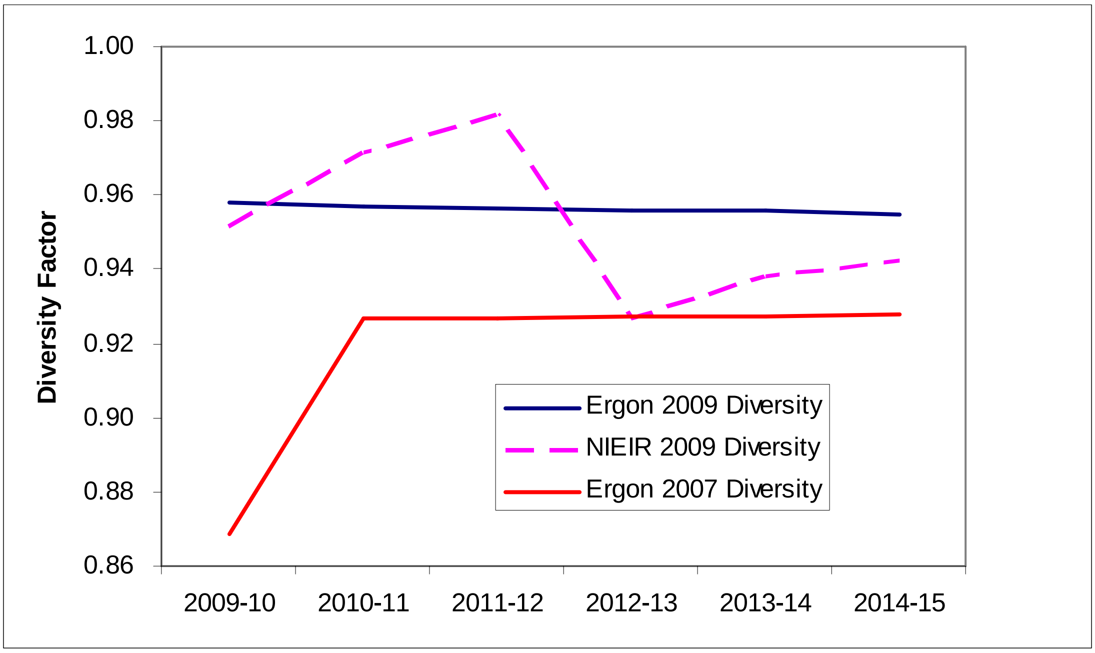
year. MMA also failed to identify evidence of particularly strong energy sales growth in any specific region or for a specific project.[134]

Based on the above analysis, MMA considered that it had not seen sufficient evidence to explain why such a large increase in temperature sensitive maximum demand is forecast to occur in 2012, when the total energy sales increase is greater in 2013. MMA therefore concluded that the large increase in temperature sensitive load in 2012 appears anomalous.[135]

MMA compared Ergon Energy's and NIEIR's assumed (or derived) regional diversity, as it is used to connect the coincident system maximum demand forecast to the sum of regional forecasts.[136]

Figure 6.5 shows the diversity factors assumed (or derived) by the two organisations were quite different. MMA considered this would have ramifications for the system maximum demand forecasts and raised questions about the consistency of diversity factors used at lower levels of the network.[137]

Figure 6.5: System diversity factor in Ergon Energy and NIEIR forecasts



Source: MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 17.

Revised regulatory proposal

Ergon Energy submitted new material in relation to its treatment of spot loads, including a report produced by Evans & Peck. MMA noted that Evans & Peck made

134 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 14.
135 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 14.
136 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 16.
137 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 16–17.

the following comments in relation to MMA's conclusion on Ergon Energy's spot load forecasts:[138]

> MMA has identified the potential for double counting of spot loads in forecasts – our analysis does not separate spot loads and therefore implicitly incorporates a "business as usual" level of spot load. We have no material difference to Ergon Energy or NIEIR in our forecast to 2010/11 and are therefore satisfied that there is no double counting to that point.

MMA did not consider that Evans & Peck's analysis disproved MMA's findings as to the double counting of spot loads, as the 2009–10 and 2010–11 diversified system maximum demand forecasts provided by Evans & Peck were lower than Ergon Energy's 2007 forecast, on which the capex forecast was based.[139]

MMA reviewed Ergon Energy's arguments in relation to MMA's alternative forecasts accepted by the AER in the draft decision, including that:[140]

- MMA's top down forecast is based on out of date historic and forecast GSP data
- MMA's forecasting model did not include variables that differentiate the south east Queensland dominated state product from regional Queensland product
- it is inappropriate to rely on Queensland GSP as a proxy for growth in regional Queensland given its higher exposure to the rapidly recovering Asian export markets.

In respect to the first point raised by Ergon Energy, MMA noted that in its previous report to the AER, it stated that:[141]

> …we note that the Australian and Queensland economies remain volatile. We have used economic forecasts for Queensland prepared in April 2009 as the basis of our analysis of system maximum demand. If there is a material change to the expected outlook then it may also materially impact on the forecasts.

In light of more recent data and based on its consideration of NIEIR's updated forecast, MMA accepted that it is reasonable to use NIEIR's economic forecasts to update its maximum demand projections.[142]

MMA's analysis found that despite Ergon Energy's assertions about regional Queensland's GRP growth being unrelated to the Queensland GSP growth, recent history showed that regional GRP growth closely tracked Queensland GSP growth while being on average a little lower as illustrated in figure 6.6.[143]

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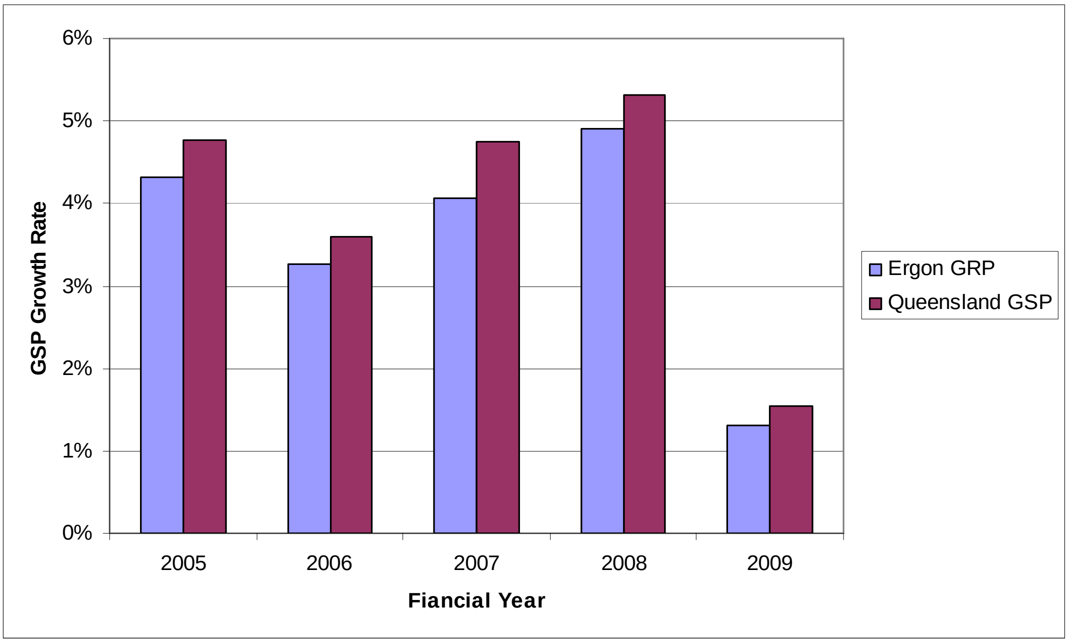
138 Ergon Energy, *Revised regulatory proposal – RP981c Evans & Peck Demand Review*, p. 5.
139 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 19.
140 Ergon Energy, *Revised regulatory proposal,* January 2010 p. 79.
141 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 20–21.
142 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 21.
143 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 21.

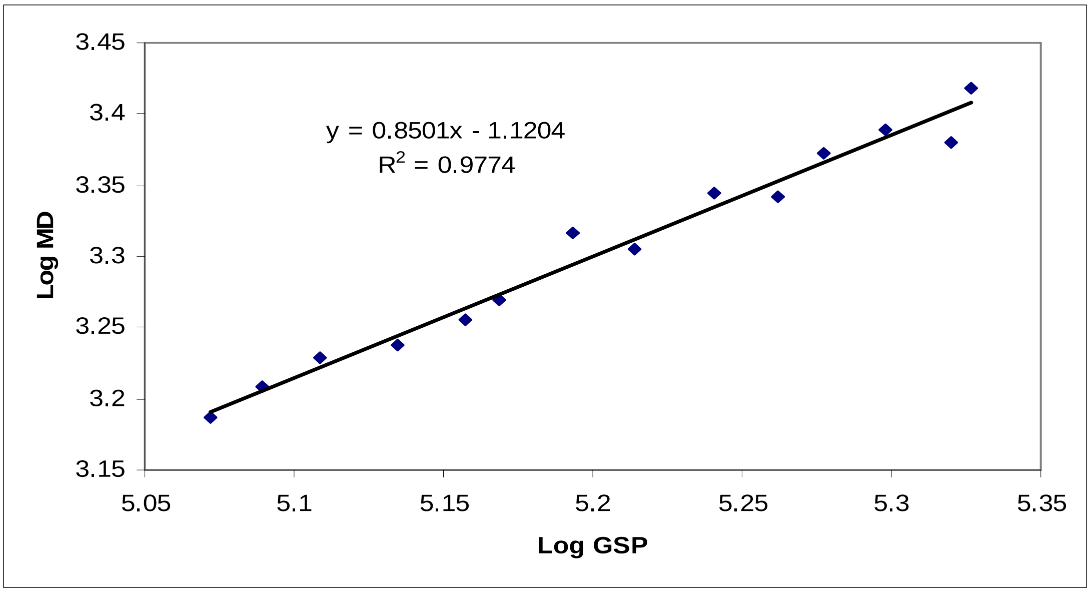
Figure 6.6: Comparison between Queensland regional GRP and GSP growth



Source: MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 21.

MMA plotted Ergon Energy' historical weather corrected system maximum demand against Queensland GSP in natural log forms, and found Ergon Energy's system maximum demand closely correlated with Queensland GSP as indicated by the high R squared value of 0.98, as shown in figure 6.7.[144]

Figure 6.7: Log system maximum demand against Log GSP

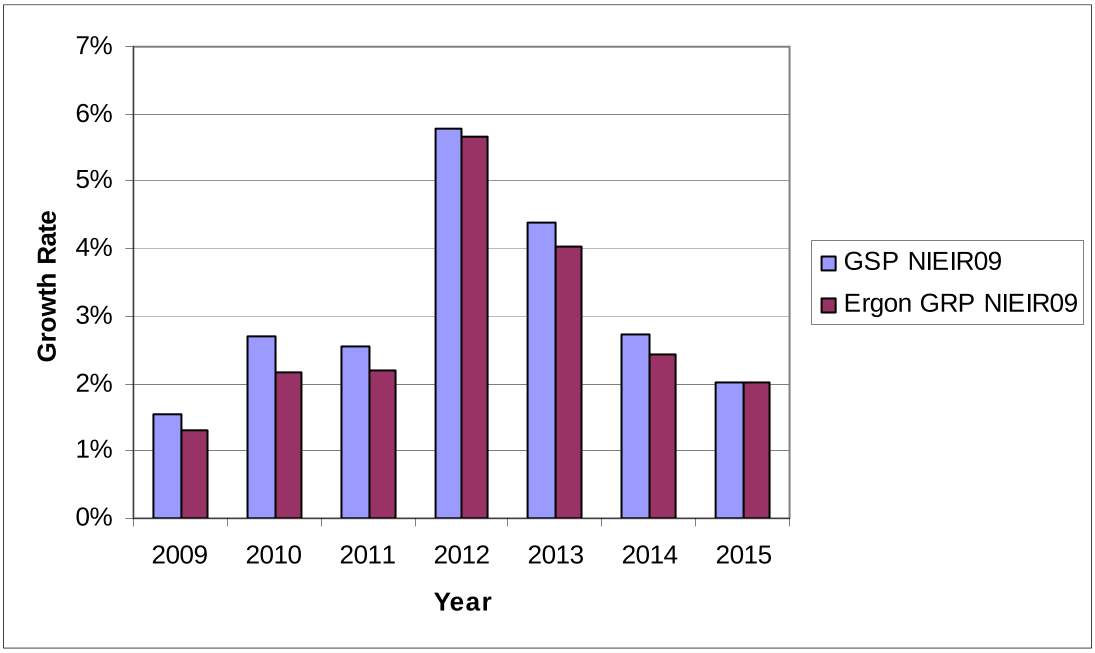


Source: MMA, *Maximum demand forecast for Ergon Energy's region – update*, March 2010, p. 22.

[144] The system maximum demand historical data came from Ergon Energy for 1996 to 2004 and from Evans & Peck's weather and diversity corrected data for 2005 to 2009. See MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 22.

MMA noted that while Ergon Energy argued that it expects the resources sector of Queensland to experience a boom compared to the rest of Queensland over the next regulatory control period, NIEIR's forecast shown that the GRP growth for the Ergon Energy region as a whole was a little lower than that for the state, as illustrated in figure 6.8.[145]

Figure 6.8: NIEIR forecasts for Queensland GSP and Ergon Energy region GRP from the December 2009 forecasts.



Source: MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 23.

MMA reviewed Evans & Peck's independent analysis of Ergon Energy's weather sensitive load and air conditioner penetration. MMA considered that although its analysis of air conditioner penetration rates provided to the AER in its 2009 report remained sound, MMA accepted that there may be some further growth to air conditioner penetration driven by an increase in installations of secondary units. MMA has incorporated the impact of this growth into its updated forecast presented in table 6.6.[146]

Conclusion and MMA's updated system maximum demand forecast

MMA has previously assessed Ergon Energy's 2007 demand forecasts, on which the revised capex forecasts have been based. MMA reviewed the arguments and new material submitted by Ergon Energy with its revised regulatory proposal. This included new forecasts developed by Ergon Energy in 2009, which at the coincident system maximum demand level were largely the same as its 2007 forecasts.[147]

Although MMA was unable to provide a detailed review of NIEIR's demand forecasts due to the confidential nature of the NIEIR model, it has observed some potential

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145 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 22–23.
146 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 24
147 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. i.

issues with the use of these forecasts, including an apparent difference between the historic and forecast elasticity of maximum demand to economic growth, unexplained substantial increases in temperature sensitive load in 2012, uncertainty about the inclusion of large spot loads, including criteria for inclusion, timing and whether these loads are connected to the distribution network or transmission system, and inconsistent regional diversity factors between the NIEIR and Ergon Energy 2009 forecasts.[148]

MMA did not consider the new material and forecasts provided by Ergon Energy have substantiated the use of Ergon 2007 capex forecasts. MMA concluded that even without further review or amendment the Ergon Energy 2009 and NIEIR 2009 regional sum maximum demand forecasts suggest reductions of some 3 per cent and 5.6 per cent respectively from the Ergon Energy 2007 forecast levels.[149]

Overall, MMA concluded that the new information provided did not cause MMA to alter its previous conclusions regarding the reasonableness of the Ergon Energy's 2007 demand forecasts. On this basis MMA updated its indicative system maximum demand forecast taking account of updated economic forecasts and revised air conditioner growth assumptions. After updating, MMA's indicative forecasts of Ergon Energy system maximum demand were some 5 per cent per annum below the Ergon Energy 2007 forecasts.[150]

MMA's indicative system maximum demand forecast for Ergon Energy is presented in table 6.7.

Table 6.7: Ergon Energy revised proposal 50% PoE system maximum demand forecast, and MMA updated indicative 50% PoE system maximum demand (MW)

	2010	2011	2012	2013	2014	2015
NIEIR December 2009	2681	2799	3052	3181	3282	3365
Ergon Energy revised forecast	2654	2807	3052	3181	3282	3365
MMA indicative 2009 forecast	2607	2693	2811	2928	3031	3121
MMA indicative 2010 forecast	2704	2778	2907	3017	3100	3171

Source: MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 27.

6.5 Issues and AER considerations

6.5.1 Energex

The AER notes that Energex's revised maximum demand forecast are largely the same as its original forecasts, with both sets of forecasts having been adjusted by the same amount to reflect Energex's proposed demand management initiatives accepted in the draft decision.

148 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. v.
149 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. v.
150 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. v–vi.

The AER notes that one of the main differences between Energex's revised maximum demand forecast and MMA's alternative forecast accepted by the AER in the draft decision is the starting point (2008–09 50% PoE maximum demand). This is shown in table 6.8.

Table 6.8: Comparison of Energex and MMA's system 50% PoE maximum demand forecast including the impacts of demand management initiatives

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
MMA October 2009 forecast	4624	4762	4864	5027	5228	5467	5684
Energex revised forecast	4899	5009	5118	5376	5655	5814	5940
Difference	–275	–247	–254	–349	–427	–347	–256

Source: Energex, *Revised regulatory proposal*, January 2010, pp. 9–11; and MMA, *Maximum demand forecast for Energex region – update*, March 2010, pp. 18–19.

The AER notes Energex has concerns in relation to MMA's estimated 2008–09 50% PoE system maximum demand. The AER notes that Energex has not identified any error with MMA's forecasting model (Model B), other than criticising the model for ignoring changes in temperature sensitive load. However this impact has been accounted for in the model through the inclusion of growing temperature sensitivity coefficients.[151]

The AER notes that Energex's revised estimate of the 2008–09 maximum demand was based on the same ACIL Tasman model (model V31) it used in its original regulatory proposal.[152]

Based on MMA's assessment, the AER concluded in its draft decision:[153]

> … the model used by Energex to produce its baseline system maximum demand forecasts appears to double count maximum demand growth due to GSP growth and air conditioner penetration, and that the absolute number of air conditioners should be used in the model to provide a better measure of air conditioner growth.
>
> For these reasons the AER considers that Energex's baseline system maximum demand forecasts and the model used to produce them do not provide a reasonable expectation of demand.

The AER notes that Energex did not raise issues in relation to MMA's assessment of the biases and the unsuitability of the ACIL Tasman model. On this basis, the AER confirms its view that MMA's estimated 50% PoE maximum demand based on model B, which removed the bias associated the ACIL Tasman model, provides a more realistic estimate for the 50% PoE 2008–09 system maximum demand.

The AER notes Energex has adopted NIEIR's forecast in its revised proposal. As part of the review process, the AER and MMA requested details about NIEIR's

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151 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 7.
152 Energex, *Revised regulatory proposal*, January 2010, p. 8.
153 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 70–71.

forecasting methodology and models. While general information was provided, the actual parameters and assumptions used by NIEIR in generating the forecasts were considered commercially confidential and therefore not available for review by the AER or MMA.[154] This effectively limited MMA and the AER's review to the input assumptions used in the model and actual model outputs.

Based on MMA's review, the AER accepts that NIEIR's Queensland GSP forecasts are reasonable and agrees that it is appropriate to update MMA's alternative maximum demand forecast based on NIEIR's GSP forecast for the purposes of comparing the forecasts produced by MMA and NIEIR. The AER also reviewed MMA's revised air conditioner projections and considered it to be reasonable for MMA to incorporate this effect into its updated maximum demand forecasts.

The AER notes the data provided by Energex indicated 2009–10 summer system maximum demand of 4647MW occurred on Monday 18 January 2010, with maximum and minimum temperatures of 38 and 21 degrees.[155] The average temperature of 29.3 degrees is slightly below the long term average 50% PoE temperature of approximately 30 degrees.[156] The AER further notes that NIEIR's projection of 50% PoE maximum demand is around 362 MW higher than the actual. The AER does however agree with MMA's view that the annual weather adjusted 50% PoE maximum demand should be estimated based on statistical analysis of daily summer maximum demand and corresponding temperatures, rather than the extrapolation of a single annual peak temperature day maximum demand.[157]

The AER reviewed NIEIR's October 2009 maximum demand forecasts and found NIEIR's estimate of 2009–10 50% PoE summer maximum demand lies around 350MW above MMA's estimate derived based on actual data, and around 220MW higher than the estimate produced by model B.[158]

On the basis of its conclusion as to the reasonableness of MMA's model B, the AER considers MMA's indicative 50% PoE 2009–10 maximum demand produced by model B (4784MW) represents a more realistic expectation of demand compared to NIEIR's estimate of 5009MW.

For the reasons discussed, and as a result of the AER's consideration of Energex's regulatory proposal, MMA's report and other material, the AER is not satisfied that Energex's revised maximum demand forecast provides a realistic expectation of the demand forecast required to achieve the capex and opex objectives. The AER considers that reducing Energex's forecast maximum demand to the levels shown in table 6.9 provides a more realistic basis for determining capex and opex forecasts that would comply with the NER.

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154 Energex, response to AER request AER.EGX.RP.1.7, 12 February 2010, confidential.

155 Based on partial summer data over the period 1 November 2009 to 3 February 2010.

156 Based on Energex's and MMA's estimate, see Energex, *Revised regulatory proposal*, January 13, p. 8; and MMA, *Maximum demand forecast for Energex's region – update*, March 2010, p. 12.

157 MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 9.

158 MMA, *Maximum demand forecast for Energex region – update*, March 2010, pp. 13–16.

Table 6.9: MMA updated forecasts of Energex system 50% PoE maximum demand including impacts of demand management initiatives (MW)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
MMA March 2010 forecast	4624	4784	4931	5089	5328	5555	5733
Energex revised forecast	4899	5009	5118	5376	5655	5814	5940
Difference	–275	–225	–187	–287	–327	–260	–208

Source: MMA, *Maximum demand forecast for Energex region – update*, March 2010, p. 15.

6.5.2 Ergon Energy

Ergon Energy 2009 bottom up forecast

The AER notes that both MMA and Ergon Energy's consultant Evans & Peck considered the demand forecast based on the sum of regional maximum demands provides a better measure of forecast system capex requirements for Ergon Energy's network based on the following arguments:

- sum of regional maximum demands does not require assumptions to be made about regional diversity factors[159]
- system maximum demand is not necessarily the primary driver of capex in a system as diversified as that of Ergon Energy with limited interconnection between regions.[160]

The AER notes that Ergon Energy's 2009 regional sum maximum demand forecasts are on average 5.6 per cent lower than its 2007 forecast over the next regulatory control period. The AER further notes that despite reductions in regional sum maximum demand forecasts between 2007 and 2009, there is little difference between the two forecasts at coincident system maximum demand level apart from the first year of the next regulatory control period, largely due to an increase in assumed (or derived) system diversity factors from 0.92 to 0.96.[161]

Irrespective of the reasonableness of Ergon Energy's assumed diversity factors and the resultant system maximum demand forecasts, the AER notes that Ergon Energy's 2009 demand forecast is substantially lower than its 2007 forecast, given the 2009 regional sum maximum demand forecasts are on average 5.6 per cent lower than the 2007 forecast. Consequently, the AER does not consider it is prudent to use the 2007 bottom up maximum demand forecast as the basis for the revised capex forecast as proposed by Ergon Energy in its revised regulatory proposal.

159 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. i.

160 Ergon Energy, *Revised regulatory proposal*, Attachment RP981c *Evans & Peck Independent review of aspects of load forecast*, pp. 13–14, (confidential).

161 Diversity factor is calculated based on the ratio of the maximum demand of the entire Ergon Energy network and the sum of the six individual regional maximum demands (at the time of the regional peak). Under this definition, the diversity factor is usually less than 1. An increase in diversity factor indicates a convergence of system and sum regional maximum demands.

The AER notes that Ergon Energy's consultant Evans & Peck provided two years (2009–10 to 2010–11) of weather adjusted system maximum demand projections to validate Ergon Energy's and NIEIR's 2009 system maximum demand forecasts over the same period. Evans & Peck concluded in its report that the comparison of its system maximum demand projection based on a linear trend analysis confirmed there is no double counting of spot loads in Ergon Energy's spatial demand forecast.[162]

Irrespective of the reasonableness of Evans & Peck's projections, the AER considers the comparison between Evans & Peck's projected system maximum demand and Ergon Energy's 2009 system maximum demand forecast is irrelevant to the AER's assessment of the reasonableness of Ergon Energy's demand forecast, as Ergon Energy has based its revised capex forecast on its regional maximum demand forecasts prepared in 2007, which are substantially higher than its 2009 forecasts.

The AER considers any comparative analysis relevant to its assessment of the demand expectations underpinning Ergon Energy's revised capex forecast should be based on Ergon Energy's 2007 system maximum demand forecast.

The AER compared Evans & Peck's forecast against Ergon Energy's 2007 forecasts, and notes that Evans & Peck's forecasts (2009–10 and 2010–11) are on average around 6 per cent lower than Ergon Energy's forecasts prepared in 2007, in terms of both system maximum demand and regional sum maximum demand.[163]

Based on MMA's review of additional material provided by Ergon Energy in relation the spatial demand forecast methodology, the AER maintains its draft determination conclusion that Ergon Energy's spatial demand forecast tends to overestimate the size and timing of spot loads.[164]

Based on MMA's assessment, and the AER's review of Ergon Energy's revised regulatory proposal, the AER considers that the maximum demand forecasts contained within Ergon Energy' revised regulatory proposal do not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the NER.

Consideration of NIEIR's top down forecasts

The AER notes that Ergon Energy proposed that in the event the AER does not accept Ergon Energy's revised demand forecast, the AER should then consider NIEIR's top down demand forecast.

The AER maintains its draft determination decision that it is reasonable to use a top down approach to address Ergon Energy's methodological deficiencies at the spatial level. In this context, the AER has considered the reasonableness of NIEIR's and MMA's top down system maximum demand forecasts.

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162 Ergon Energy, *Revised regulatory proposal*, Attachment RP981c *Evans & Peck Independent review of aspects of load forecast*, p. 21, (confidential).

163 Calculation based on data sourced from Ergon Energy, *Regulatory proposal*, July 2009, attachment AR436c (confidential), Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP981c, p. 15–16 (confidential). Regional sum maximum demand was derived by the AER using Evans & Peck's linear trend analysis.

164 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 17–19.

As noted in section 6.4.2 the internal mechanics of the NIEIR model including the actual parameters and assumptions used by NIEIR in generating its forecasts for Ergon Energy are considered commercially confidential. This lack of transparency effectively limited MMA and the AER to a review of the input assumptions used in the model and actual model outputs.[165]

Based on MMA's advice, the AER considers NIEIR's GSP and dwelling growth forecasts over the next regulatory control period to be reasonable input assumptions for these variables.[166]

The AER found that despite the close alignment between Ergon Energy and NIEIR's forecasts at system maximum demand level, there are substantial differences between the two forecasts when regional sum maximum demands were compared (see figure 6.2).

The AER notes that the two forecasts show close alignment at the system level mainly due to the differences in assumed system diversity factors used by Ergon Energy and NIEIR, with NIEIR's assumed diversity factors also showing large fluctuations over the next regulatory control period. A closer examination of the forecasts found the inconsistencies between them exist across all regions, in particular in the North Queensland, South West Queensland, and Wide Bay regions.[167]

As illustrated in figure 6.3, NIEIR's system maximum demand forecast shows a higher elasticity between system maximum demand and GSP compared to that observed over the last 13 years. The AER notes the increase appears to be inconsistent with growth rate forecasts of other potential key drivers of demand over the next regulatory control period, such as sum regional GRP, population, and dwelling stock growth forecasts, shown in table 6.10, which are either the same or lower with respect to the most recent observations.[168]

Table 6.10: Comparison of recent and forecast growth rates for sum regional GRP, population, and dwelling stock

	Average growth rate 2005–2009	Average forecast growth rate 2010–15
Sum regional GRP	3.4%	3.1%
Population	2.1%	1.8%
Dwelling stock	2.1%	1.7%

Source: Ergon Energy, *Revised regulatory proposal*, attachment RP 970c NIEIR 2009 demand forecast, table 4.-4.3 (confidential).

165 Ergon Energy, response to AER's request AER.ERG.RRP.11, February 2010.

166 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 20.

167 Calculated based on Ergon Energy, *Revised regaultory proposal*, attachment RP929c_EE_Region BSP & CP 2009 Forecast_23Dec09 (confidential), and attachment RP 970c *NIEIR 2009 demand forecast*, table 9.1–9.6 (confidential).

168 Historic and forecast growth rates calculated based on Ergon Energy, *Revised regulatory proposal*, attachment RP 970c NIEIR 2009 demand forecast, Table 4-4.3.

The AER notes that NIEIR has forecast a large step increase in temperature sensitive load in 2011–12 (see figure 6.4).[169] The AER considers this step increase appears to be inconsistent with the forecast growth of potential key drivers of temperature sensitive demand, with no step change in forecast population and dwelling stock growth.[170] The AER also reviewed publicly available projections of air conditioner stocks in Queensland in 2011–12 and found no indication of a step change in expected growth of air conditioners.[171] MMA's analysis also found this increase in temperature sensitive load appeared to be inconsistent with NIEIR's energy sales forecasts.[172]

On the basis of its review, and in the context of the lack of detailed information about the operation of the NIEIR model available to MMA and the AER, the AER is not satisfied that the NIEIR system maximum demand forecast has been demonstrated to reflect a realistic expectation of demand.

Ergon Energy comments and Powerlink submission

Ergon Energy questioned the use of GSP as the sole economic variable in forecasting system maximum demand over its network. Ergon Energy stated that the regional Queensland economy was significantly weighted towards resources and the rural sector, and has a high level of exposure to the export market, and that the growth in these sectors depends on the growth of Australia's trading partners in Asia rather than the rest of Queensland.[173]

Powerlink also questioned the usefulness of GSP in forecasting maximum demand in its submission to the AER, stating that the monetary measure of GSP may not match the underlying levels of physical activity in the current economic environment.[174]

The AER considers MMA's analysis based on historic data and NIEIR's forecasts of regional Queensland GRP and Queensland GSP demonstrated the close relationship between regional GRP and Queensland GSP, as shown in figure 6.6, figure 6.8 and figure 6.9. Based on recent data, sum regional Queensland GRP closely tracks Queensland GSP, while NIEIR's forecast over the next regulatory control period shows a slower growth in regional GRP, resulting in a marginal decline in the sum regional GRP as a proportion of the GSP.[175]

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169 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 13.

170 Calculated based on Ergon Energy, *Revised regulatory proposal*, attachment RP 970c NIEIR 2009 demand forecast, table 4.1–4.3.

171 Queensland Office of Statistical and Economic Research, 2008 Survey.
Department of the Environment, Water, Heritage and the Arts, *Regulatory Impact Statement: Revision to the Energy Labelling Algorithms and Revised MEPS levels and Other Requirements for Air Conditioners*, p. 159.

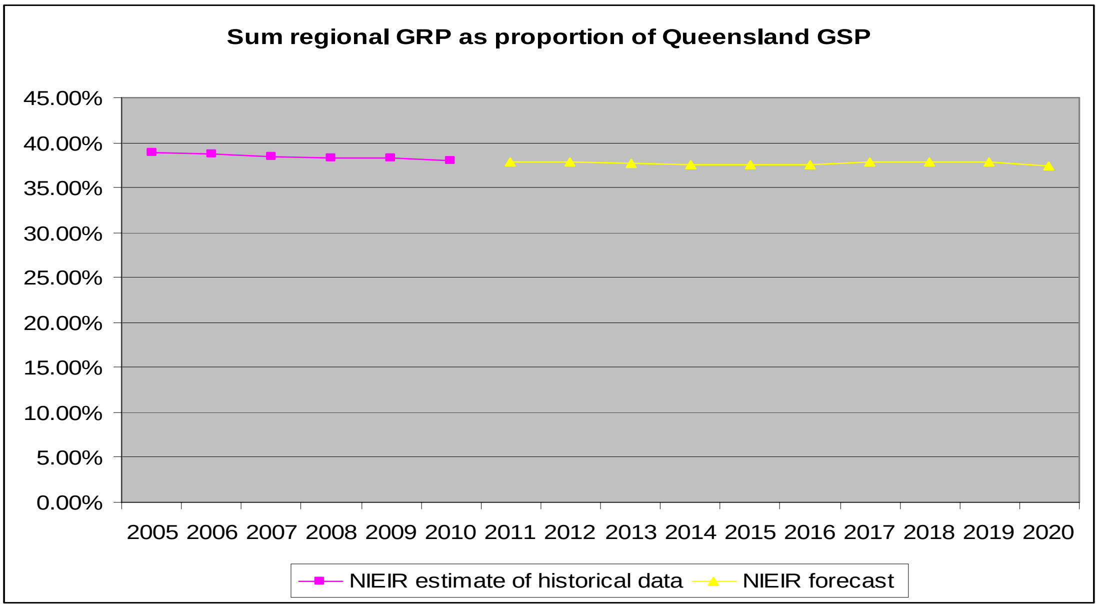
172 MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, pp. 13–14.

173 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 71.

174 AER, *Minutes of the Queensland public forum on Energex's and Ergon Energy's draft distribution determinations*, 8 December 2009.

175 Calculated based on Ergon Energy, *Revised regulatory proposal*, Attachment RP970c NIEIR demand forecast, table 7.1 (confidential).

Figure 6.9: Total regional GRP as proportion of Queensland GSP



Source: Ergon Energy, *Revised regulatory proposal*, Attachment RP970c *NIEIR demand forecast*, table 4.1 (confidential).

The AER also notes that MMA's analysis of historic data shown Ergon Energy's system maximum demand closely correlated with Queensland GSP (see figure 6.7).

The AER accepts that growth in the resource sector could potentially drive up electricity demand in terms of both energy sales and maximum demand, with the expectation that the extent of the impact would be larger on the energy sales rather than maximum demand. The AER also expects the demand growth associated with the expansion of the resource sector to be reflected through increases in temperature insensitive load (base load).

The AER notes that Ergon Energy did not provide sufficient evidence to quantify the expected increase in maximum demand associated with the expansion of the resource sector, but instead stated the impact will be accounted for in the NIEIR model. Ergon Energy stated that it has chosen the NIEIR model because it provides both regional and sectoral forecasts to account for Queensland's regional economic growth as well as the sectoral composition of the regional economy.[176]

The AER notes that the NIEIR's forecast growth in system maximum demand appeared to be driven by growth in both base load and temperature sensitive loads as shown in figure 6.4, with average base load growth forecast to be around 2.3 per cent per year over the period 2009–10 to 2014–15 compared to 2.8 per cent observed over recent years.[177] The AER however observed a step change in NIEIR's forecast of

176 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 71.

177 Calculated based on Ergon Energy, *Revised regulatory proposal*, attachment RP 970c NIEIR 2009 demand forecast, table 7.1.

temperature sensitive demand in 2012, which is unlikely to be related to growth in the resource sector (see figure 6.4).[178]

The AER notes Ergon Energy stated in the revised proposal that it has reconciled its bottom up forecast with NIEIR's top down forecast developed based on econometric and demographic forecasts and therefore has properly taken account of changes in key drivers.[179]

Irrespective of the reasonableness of NIEIR's forecast, the AER notes that there are substantial differences between NIEIR and Ergon Energy's forecasts at a regional level, particularly in North Queensland, South West, and Wide Bay.[180] Therefore, the AER has seen no evidence of systematic reconciliation between NIEIR's and Ergon Energy's forecasts at the regional level.

The AER notes that Powerlink suggested in its submission to the AER that the potential introduction of the carbon pollution reduction scheme (CPRS) should not be factored into the demand forecasts given its uncertainty.[181] The AER also notes that while MMA considered that the potential introduction of the CPRS should be given some consideration, its impact on maximum demand is difficult to quantify and therefore has not included this impact in its indicative system maximum demand forecast.[182] The AER considers there are merits in the above arguments, and given the lack of Queensland specific analysis on this issue, the AER accepts that the potential impacts associated with the introduction of the CPRS should be removed from the maximum demand forecasts.

Conclusion

The AER considers that it is reasonable to address Ergon Energy's bottom up demand forecast deficiencies using a top down approach.

Based on MMA and the AER's review of NIEIR's top down system maximum demand forecast, the AER considers it is inappropriate to use NIEIR's forecast for adjusting Ergon Energy's bottom up forecast.

The AER has previously considered MMA's top down system maximum demand forecast model and concluded that the methodology used is reasonable. The AER reviewed the input assumptions used by MMA to update its model including revised GSP, dwelling, and air conditioner forecasts. The AER considered these input forecasts to be reasonable, and that the forecasts produced with this model (see table 6.11) provide a more accurate forecast of Ergon Energy's system maximum demand than Ergon Energy's methodology.

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178 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 13.

179 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 74–75.

180 Calculated based on Ergon Energy, *Revised regulatory proposal*, attachment RP929c_EE_Region BSP & CP 2009 Forecast_23Dec09, and attachment RP 970c NIEIR 2009 demand forecast, table 9.1–9.6.

181 AER, *Minutes of the Queensland public forum on Energex's and Ergon Energy's draft distribution determinations*, 8 December 2009.

182 MMA, *Review of Energex's maximum demand forecasts for the 2010–15 price review*, October 2009, p. 32; and MMA, Response to AER questions and comments about review of Ergon demand forecasts, March, 2010.

Table 6.11: MMA updated forecast of Ergon Energy 50% PoE system maximum demand

	2010–11	2011–12	2012–13	2013–14	2014–15
MMA March 2010 forecast	2778	2907	3017	3100	3171
MMA October 2009 forecast	2693	2811	2928	3031	3121
Ergon Energy revised forecast	2799	3052	3181	3282	3365

Source: MMA, *Maximum demand forecast for Ergon Energy region – update*, March 2010, p. 27.

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised proposal, MMA's report and other material, the AER was not satisfied that Ergon Energy's forecast of maximum demand provides a realistic expectation of the demand forecast required to achieve the capex and opex objectives. The AER considers that reducing Ergon Energy's forecast maximum demand to the levels shown in table 6.11 provides a more realistic basis for determining capex and opex forecasts that would comply with the NER.

6.6 AER conclusion

The AER considered that the revised system maximum demand forecasts proposed by Energex did not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the NER.

The AER considered that the customer number and energy consumption forecasts proposed by Energex provided a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the NER.

The AER's conclusions on Energex's maximum demand, energy consumption and customer number forecasts over the next regulatory control period are set out in table 6.12. The amounts determined by the AER have been amended from Energex's revised regulatory proposal only to the extent necessary to enable it to be approved in accordance with the NER.

Table 6.12: AER conclusions on Energex maximum demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 [a]
Maximum demand (MW)	4931	5089	5328	5555	5733	3.8%
Customer numbers	1 363 138	1 389 033	1 417 664	1 448 548	1 480 294	2.1%
Energy consumption (GWh)	22 416	23 138	24 042	24 795	25 845	3.6%

(a) Average annual growth rate calculated based on 2010–11 to 2014–15 data.

The AER considered that the revised system and spatial maximum demand forecasts proposed by Ergon Energy did not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the NER.

The AER considered that the customer number and energy consumption forecasts proposed by Ergon Energy provided a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the NER.

The AER's conclusions on Ergon Energy's maximum demand, energy consumption and customer number forecasts over the next regulatory control period are set out in table 6.13. The amounts determined by the AER have been amended from Ergon Energy's revised regulatory proposal only to the extent necessary to enable it to be approved in accordance with the NER.

Table 6.13: AER conclusions on Ergon Energy's maximum demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15[a]
Maximum demand (MW)	2778	2907	3017	3100	3171	3.4%
Customer numbers	684 469	695 242	706 204	717 356	728 706	1.6%
Energy consumption (GWh)	15 871	16 450	16 874	17 433	17 887	3.0%

(a) Average annual growth rate calculated based on 2010–11 to 2014–15 data.

6.7 AER decision

In accordance with clause 6.12.1(10) the other appropriate amounts, values or inputs to be input to the PTRM for Energex are the AER maximum demand, customer number and energy consumption forecasts specified in table 6.12 of this decision.

In accordance with clause 6.12.1(10) the other appropriate amounts, values or inputs to be input to the PTRM for Ergon Energy are the AER maximum demand, customer number and energy consumption forecasts specified in table 6.13 of this decision.

7 Forecast capital expenditure

This chapter sets out the AER's consideration of issues raised in response to the draft decision on forecast capex for the Qld DNSPs. It also sets out the AER's conclusion on forecast capex for the Qld DNSPs for the next regulatory control period.

7.1 AER draft decision

Energex

The AER considered Energex's proposed forecast capex allowance of $6466 million and was not satisfied that Energex's forecast capex reasonably reflected the capex criteria. In coming to this view the AER had regard to the capex factors.[183]

The AER was not satisfied that Energex's growth capex reflected a realistic expectation of demand, or that proposed cost escalators adequately accounted for the global financial crisis (GFC) to reflect a realistic expectation of cost inputs. Further, the AER considered that Energex's proposed non–system capex on major building projects had not been demonstrated to be prudent and efficient.[184]

Following its review of Energex's capex proposal the AER made the following adjustments:[185]

- $372 million reduction to total capex (related to cost escalators)
- $289 million reduction to growth capex
- $158 million reduction to non–system capex
- $7 million reduction in indirect costs associated with information, communications and telecommunications (ICT) services.

The AER was satisfied that an estimate of $5718 million for Energex's forecast capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered this reduction was the minimum adjustment necessary to ensure Energex's capex forecast met the capex criteria. The AER's draft conclusion is shown in table 7.1.

183 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 128.
184 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 128.
185 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 128.

Table 7.1: AER draft 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 that were included in growth capex and non–system capex deductions	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

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 129.
Notes: Totals may not add due to rounding.
The indirect costs included in deductions to growth and non–system capex should not 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.

Ergon Energy

The AER considered Ergon Energy's proposed forecast capex allowance of $6033 million and was not satisfied that Ergon Energy's forecast capex reasonably reflected the capex criteria. In coming to this view the AER had regard to the capex factors.[186]

The AER did not consider Ergon Energy's proposed growth capex reflected a realistic expectation of the demand forecast required to achieve the capex objectives. The AER also considered that Ergon Energy's proposed asset replacement capex did not reflect efficient costs.[187]

The AER considered that Ergon Energy's proposed reliability and quality improvement capex, in particular the feeder improvement program, had not been demonstrated to be prudent and efficient. Further, the AER considered the expenditure associated with Ergon Energy's major building projects and the ICT systems change program had not been demonstrated to be prudent and efficient.[188]

Following its review of Ergon Energy's capex proposal the AER made the following adjustments:[189]

- $844 million reduction to growth capex

[186] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 128.
[187] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 129.
[188] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 129.
[189] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 129.

- $119 million reduction to asset replacement capex
- $35 million reduction to reliability and quality improvement capex
- $39 million reduction in shared costs associated with ICT services, sponsorship and community engagement
- $253 million reduction to non–system capex
- $82 million increase to total capex to account for errors in the application of input cost escalators.

Following the adjustments outlined above, and as detailed in table 7.2, the AER was satisfied an estimate of $5013 million[190] for Ergon Energy's forecast capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered this reduction was the minimum adjustment necessary to ensure Ergon Energy's capex forecast met the capex criteria. The AER's draft conclusion is shown in table 7.2.

Table 7.2: AER draft conclusion 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 that were included in growth, asset replacement, reliability and non–system capex deductions	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

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 130.
Notes: Totals may not add due to rounding.
The shared costs included in deductions one to four above should not be removed from Ergon Energy's capex allowance. This is because, with the exception of an adjustment for ICT services, the AER has not proposed any adjustments to Ergon Energy's shared costs.

[190] Ergon Energy advised the AER on 8 March 2010 that the total capex allowance set out in the draft decision was incorrect due to modelling errors. Ergon Energy advised a corrected figure of $4992 million ($2009–10).

7.2 Revised regulatory proposals

Energex

Energex's revised regulatory proposal included a capex allowance of $6069 million ($2009–10) for the next regulatory control period.[191] Energex subsequently submitted a revised approach to cost escalation, which increased its proposed capex allowance to $6286 million ($2009–10).[192] Energex's revised capex proposal is set out in table 7.3.

Table 7.3: Energex's original and revised capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Original capex	1239.5	1269.7	1301.9	1292.4	1362.5	6466.0
Revised capex	1232.1	1275.1	1265.0	1238.5	1275.7	6286.3
Difference	–7.4	5.5	–37.0	–54.0	–86.8	–179.6

Source: Energex, *Regulatory proposal*, June 2009, RIN template 2.2.1; and Energex, *Revised regulatory proposal*, January 2010, RIN template 2.2.1, confidential.
Note: Totals may not add due to rounding.

Energex did not accept the findings of the draft decision in relation to growth capex, non–system capex and indirect capex costs.[193]

Energex's revised capex proposal of $6286 million is approximately $180 million lower than its original capex proposal. Table 7.4 shows the annual profile of Energex's revised capex proposal by system and non–system capex categories.

Table 7.4: Energex's revised capex proposal by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
System capex	1040.2	1147.8	1165.2	1174.6	1191.8	5719.6
Non–system assets	191.9	127.4	99.8	63.8	83.9	566.7
Revised total capex	1232.1	1275.1	1265.0	1238.5	1275.7	6286.3

Source: Energex, *Response to AER.EGX.RP.11*, 10 March 2010, confidential.
Note: Totals may not add due to rounding.

Ergon Energy

Ergon Energy included a capex allowance of $6274 million ($2009–10) for the next regulatory control period.[194] Ergon Energy's revised capex proposal is set out in table 7.5.

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[191] Energex, *Revised regulatory proposal*, January 2010, p. 20.
[192] Energex, *Submission on draft determination for the period July 2010–June 2015*, February 2010.
[193] Energex, *Revised regulatory proposal*, January 2010, p. 13.
[194] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 99.

Table 7.5: Ergon Energy's original and revised capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Original capex	1086.2	1199.9	1177.3	1228.0	1341.5	6032.9
Revised capex	1123.2	1222.1	1232.0	1293.5	1403.4	6274.1
Difference	37.0	22.2	54.7	65.4	61.9	241.2

Source: Ergon Energy, *Regulatory proposal*, June 2009, RIN template 2.2.1 and Ergon Energy, *Revised regulatory proposal*, January 2010, RIN template 2.2.1.
Note: Totals may not add due to rounding.

Ergon Energy did not accept the findings of the draft decision, except in relation to sponsorship and community engagement capex and, in part, non–system ICT capex and input cost escalation.[195]

Ergon Energy's revised capex proposal of $6274 million is approximately $241 million higher than its original capex proposal. Table 7.6 shows the annual profile of Ergon Energy's revised capex proposal by category.

Table 7.6: Ergon Energy's revised capex proposal by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Asset replacement	181.2	222.6	261.7	285.9	305.0	1256.4
Corporation initiated augmentation	273.3	355.8	423.0	487.9	536.3	2076.3
Customer initiated capital works	363.7	394.7	641.8	357.3	389.0	1846.5
Reliability and quality improvement	18.5	21.5	25.2	29.0	30.8	125.0
Other system	111.1	75.0	53.1	52.7	53.2	345.1
Non–system assets	175.4	152.6	127.3	80.7	89.0	625.0
Revised total capex	1123.2	1222.1	1232.0	1293.5	1403.4	6274.1

Source: Ergon Energy, *Revised regulatory proposal*, p. 143.
Note: Totals may not add due to rounding.

7.3 Submissions

The AER received submissions from:

- Cement Australia Pty Limited (Cement Australia)
- EnergyAustralia

[195] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 99–143.

- Energy Users Association of Australia (EUAA)
- Maryborough Sugar Factory Limited
- Queensland Council of Social Service (QCOSS)
- Total Environment Centre (TEC)
- UnitingCare Australia (UnitingCare).

Benchmarking

Submissions from Cement Australia, the Maryborough Sugar Factory and the EUAA urged the AER to use benchmarking to help establish an efficient level of network costs.[196] The submission from EnergyAustralia supported the view that the role of benchmarking is to test the reasonableness of a distributor's detailed expenditure proposals, and that it should not be used to set expenditure allowances.[197]

Underutilisation of demand management

TEC submitted that the Qld DNSPs have vastly underutilised the potential of demand management to meet and reduce demand. TEC suggested that the AER should require network businesses to implement demand management as a first choice over network augmentation where equal to or more cost effective than, building new infrastructure.[198] QCOSS submitted that the regulatory framework should allow for much greater innovation and expenditure on alternatives to augmentation.[199] UnitingCare submitted that the provision for demand management in the draft decision could be considered miserly, and that there is significant potential for substantial cost savings for future capex through sensible demand management strategies. UnitingCare proposed that consideration be given to a benchmark for demand management expenditure of 0.2 per cent of expected revenue for distribution businesses.[200]

AER reliance on processes, procedures and governance frameworks

The EUAA is concerned that the AER's reference to processes, procedures and governance frameworks in assessing capex proposals does not provide an appropriate basis for determining efficient expenditure. The EUAA submitted that the AER should apply a greater use of benchmarking to assess efficiency of proposed capex.[201]

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196 Cement Australia, *AER review of electricity distribution prices in Queensland*, 16 February 2010, p. 3; Maryborough Sugar Factory, *AER review of electricity distribution prices in Queensland*, 23 February 2010, p. 1; and EUAA, *Submission to the AER on its draft decision for the regulated revenues to be applied to Energex and Ergon Energy in the period 1 July 2010 to 30 June 2015*, February 2010, p. 19.

197 EnergyAustralia, *EnergyAustralia submission on ERS draft determinations for Queensland and South Australia*, 16 February 2010, p. 1.

198 TEC, *Submission to the AER on Queensland draft distribution determination 2010–11 to 2014–15*, 18 February 2010, pp. 2–3.

199 QCOSS, *Submission on the AER draft decision – Queensland distribution determination process 2010–2015*, February 2010, p. 3.

200 UnitingCare, *Submission to the AER on distribution price reviews*, February 2010, pp. 11–12.

201 EUAA, *Submission to the AER on Qld DNSPs*, February 2010, pp. 13–15.

Unit costs

The EUAA criticised the AER's assessment of capex unit costs for the Qld DNSPs. The EUAA stated that one of the key elements in the preparation of a capex program is to cost the key components of the electricity network. The EUAA stated that PB did not assess the DNSPs' unit costs and that the AER should have done this itself. The EUAA considered that the assessment was not an independent, robust and transparent way to review capex.[202]

Other system capex (UbiNet project)

The EUAA submitted that the AER relied on an unsupported assertion that the Ubiquitous Network (UbiNet) project was economically beneficial in order to allow this expenditure in its draft decision. The EUAA also submitted that it was unacceptable that the costs of this project were unavailable.[203]

Current regulatory control period capex overspend

The EUAA submitted that the AER should examine the historical capex overspend of the Qld DNSPs in the current regulatory control period to ensure expenditures were incurred efficiently.[204]

7.4 Issues and AER considerations

7.4.1 Issues raised in submissions

Benchmarking

The AER has addressed submissions relating to the AER's use of benchmarking in appendix G of this decision.

Underutilisation of demand management

The AER has addressed submissions relating to demand management in chapter 14 of this decision.

AER assessment methodology

The AER notes the view of the EUAA that the AER's reliance on processes, procedures and governance frameworks, and its consultant's view of what constitutes 'good electricity industry practice' does not provide an appropriate basis for determining efficient expenditure.[205]

As the EUAA recognises in its submission, it is not possible for the AER to undertake a detailed review of every possible program and project included as part of a DNSP's capex proposal. The AER therefore places substantial weight on the information provided by the DNSP in support of its proposed capex in terms of capex policies and procedures, governance frameworks, key assumptions, cost estimation methodologies, demand forecasts and real cost escalators to assist in determining whether it is

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[202] EUAA, *Submission to the AER on Qld DNSPs*, February 2010, section 4.3.1, p. 15.
[203] EUAA, *Submission to the AER on Qld DNSPs*, February 2010, pp. 16–17.
[204] EUAA, *Submission to the AER on Qld DNSPs*, February 2010, pp. 17–19.
[205] EUAA, *Submission to the AER on Qld DNSPs*, February 2010, pp. 13–15.

satisfied the forecast capex reasonably reflects the capex criteria listed in clause 6.5.7(c) of the NER.[206]

In response to the EUAA's query regarding the meaning of the term 'good electricity industry practice' (as used by PB), the AER notes that this term is defined in chapter 10 of the NER. The AER agrees with the EUAA that notions of efficiency and good electricity industry practice are not one and the same. The AER does, however, consider that the question of whether a DNSP's policies and practices are in accordance with good electricity industry practice is a relevant consideration when assessing the efficiency of costs determined on the basis of those policies and practices.

Unit costs

The AER agrees with the EUAA that unit costs are an important aspect of a DNSP's capex forecasts. However, the AER disagrees with the EUAA's suggestion that the AER should have assessed the DNSPs' unit costs itself.

The AER notes the EUAA's comment that PB had no specific requirement to benchmark unit costs.[207] As described in PB's reports on the DNSPs' proposals, and in the draft decision, PB's high-level analysis did not identify any issues in relation to the Qld DNSPs' unit costs that it considered warranted further investigation. The AER therefore formed the view that PB was not required to assess unit costs in detail where this was not warranted by the high-level review. It is incorrect to say that PB was not required to assess unit costs in detail where this was considered necessary.

Other system capex (UbiNet project)

The AER notes the EUAA's view that the AER relied on an unsupported assertion that the UbiNet project was economically beneficial in order to allow this expenditure in its draft decision, and that the costs of this project should be available.[208] In this regard, the AER notes that PB's original report concluded that, on current cost estimates, the business case for this project demonstrates that UbiNet is an economically justified investment. PB noted the Queensland Treasury Corporation's conclusion that the economic benefit of the project was $8.6 million on a net present cost of the project of $132.7 million.[209] The AER gave consideration to PB's assessment and formed the view that the UbiNet project was economically beneficial.

Current regulatory control period capex overspend

The EUAA submitted that the AER should examine the historical capex overspend of the Qld DNSPs in the current regulatory control period to ensure expenditures were incurred efficiently.[210]

The AER notes that an ex–post review of the prudence and efficiency of historical capex does not form part of its distribution determinations for DNSPs under the NER. The AER undertook a review of capex outcomes from the current regulatory control

206 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 84.
207 EUAA, *Submission to the AER on Qld DNSPs*, February 2010, section 4.3.1, p. 15.
208 EUAA, *Submission to the AER on Qld DNSPs*, February 2010, pp. 16–17.
209 PB, *Report – Ergon Energy*, October 2009, p. 64.
210 EUAA, *Submission to the AER on Qld DNSPs*, February 2010, pp. 17–19.

period in order to ensure that the capex proposals accounted for the drivers of cost variations in the current regulatory control period.[211]

7.4.2 Cost escalators

AER draft decision

The AER did not accept the methodologies used to develop the Qld DNSPs' real cost escalators.

The AER considered Energex's escalation rates for labour costs were not acceptable because the proposed constant wage growth forecasts did not accurately represent the volatility of the current market and the forecasts did not reflect the most recently available data. The AER considered Energex's escalation rates for materials costs were not acceptable because they did not reflect actual and forecast changes in materials costs, most notably significant decreases in materials costs in 2008–09 and 2009–10. Energex's forecast capex was consequently reduced by $372 million ($2009–10).[212]

The AER did not consider Ergon Energy's application of a single escalation rate to internal and contract labour costs was appropriate because it diminished the commercial incentive for Ergon Energy to negotiate competitive wage outcomes and it did not differentiate between specialist and general labour resources.

The AER considered Ergon Energy's escalation rates for materials costs were not acceptable because they did not reflect the most up to date market–based forecasts of future materials costs. The AER identified two errors in relation to how Ergon Energy had applied its cost escalators in calculating forecast capex. Due to these errors, Ergon Energy's forecast capex was increased by $82 million ($2009–10).[213]

Revised regulatory proposal

Energex

Energex applied the escalation rates calculated by the AER for its draft decision and indicated that it expected the AER to update these to reflect data available at the time of the final decision.[214] Energex noted that it did not necessarily accept the rationale behind all of the AER's adjustments and that it would provide further comment on escalators in its submission to the AER.[215]

Application of the escalators proposed by the AER resulted in forecast capex for the next regulatory control period of $6069 million in Energex's revised proposal.[216]

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211 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 85–87.
212 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 123.
213 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 124.
214 Energex, *Revised regulatory proposal*, January 2010, p. 18.
215 Energex, *Revised regulatory proposal*, January 2010, p. 1.
216 Energex, *Revised regulatory proposal*, January 2010, p. 20.

Ergon Energy

Ergon Energy did not agree with certain aspects of the AER's approach to cost escalation, including adjustments in relation to how Ergon Energy applied escalators for real cost inputs as well as adjustments to the calculation of the real cost inputs.

Ergon Energy rejected the AER's adjustment in relation to using the same CPI to inflate and deflate values in its cost escalation process for capex. Ergon Energy stated that if it adopted this approach, the nominal values of Ergon Energy's capex would be understated. Ergon Energy therefore reinstated the approach used in its regulatory proposal.[217]

Ergon Energy also raised concerns about the AER's approach to calculating escalation rates for real cost inputs. More detailed discussion of real cost escalators is included in appendix F.

Ergon Energy did not accept the adjustments to labour cost escalators made by the AER, in part because the AER had not demonstrated that Ergon Energy's proposed escalation rates were outside a reasonable range.[218] As a result, Ergon Energy reinstated the escalators it applied in its regulatory proposal. These were the same for both internal labour and contract labour and reflected Ergon Energy's Union Collective Agreement (UCA).[219]

Ergon Energy accepted the changes to the calculation of materials cost escalators made by the AER, with the following exceptions:

- the use of London Metal Exchange (LME) 63 month and 123 month forward contract prices for aluminium and copper[220]
- the removal of the trade weighted index (TWI) from the calculation of materials costs escalators.[221]

Submissions

Energex provided a detailed proposal on cost escalation in its submission.[222] The approach to cost escalation proposed by Energex is discussed in more detail in appendix F.

Energex stated that the improving and less volatile economic outlook compared to that at the time of the regulatory proposal allowed greater confidence in data based forecasting methods. On this basis, Energex prepared updated cost escalation forecasts for labour, materials and construction.[223]

Energex raised concerns about the labour cost forecasts provided by Access Economics, including that the underlying modelling was not sufficiently

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217 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 136.
218 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 87.
219 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 97.
220 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 137.
221 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 138.
222 Energex, *Submission on draft determination*, February 2010.
223 Energex, *Submission on draft determination*, February 2010, p. 3.

transparent.[224] In addition, Energex disagreed with the AER's use of different escalation rates for internal staff and external contractors[225] and how the AER had accounted for the impact of its UCA.[226] Energex proposed that PricewaterhouseCoopers' labour cost escalation forecasts should be used in the final decision for internal staff and external contractors.[227]

Energex engaged SKM to produce materials cost escalators that included weightings that reflect the underlying cost drivers of Energex's capex program.[228] Energex noted that it considered long term LME futures markets for aluminium, copper and steel were not sufficiently liquid to provide robust forecasts.[229] Instead, Energex stated that SKM's use of economic consensus prices better reflects the capex and opex criteria and objectives.[230]

Energex provided updated estimates of building and construction cost escalators based on the latest forecasts from the Construction Forecasting Council (CFC).[231]

Application of the escalators proposed by Energex in its submission to the capex forecasts in Energex's revised regulatory proposal resulted in forecast capex of $6286 million for the next regulatory control period, up from $6069 million in its revised regulatory proposal.[232]

Consultant review

Labour

The AER engaged Access Economics to provide an update on its growth forecasts for general state labour price indices (LPIs) and the electricity, gas and water (EGW) sector in NSW, Victoria, Queensland, South Australia, ACT and nationally.[233] Access Economics noted changing economic conditions were the key driver for revisions to forecasts published in its September 2009 report[234] and that a number of technical changes to historical variables have also impacted the forecasts.[235]

Access Economics projected Queensland's economic growth to slow over the next 18 months due to the combination of anticipated falls in engineering activity, commercial and housing construction weaknesses, alongside the lagged impact of actioning construction decisions to construction activity. Access Economics considered that while Queensland's EGW wage growth may experience further

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224 Energex, *Submission on draft determination*, February 2010, p. 8.
225 Energex, *Submission on draft determination*, February 2010, p. 12.
226 Energex, *Submission on draft determination*, February 2010, p. 11.
227 Energex, *Submission on draft determination*, February 2010, p. 12.
228 Energex, *Submission on draft determination*, February 2010, p. 5.
229 Energex, *Submission on draft determination*, February 2010, pp. 4–5.
230 Energex, *Submission on draft determination*, February 2010, p. 5.
231 Energex, *Submission on draft determination*, February 2010, p. 7.
232 Energex, *Response to AER question AER.EGX.RP.04*, 5 March 2010, confidential.
233 Access Economics, *Forecast growth in labour costs: March 2010 report,* 16 March 2010.
234 Access Economics, *Forecast growth in labour cost,* 16 September 2009.
235 Access Economics, *Forecast growth in labour cost,* 16 September 2009, p. 35. See Appendix F for further information on the conversion of ANZSIC93 to ANZSIC06.

weakness in the first half of 2010, data indicates wage growth is likely to revert to be slightly above the national average from 2011.[236]

Access Economics general labour forecasts are set out in table 7.7 below.

Table 7.7: Access Economics real labour escalation rates for general labour and the EGW sector in Queensland.

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
General	0.4	0.5	0.2	0.4	0.9	1.4	1.5
EGW	1.1	1.1	1.0	0.9	1.3	1.5	1.6

Source: Access Economics, *Forecast growth in labour costs*, March 2010, p. 69.

Materials

PB was not required to assess forecast rates of growth in input costs (this exercise has been undertaken by the AER and is described in detail in appendix F), but it was required to ensure that forecast changes in input costs were appropriately reflected in the cost escalation calculations performed by the Qld DNSPs in forecasting capex.

PB reviewed two issues in relation to the application of cost escalators:

- cost weightings associated with Energex's proposed new materials cost escalator
- Ergon Energy's response to PB's original recommendation to use the same CPI to inflate and deflate values in its cost escalation process.

Energex

Energex proposed a new approach to forecasting materials costs in its submission. PB assessed whether the approach included appropriate weightings of real input costs to produce the composite materials cost escalator for Energex's capex forecasts.

PB noted that SKM established the cost input weightings by applying a set of expenditure based category-level weightings within its database to Energex's asset categories. In order to assess these weightings, PB calculated a comparable set of weightings based on its understanding of DNSPs' project costs and components.[237]

PB considered that its estimates of component weightings were sufficiently similar to those developed by SKM to conclude that the weightings were reasonable and suitable for use in the forecasting of Energex's capex.[238]

Ergon Energy

PB noted that the impact of using the same CPI series to inflate and deflate expenditure in Ergon Energy's capex model resulted in a reduction in the forecast allowance of $20.4m.[239]

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236 Access Economics, *Forecast growth in labour costs,* March 2010, pp. 70–71.
237 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 5.
238 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 6.

PB noted that Ergon Energy's approach was aimed at ensuring that the nominal capex values calculated in the post–tax revenue model (PTRM) were the same as the nominal forecasts of capex in its capex model.[240] PB stated its understanding that the calculation of forecast capex is essentially separate from the calculations undertaken in the PTRM and that there was no requirement to align the CPI values between the two calculations.[241]

On this basis, PB recommended that in order to correctly calculate Ergon Energy's required capex in 2009–10 real values, Ergon Energy should use its forecast CPI values consistently to inflate and deflate real and nominal values respectively. In addition, PB noted that in order to avoid the two separate stages of inflation and deflation, it would be possible to inflate Ergon Energy's 2007–08 real values directly to 2009–10 real values using Ergon Energy's forecast CPI values.[242]

AER considerations

The details of the AER's assessment of the cost escalators proposed by the Qld DNSPs are set out in appendix F of this decision.

Labour

The AER notes that the Qld DNSPs raised a number of concerns in relation to the modelling undertaken by Access Economics, the AER's recognition of impacts arising from the UCAs, and the use of different escalation rates for internal labour and external contractors.

The AER is satisfied that Access Economics' methodology for forecasting labour costs growth is robust given the application of its formal econometric modelling approach.[243] The AER also considers the Access Economics model is adequately supported by information contained in Access Economics' reports (September 2009 and March 2010) and is further supported by information discussing the concordance between ANZSIC93 and ANZSIC06.[244] Further, the AER has reviewed Access Economics model documentation (version 6)[245] and is satisfied information supporting Access Economics' equations, parameters and variables is well documented and robust. The AER considers that the components of Access Economics' model have been correctly applied and that results have been correctly interpreted.

The AER notes that the Qld DNSPs raised issues in relation to how wage increases under their respective UCA's should be applied. For example, Energex queried the calculation of UCA impacts for 2008–09, 2009–10 and 2010–11, citing a mixture of actual and forecast data which caused underestimates of the escalation rates.[246] The AER reviewed its modelling and confirms that actual and forecast data was not mixed

239 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 52.
240 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 52.
241 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 52.
242 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 52.
243 See AER, *Draft decision, Queensland draft distribution determination,* November 2009, p. 605 for an overview of the AEM approach.
244 Access Economics, *Forecast growth in labour costs,* March 2010, Appendix F.
245 Full AEM model documentation was provided to the AER on a commercial-in-confidence basis.
246 Energex, *Submission on draft determination,* February 2010, p. 10.

in calculating the rates for 2008–09 and 2009–10. However, the 2010–11 rate included UCA impacts. The inclusion of UCA impacts was a modelling error. The AER confirms the draft decision that it is reasonable to adopt current UCA wage increases up until 2009–10 only, in order to maintain the incentives on DNSPs to negotiate efficient labour outcomes. The AER has corrected the modelling error in relation to UCA impacts in 2010–11 for this decision.

Notwithstanding the AER's view that UCA rates should not automatically be reflected in the escalation rates for the next regulatory control period, the AER also considers that the rates themselves do not provide a realistic expectation of the Qld DNSPs' labour costs in the next regulatory period. This is because, as discussed in appendix F, the current UCAs came into effect prior to the global financial crisis (GFC),[247] and therefore would not reflect the impact and uncertainty of GFC associated economic conditions on labour growth.

The AER considers that internal labour cost escalators should not be applied to contract labour costs because, as discussed in appendix F, contractors do not form part of the internal, full-time or on-going workforce to which awards generally apply and the proportions of technical and general labour in the internal and contract labour forces of the DNSPs differ.

Construction costs

The AER notes that the Qld DNSPs accepted the AER's approach to deriving construction cost escalators. As foreshadowed in the draft decision, the AER considers that to develop a robust forecast it is appropriate to update the forecast construction cost escalators using the most recent data. The AER therefore considers it appropriate to apply the updated construction cost forecasts from CFC.[248]

Materials

The AER considers that the method adopted by the Qld DNSPs, with the exception of the TWI component, provides a realistic expectation of the real materials costs required for the Qld DNSPs to achieve the capex objectives in the next regulatory control period.

The AER's conclusions are discussed in detail in appendix F. The AER notes the concerns raised by the Qld DNSPs in relation to using LME 63 month and 123 month contract prices to calculate escalation rates for aluminium and copper. The AER has reviewed LME price data and confirmed that prices for 63 month and 123 month futures contracts are unofficial and do not reflect outcomes from a liquid market. As a result, the AER considers it inappropriate to use this data and accepts the proposal by the Qld DNSPs to use Consensus Economics long term forecasts to establish cost escalators for aluminium and copper.

[247] The AER notes a paper published by the Australian Government – The Treasury, *Australia's response to the global financial crisis*, www.treasury.gov.au, accessed 22 February 2010, stated the key turning point for the Australian economy was the change that swept through the global economy in mid–September 2008.

[248] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 599.

The AER does not accept inclusion of the TWI in the cost escalation proposed by the Qld DNSPs because it recognises TWI-related cost increases prior to the regulatory control period but provides no possibility of capturing cost decreases during the regulatory control period. This is because the TWI has been assumed to be fixed for the regulatory control period, in the absence of a recent publicly available forecast developed by a reputable source.[249] The AER considers that to allow the inclusion of the TWI as proposed by the Qld DNSPs would lead to an asymmetric treatment of costs. Specifically, DNSPs would include factors such as the TWI in their cost escalation proposals where historical data indicated higher costs, while omitting factors for which historical data indicated lower costs.

Weighting of Energex's materials costs

Regarding the materials cost weightings proposed by Energex, the AER notes PB's conclusion that they are sufficiently similar to comparator weightings developed by PB to conclude that they are reasonable and suitable to forecast Energex's capex materials costs. The AER considers that the weightings developed by Sinclair Knight Merz Pty Ltd (SKM) and PB are likely to provide a better basis for cost escalation than the weightings used by the AER in the draft decision, which reflected the costs of only two DNSPs.

Application of CPI by Ergon Energy

Regarding the CPI series used by Ergon Energy to calculate its capex forecasts, the AER notes that PB confirmed that Ergon Energy should use the same forecasts of CPI to inflate and deflate real and nominal values respectively. The AER also notes PB's observation that in order to avoid the two separate stages of inflation and deflation undertaken by Ergon Energy in its capex modelling, it would be possible to inflate Ergon Energy's 2007–08 real values directly to 2009–10 real values using Ergon Energy's forecast CPI values. The AER raised this issue with Ergon Energy and asked it to provide revised CPI values for 2008–09 and 2009–10 if it considered the values in its capex model did not, on their own, result in the appropriate conversion of 2007–08 costs into 2009–10 values. Ergon Energy did not provide amended CPI values as requested.[250]

For the reasons discussed the AER considers that the appropriate $2009–10 capex values are those that result from the application of the 2008–09 and 2009–10 CPI values in Ergon Energy's capex model. To be clear, the AER does not consider it appropriate to make any further adjustments to these 2009–10 values as a result of further inflation and deflation of the values using different CPI series, as proposed by Ergon Energy.

The AER considers that to develop a robust forecast it is appropriate to update the forecast materials cost escalators using the most recent data.[251] The AER considers that this and the adjustments discussed in detail in appendix F are the minimum

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[249] Energex, *Submission on Draft Determination, Appendix 1.0 – Energex materials and cost escalation forecasts for 2010-15, Sinclair Knight Merz*, February 2010, p. 22; and Ergon Energy, *Response to AER.ERG.RRP.19 – Cost escalators, SKM Internal Memo,* 5 March 2010, p. 3.

[250] Ergon Energy, *Response to AER question AER.ERG.RRP.18 – Cost Escalators*, 5 March 2010.

[251] AER, *Draft decision*, *SA Draft distribution determination*, 25 November 2009, p. 458.

adjustments necessary to ensure that the real cost escalators used by the Qld DNSPs provide a realistic expectation of real capex materials costs.

AER conclusion

Table 7.8 sets out the AER's conclusions on the Qld DNSPs' real escalators over the next regulatory control period. More detailed information on the AER's assessment is in appendix F of this decision.

Table 7.8: AER conclusion on the Qld DNSPs' real cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Escalators applying to both DNSPs							
Aluminium	–18.76	–6.96	23.00	–1.20	0.40	–2.62	–3.58
Copper	–27.33	17.42	20.03	–5.42	–4.19	–7.48	–8.63
Steel	7.09	–28.29	33.03	1.00	0.80	–2.29	–3.25
Crude oil	–17.34	–3.69	25.80	–2.97	0.24	–1.74	–2.46
Exchange rates	0.744	0.856	0.721	0.738	0.725	0.728	0.738
Inflation rate	1.46	3.00	2.50	2.75	2.50	2.50	2.50
Energex							
Materials	–5.05	–5.31	10.71	–0.42	0.11	–1.2	–1.67
Land and easements	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Construction	–0.09	1.90	0.31	1.10	2.66	2.51	0.81
Internal labour	0.12	2.22	0.20	0.86	1.27	1.52	1.63
Contract labour	0.99	0.97	0.83	0.78	1.22	1.50	1.61
Ergon Energy							
Commercial land	4.20	5.50	5.40	5.00	5.00	5.40	5.80
Rural land	6.80	8.10	8.00	7.60	7.60	8.00	8.40
Construction	–0.09	1.90	0.31	1.10	2.66	2.51	0.81
Internal labour	0.18	1.83	0.21	0.75	1.19	1.50	1.60
Contract labour	1.15	1.08	0.98	0.88	1.29	1.53	1.64

Source: AER analysis, except Energex's materials cost escalator, which is a composite based on materials inputs listed in this table – source Energex, response to AER modelling request, 9 April 2010, confidential.

7.4.3 Smart meters

AER draft decision

The AER included a smart meter event as a nominated pass through event for the Qld DNSPs. The draft decision did not explicitly review any forecast expenditures related to smart meters.[252]

Revised regulatory proposals

The Qld DNSPs accepted the draft decision to include a smart meter event as a nominated pass through event.[253]

AER considerations

The AER is aware that there is considerable uncertainty regarding the implementation of smart meters in Queensland. Given the degree of uncertainty that currently exists, the AER considers that it is not reasonable to include smart meter expenditures in the forecast capex and opex allowances for the Qld DNSPs.

In response to a request from the AER, Ergon Energy advised that it had proposed amounts in its opex and capex forecasts for a smart meter pilot.[254] As part of its modelling request, the AER asked Ergon Energy remove any capex or opex related to smart meters contained in its revised regulatory proposal.

Energex advised that it did not include any forecast expenditures in relation to smart meters.

Ergon Energy advised that the adjustment for the removal of smart meter expenditures resulted in a reduction of $5 million ($2009–10) to its capex forecast.[255]

The AER notes that if, during the next regulatory period, the Qld DNSPs have smart meter obligations imposed upon them they may make a pass through application as a smart meter event is listed as a nominated pass through event in this decision (see chapter 15 of this decision).

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal and other information, the AER is not satisfied that Ergon Energy's proposed other system capex forecast relating to a smart meter trial reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing the other system capex forecast by $5 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.

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252 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 337–338.
253 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 201; Energex, *Revised regulatory proposal*, January 2010, p. 49.
254 Ergon Energy, email response to AER, 15 April 2010.
255 Ergon Energy, email response PRP1028c, 22 April 2010.

7.4.4 Energex

7.4.4.1 Growth capex and demand forecasts

AER draft decision

The AER rejected Energex's proposed growth capex of $2613 million. The draft decision was informed by advice from McLennan Magasanik Associates (MMA) that Energex's system peak demand forecasts were overstated to the extent of 200MW to 300MW (approximately one year of peak demand growth). The AER was therefore not satisfied that Energex's forecast demand related growth capex reasonably reflected a realistic expectation of the demand forecast required to achieve the capex objectives.[256]

The AER considered it appropriate that Energex's proposed demand related growth capex be reduced to account for Energex's overestimation of forecast maximum demand in the next regulatory control period.[257]

PB recommended that Energex's proposed demand related growth capex be reduced by 20 per cent in each year of the next regulatory control period, to reflect a smoothed reduction in growth capex equivalent to one year of peak demand related expenditure. In the absence of revised bottom up spatial demand forecasts, the AER considered such an approach to be reasonable for estimating the level of growth capex which reasonably reflects a realistic expectation of forecast demand.[258]

The AER concluded that Energex's growth capex forecast should be reduced by $289 million ($2009–10).

Revised regulatory proposal

Energex did not accept the AER's reduction to proposed growth capex, on the basis that it did not agree with the AER's conclusion that Energex's forecast of maximum demand was overstated.

Energex provided a revised forecast of maximum demand from its consultant, NIEIR, which was prepared in October 2009. This revised demand forecast was substantially the same as the demand forecast which underpinned Energex's original growth capex proposal.[259] Table 7.9 shows Energex's original and revised maximum demand forecasts for the next regulatory control period.

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[256] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 472.
[257] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 472.
[258] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 472.
[259] Energex, *Revised regulatory proposal*, January 2010, p. 14.

Table 7.9: Energex's revised maximum demand forecast for 2010–15 (MW)

	2010–11	2011–12	2012–13	2013–14	2014–15
Maximum demand—regulatory proposal	5126	5338	5633	5844	5941
Maximum demand—revised regulatory proposal	5118	5376	5655	5814	5940
Variation in maximum demand	–8	38	22	–30	–1

Source: Energex, *Revised regulatory proposal*, January 2010, p. 14.

Energex considered the variation in demand forecasts to be immaterial when considered over its entire network, with no impact on the growth capex program proposed in its regulatory proposal. Energex resubmitted its original growth capex proposal, with the exception of the Traveston Dam pump load project, as discussed in section 7.4.4.2 of this decision.[260]

Consultant review

PB reviewed Energex's revised regulatory proposal and other information provided in support of its revised growth capex. PB noted that Energex had resubmitted its original growth capex proposal on the basis that the adjustment to its demand forecast recommended by MMA was not supported and that the revised demand forecast prepared by NIEIR in October 2009 results in negligible change to the forecast maximum demand over the next regulatory control period.[261]

PB noted MMA's conclusion that Energex's arguments in its revised regulatory proposal did not invalidate MMA's demand forecasting methodology or conclusions. PB noted that MMA revised its forecast and found that, while it generally corresponds to Energex's forecast in terms of growth rate, as a result of a lower starting point MMA's forecast remains on average approximately 200 MW, or 3.8 per cent, below Energex's forecast.[262]

PB noted that in its original review it had regard to MMA's advice that Energex's demand forecast was approximately 200 MW to 300 MW above MMA's forecast, and recommended a reduction in growth capex equivalent to a deferral of demand of approximately one year. PB noted that MMA's findings in regard to Energex's revised regulatory proposal also correspond to approximately a one year deferral of Energex's demand forecast.[263]

In calculating its recommended adjustment, PB identified the expenditure related to growth in the corporate initiated augmentation category and reduced the proposed

260 Energex, *Revised regulatory proposal*, January 2010, p. 14.
261 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 3.
262 PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 3–4.
263 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 4.

capex by one fifth in each year, in order to smooth the effect of the one year delay over the five years of the regulatory control period.[264]

On the basis of MMA's advice regarding Energex's demand forecasts, PB recommended a reduction of $262 million ($2009–10) to Energex's revised proposed growth capex, equivalent to a one year deferral of demand.[265] PB's recommendation is set out in table 7.10.

Table 7.10: PB adjustment to Energex's revised growth capex ($2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex revised growth capex proposal[a]	397.4	432.7	483.7	529.6	591.2	2434.6
Corporate initiated augmentation component of growth capex	169.1	199.2	263.8	309.2	370.3	1311.7
PB adjustment	–33.8	–39.8	–52.8	–61.8	–74.1	–262.3
PB recommended growth capex	363.6	392.9	430.9	467.7	517.1	2172.2

Source: PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 4.
Note: Totals may not add due to rounding.
(a) Before the application of Energex's revised cost escalators.

AER considerations

The AER reviewed Energex's revised regulatory proposal in relation to growth capex, and sought advice from PB as to the methodology for, and amount of any adjustment required as a result of MMA's review of Energex's revised maximum demand forecasts.

The advice received from MMA regarding the reasonableness of Energex's demand forecast is discussed in chapter 6 of this decision. The AER examined the material provided by MMA and agrees with MMA's analysis and conclusions. In summary, MMA maintained its view that Energex's maximum demand forecasts are not reasonable and are overstated, when compared with MMA's demand forecasts, to the extent of approximately 200 MW per year.[266]

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

[264] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 4.
[265] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 4.
[266] MMA, *Maximum demand forecasts for the Energex region – update addendum*, March 2010, pp. i–ii.

The AER notes that while Energex disputed the validity of MMA's approach to demand forecasting, its revised regulatory proposal did not dispute the methodology for calculating the adjustment to growth capex set out in the draft decision.[267] The AER notes that PB has recommended the same methodology for calculating the adjustment to growth capex as was adopted in the draft decision.[268] The AER has considered PB's recommendations and agrees with them. Accordingly, the AER considers that it is reasonable, in this decision, to apply the same methodology to calculate any adjustment to Energex's revised growth related capex.

As a result of the AER's consideration of, and agreement with, MMA's advice that Energex's maximum demand forecasts are overstated by approximately 200 MW (that is, the equivalent of one year of forecast maximum demand growth in the next regulatory control period), the AER considers that Energex's proposed demand related growth capex should be reduced by 20 per cent to ensure that this component of the capex forecast reflects a realistic expectation of forecast demand.

AER conclusion

The AER requested Energex model the impact of the AER's decision on proposed growth capex. Energex advised that the adjustment to forecast growth capex is a reduction of $273 million ($2009–10).[269]

For the reasons discussed, and as a result of the AER's consideration of Energex's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's forecast growth capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Energex's proposed demand driven capex by $273 million ($2009–10) 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.

7.4.4.2 Traveston dam pump load project

Revised regulatory proposal

Energex reduced its growth capex forecast for the next regulatory control period by $20 million ($2009–10) for the cancellation of the Traveston dam pump load project, following the decision of the Federal Minister for the Environment, Water, Heritage and the Arts not to allow construction of the Traveston Crossing dam to proceed. Energex did not propose any substitute projects for the next regulatory control period.[270]

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267 Energex, *Revised regulatory proposa*l, January 2010, p. 14.
268 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 4.
269 Energex, response to modelling response, 9 April 2010, confidential.
270 Energex, *Revised regulatory proposal*, January 2010, p. 14.

AER considerations

The AER notes the announcement of the Federal Minister for the Environment, Water, Heritage and the Arts regarding the decision not to approve the proposed Traveston Crossing dam project.[271]

The AER considers that the corporate initiated augmentation (growth) capex originally proposed by Energex for the Traveston dam pump load project in the next regulatory control period is no longer required and should be removed from Energex's capex forecasts. The AER has reviewed Energex's revised regulatory proposal and is satisfied that Energex has appropriately removed the $20 million for Traveston dam pump load project costs from the capex forecast.

7.4.4.3 Non–system capex—major property projects

AER draft decision

The AER concluded that the major property project expenditures proposed by Energex had not been demonstrated to be prudent and efficient. The AER noted that Energex had not provided business case documentation or other supporting documentation to justify the major property project expenditures proposed.[272]

The AER considered that, in the absence of information that adequately established the requirement to replace the [redacted] facility in the next regulatory control period, an allowance for upgrading the facility over a ten year period was more representative of a prudent and efficient level of expenditure.[273]

The AER concluded that Energex's non–system land and buildings capex forecast should be reduced by $158 million ($2009–10). This reflected the removal of all new major building projects proposed to allow for a business as usual level of expenditure plus an allowance for upgrading the [redacted] facility.[274]

Revised regulatory proposal

Energex did not accept the AER's reduction to its proposed land and buildings capex, and resubmitted the capex proposed for the six major property projects. Energex submitted that the projects excluded by the AER represented foundation projects essential for implementation of the corporate property strategy to address Energex's existing and long term property requirements. Energex advised that the projects were required to:[275]

- meet mandatory building, safety and compliance requirements
- address limitations on existing and future operational capacity
- address distribution, logistics and warehousing inefficiencies

[271] Minister for the Environment, Water, Heritage and the Arts, *Media Release – Traveston Dam Gets Final No*, 2 December 2009.
[272] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 492.
[273] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 492.
[274] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 492.
[275] Energex, *Revised regulatory proposal*, January 2010, p. 16.

- address existing community conflicts due to urban encroachment
- reduce excessive maintenance costs on ageing property assets
- meet Energex's long term growth, reliability and efficiency imperatives.

In response to the AER's concern that the major property projects were not supported by business case documentation or other supporting information, Energex submitted its latest corporate property strategic plan for 2010–15, which was endorsed by the Energex Board in December 2009.[276] Energex also provided business case proposals, prepared under Energex's Investment Review Committee capital governance framework, to address the AER's concerns regarding the prudence and efficiency of expenditure on these projects.[277]

Consultant review

PB reviewed Energex's revised regulatory proposal and supporting material provided in relation to the major property projects component of the non–system capex proposal. PB noted that Energex had provided significant new information in support of the proposed land and buildings capex in its revised regulatory proposal, including in relation to the capex approval process, risk assessment analysis, business cases and alternative project options, and project delivery and timing.[278]

PB noted in respect of Energex's approval processes for the major property projects that the processes employed for these projects aligned with those employed by Energex for system capex. These latter processes were previously found by PB to be appropriate. PB noted that the preliminary business cases for major property projects had been endorsed by Energex's Investment Review Committee, but that all projects would be subject to a revised business case and approval when project commencement is requested. PB considered this approval process to be appropriate given the size and nature of the property plan and that this approach demonstrated prudent governance in relation to the property plan.[279]

PB reviewed the quantitative risk assessment analysis conducted for each site by Resource Coordination Partnership (RCP) and the hazard and risk site assessment conducted by AECOM Australia Pty Ltd (AECOM). PB concluded that the methodology employed in these risk assessments was robust and appropriate for the purposes of identifying and prioritising the mitigation of risk relating to Energex's existing property portfolio.[280]

PB reviewed the business cases and alternative project options analysis provided in relation to the proposed six major property projects. PB noted that a 'do nothing' option was included only for the largest expenditure item: the warehousing and logistics facility. PB considered that the absence of analysis of a 'do nothing' option reduced the ability to compare all potential project options or fully understand the

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[276] Energex, *Revised regulatory proposal*, January 2010, p. 15.
[277] Energex, *Revised regulatory proposal*, January 2010, p. 16.
[278] PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 12–13.
[279] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 13.
[280] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 14.

efficiency of the proposed expenditure.[281] However, PB noted that the relevant risk assessments indicated the non–viability of 'business as usual' approaches for the identified property assets. Accordingly, PB was satisfied that Energex's approach was appropriate.[282]

PB conducted a detailed review of the [redacted] facility and noted the following findings regarding the financial analysis of project options:[283]

- the NPV of the preferred option to develop a new facility and dispose of the existing facility was $3 million to $7 million more expensive than the net present value (NPV) of the alternative options

- the property development costs were sourced from independent market information

- the 'do nothing' option included a cost of $10 million for roof replacement and other capex, based on an independent costing provided by AECOM

- the operation cost growth escalator and discount rate represented efficient values which, if applied correctly, should result in reasonable cost comparisons between project options

- the net proceeds from the sale of assets was appropriately included in the analysis.

In relation to the non–financial site options analysis, PB noted that the non–financial risk assessment prepared by RCP demonstrated a strong preference for the option to develop a new facility. PB further noted the site risk assessment report prepared by AECOM indicated that ongoing use of the existing site was undesirable. On the basis of its analysis, PB concluded that the proposed expenditure on the [redacted] facility was prudent. In relation to the other major property projects proposed, PB was satisfied that the analysis of options using financial and non–financial criteria was appropriate and demonstrated the prudence of the proposed expenditures.[284]

PB noted in respect of the efficiency of the expenditures proposed, PB noted that all proposed project costs included contingency costs which accounted for elements of the scope of work that had not been well defined and effectively represented a risk allowance for unforeseen issues. PB considered that the inclusion of such costs effectively transferred risks to Energex's customers, which they are not in a position to manage. PB therefore did not consider it prudent or efficient to include the contingency amounts in the capex allowance. PB considered that any inclusion of a contingency amount would need to be considered in the context of the quality and robustness of the estimating process used, how well the business updates the inputs to that process, and how well it describes and explains the nature of latent or other risks it is trying to manage. PB recommended the removal of contingency costs from all

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[281] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 14.
[282] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 15.
[283] PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 14–15.
[284] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 15.

major property projects based on the limited information presented by Energex in its business cases.[285]

PB also reviewed the proposed timing for delivery of the major projects and noted that Energex's proposed timelines for delivery accorded with the project timing milestones identified in independent property industry advice from RCP, with the exception of a depot site. PB noted that the project was proposed by Energex for implementation in 2010–11, but proposed for completion by RCP in June 2012. In the absence of any supporting information to advance the timing of this project, PB recommended that the proposed capex for the project be deferred to 2011–12 as advised by RCP.[286]

Based on its review of the additional information provided by Energex in its revised regulatory proposal, PB concluded that Energex's revised proposed land and buildings capex was prudent and efficient, with the exception of the contingency costs included in the estimates for all major property projects and the timing of the depot project.[287]

PB recommended that Energex's revised capex forecast for major property projects be amended to reflect the removal of contingency costs of $30 million ($2009–10) and the deferral of capex for the depot project from 2010–11 to 2011–12.[288] PB's recommended capex for non–system land and buildings is outlined in table 7.11.

Table 7.11: PB's revised non–system land and buildings capex ($2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex revised proposal[a]	143.1	67.7	44.4	18.5	24.7	298.4
PB adjustment	–36.2	8.7	–2.1	–	–	–29.6
Recommended total	106.9	76.3	42.3	18.5	24.7	268.7

Source: PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 17.
Note: Totals may not add due to rounding.
(a) Before the application of Energex's revised cost escalators.

AER considerations

The AER reviewed Energex's revised regulatory proposal and supporting documentation provided in relation to the revised non–system capex proposal for major property projects and sought advice from PB on the prudence and efficiency of the expenditures proposed.

In the draft decision, the AER noted that Energex had not provided business case documentation or other supporting documentation to justify the major property project expenditures proposed.[289] The AER notes that Energex sought to address the AER's

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285 PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 15–16.
286 PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 16–17.
287 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 17.
288 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 17.
289 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 492.

concerns through the provision of its latest corporate property strategic plan and business case documentation supporting each of the proposed projects.[290]

Energex's revised regulatory proposal and supporting documentation provided new information relevant to the assessment of the prudence and efficiency of the proposed major building projects in relation to the capex approval process, risk assessment analysis, business cases and alternative project options, and project delivery and timing.[291]

The AER has, in relation to Energex's approval processes for the major property projects, considered PB's view that the approval processes employed for the major property projects align with those employed by Energex for system capex, which PB previously found to be appropriate.[292] The AER agrees with the analysis and findings of PB in this regard. The AER also notes that the business cases for major property projects have been endorsed by Energex's Investment Review Committee.[293] For these reasons, the AER considers that Energex's revised regulatory proposal demonstrates a prudent approach to capital governance in relation to the property plan.

The AER notes that PB found that that the methodology employed in the RCP and AECOM risk assessments was robust and appropriate for the purposes of identifying and prioritising the mitigation of risk relating to Energex's existing property portfolio.[294] The AER has considered the material provided by PB and agrees with it. Accordingly, the AER considers that the additional risk assessment information provided by Energex as part of its revised regulatory proposal addresses the concerns identified by the AER in its draft decision that Energex's risk assessment was not rigorous and did not demonstrate the timing of expenditure proposed by Energex.[295]

The AER notes that PB reviewed the business cases and alternative project options analysis provided in relation to the proposed six major property projects, and conducted a detailed review of the [redacted] facility (the largest of the proposed property projects). The AER notes that, in relation to all projects proposed, PB was satisfied that the analysis of options using financial and non–financial criteria was appropriate and demonstrated the prudence of the proposed expenditures.[296] The AER has considered the review conducted by PB and agrees with the views expressed by PB in this regard.

The AER notes that all proposed projects include contingency costs which, in PB's view, account for elements of the scope of work that have not been well defined by Energex and effectively represent a risk allowance for unforeseen issues.[297] The AER has considered, and agrees with, the views expressed by PB that the inclusion of such contingency costs, which have not been well justified in terms of the nature of the

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290 Energex, *Revised regulatory proposal*, January 2010, p. 16.
291 PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 12–13.
292 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 13.
293 Energex, *Revised regulatory proposal*, January 2010, p. 16.
294 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 14.
295 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 492.
296 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 15.
297 PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 15–16.

risks they are intended to manage in the context of the estimating process for the project scope, unreasonably transfers risks associated with these projects to Energex's customers. The AER considers that Energex's customers are not in a position to manage such risks.

The AER notes PB's recommendation that contingency costs should be removed from all major property projects based on the limited information presented by Energex in its business cases.[298] On the basis of PB's advice and its own review, the AER considers that the proposed contingency costs have not been demonstrated to be efficient, and should be removed from the forecast capex allowance for the major property projects.

In relation to the timing for delivery of the major property projects, the AER notes that Energex's proposed timelines for delivery accord with advice from RCP with the exception of the depot site. The project was proposed by Energex for implementation in 2010–11, but proposed for completion by RCP in June 2012.[299] In the absence of any supporting information to advance the timing of this project, the AER considers that the proposed capex for the project should be deferred to 2011–12.

Based on Energex's revised regulatory proposal, additional supporting information from Energex, the advice of PB and its own analysis, the AER is satisfied that Energex has largely addressed the concerns set out in the draft decision regarding the prudence and efficiency of proposed capex for major property projects. The AER therefore considers that Energex's revised proposed land and buildings capex has been demonstrated to be both prudent and efficient, with the exception of the contingency costs included in the estimates for all major property projects and the timing of the depot project.[300]

AER conclusion

The AER requested Energex model the impact of the AER's decision on non–system capex. Energex advised that the adjustment to forecast non–system capex is a reduction of $32 million ($2009–10).[301]

For the reasons discussed and as a result of the AER's consideration of Energex' revised regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's forecast non–system capex for major property projects reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Energex' proposed non–system capex by $32 million ($2009–10) 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.

298 PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 15–16.
299 PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 16–17.
300 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 17.
301 Energex, response to modelling response, 9 April 2010, confidential.

7.4.4.4 Non–system capex—motor vehicles, tools and equipment

AER draft decision

The AER concluded that Energex's proposed non–system capex for motor vehicles and tools and equipment represented the efficient costs of a prudent operator in Energex's circumstances. The AER accepted Energex's forecast non–system capex for motor vehicles and tools and equipment as proposed.[302]

Revised regulatory proposal

Energex proposed revised forecasts for non–system capex in the motor vehicles and tools and equipment categories to correct an error in the application of materials escalations in the preparation of its regulatory proposal.[303]

Energex advised that an error occurred in converting materials forecasts for motor vehicles and tools and equipment non-system capex from nominal to real values, which resulted in understated material forecasts in these categories.[304] The correction of this error in the revised regulatory proposal resulted in an increase in motor vehicles capex of $8 million, and in tools and equipment capex of $2 million.[305]

Consultant review

PB reviewed Energex's revised regulatory proposal, including the detailed calculations indicating the effect of the error identified by Energex on the forecast motor vehicles and tools and equipment capex. PB noted that the cause of the error was the application of a 5.5 per cent materials escalator rather than 4.5 per cent during the restatement of values for the next regulatory control period from nominal terms to real $2009–10.[306]

Based on its review of the detailed spreadsheet model provided by Energex, PB was satisfied that the error as described caused the understatement in total forecast capex for motor vehicles and tools and equipment of $10 million ($2009–10). PB recommended the AER accept the revised forecast expenditure for these categories.[307]

AER considerations

The AER notes that Energex proposed revised forecasts for non–system capex in the motor vehicles and tools and equipment categories due to an error in the application of materials escalations in the preparation of its original regulatory proposal.[308] The AER sought advice from PB on the prudence and efficiency of the revised proposed expenditures, and notes PB's view that the error as described by Energex caused the relevant understatement in total forecast capex of $10 million ($2009–10).[309]

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[302] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 491.
[303] Energex, *Revised regulatory proposal*, January 2010, p. 17.
[304] Energex, *Email response to AER.EGX.RP.1.5*, 5 February 2010, confidential.
[305] Energex, *Revised regulatory proposal*, January 2010, p. 17.
[306] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 18.
[307] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 18.
[308] Energex, *Revised regulatory proposal*, January 2010, p. 17.
[309] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 18.

On the basis of its own review and the advice from PB, the AER has concluded that Energex's revised regulatory proposal appropriately accounts for the error made in the preparation of Energex's original forecast of non–system capex in the motor vehicles and tools and equipment categories.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Energex's revised regulatory proposal and PB's report, the AER is satisfied that Energex's forecast non–system capex for motor vehicles and tools and equipment reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

7.4.4.5 ICT services (overheads)

AER draft decision

The AER sought advice from PB on the prudence and efficiency of ICT costs to be capitalised by SPARQ and reflected as service charges (overheads) by the Qld DNSPs.

The AER concluded that with the exception of the Distribution Management System (DMS) stage 2 project, Energex's proposed ICT overheads costs for new capability projects was not supported by analysis which demonstrated the prudence and efficiency of proposed expenditures. The AER reduced Energex's proposed capex by $7 million and proposed opex by $2 million ($2009–10) to reflect the reduction in proposed ICT overheads across both the capex and opex forecasts.[310]

Revised regulatory proposal

Energex acknowledged the comments made by PB on the documentation provided by Energex for the planned new capability ICT projects.[311] Energex did not accept the reductions made by the AER in relation to ICT related overheads and provided business case documentation in support of its original proposal.[312]

Consultant review

PB conducted a detailed review of Energex's revised ICT expenditure, which included ten projects aimed at providing new ICT capability.

PB noted that Energex provided business cases for only seven of these projects, which accounted for approximately $8.4m (or 29.2 per cent) of total new ICT capability expenditure proposed by Energex. PB also noted that no new information had been provided for the other three projects, which together accounted for $4.9m (or 17.1 per cent) of total new ICT capability expenditure.[313]

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[310] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 121, 165.
[311] Energex, *Revised regulatory proposal*, January 2010, p. 27.
[312] Energex, *Revised regulatory proposal*, January 2010, p. 27.
[313] PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 7–8.

To supplement its review, PB requested supporting information for the DINIS/PSSU/DMS project[314] on the basis that it was the most costly of the new capability projects. Additional information provided by Energex included the change management plan, risk management plan, and NPV model for this project.[315]

PB confirmed that the NPV of $9.7m in the business case for the DINIS/PSSU/DMS project reconciled with the cash flow analysis for this project that was included in the NPV model provided by Energex.[316]

PB noted Energex had considered alternatives to the proposed project, including a limited version of the project and a 'do nothing' option, and that both were considered undesirable due to the increased level of effort required to maintain separate information repositories and errors associated with future growth estimation and network capacity calculations.[317]

PB considered that benefits associated with the project would include better planning and design and effective network modelling to ensure benefits of the DMS.[318]

PB also undertook a high level review of the remaining business cases submitted for review and noted that all of them produced a positive NPV under a base case cost scenario with payback periods ranging between 2 years and 5 years. PB considered that this suggested that the new capability projects were largely self-funding. PB also noted that for all of the other business cases, alternative options including 'do nothing' were identified.[319]

PB was not satisfied with those new capability projects where no new information had been provided to justify the expenditure.[320]

Based on the findings outlined above, PB recommended that the new capability ICT projects for which Energex had provided new business cases be approved and that those for which no new information was provided be rejected.[321]

PB noted that the recommended expenditure will be capitalised within SPARQ and passed through to Energex as a service charge. To calculate the reduction in the service charge associated with the SPARQ capex, PB used the 2008–09 SPARQ service charge as the base year costs and assumed the increase in the ICT overhead during the next regulatory control period is predominantly driven by the 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. The results are presented in table 7.12.

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314 These acronyms stand for Distribution Network Information System, Power System Simulation for Utilities and Distribution Management System.
315 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 9.
316 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 9.
317 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 9.
318 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 9.
319 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 9.
320 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 10.
321 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 10.

Table 7.12: PB recommended reduction in Energex's ICT indirect costs expenditure – SPARQ ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ICT indirect costs	78.8	91.3	97.7	95.4	93.9	457.0
ICT baseline costs ($2009–10)	67.0	67.0	67.0	67.0	67.0	335.0
Increase in ICT ($m)	11.8	24.3	30.7	28.4	26.9	122.0
% reduction in SPARQ capex recommended by PB	–2.8	–0.5	–0.6	–3.5	–7.1	–2.7
Proportional reduction in ICT indirect costs	–0.3	–0.1	–0.2	–1.0	–1.9	–3.3
Reduction in capex indirect costs	–0.23	–0.08	–0.16	–0.77	–1.46	–2.54
Reduction in opex indirect costs	–0.07	–0.02	–0.4	–0.23	–0.44	–0.76
PB recommendation	78.5	91.2	97.5	94.4	92.0	453.7

Source: PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 11.

AER considerations

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 reviewed the material provided by Energex to support its revised regulatory proposal in relation to ICT overhead expenditure. The AER notes that Energex provided new business case documentation to support seven new capability ICT projects not approved in the draft decision.

The AER notes that all of the new business cases provided by Energex include consideration of project options, including, for example, limited versions of proposed projects and a 'do nothing' option.

The AER considers that PB's more detailed review and request for additional information for the DINIS/PSSU/DMS project was appropriate given that it was the most costly of the new capability projects. The AER reviewed the documentation provided by Energex for this project and confirms PB's finding that the project is NPV positive. The AER also notes PB's finding that the remaining business cases submitted for review are all NPV positive, suggesting that the new capability projects will be self-funding.

Given that Energex provided sound business cases for seven of the ten proposed new capability ICT projects, the AER accepts PB's recommendation to approve the increase in Energex's ICT service charges that are associated with expenditure for these projects.

The AER notes that Energex did not provide any new information for three of the new capability ICT projects, including performance management, performance management upgrade and operations report development. On this basis, the AER does not consider that higher ICT service charges associated with these projects are justified.

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 $2 million ($2009–10).[322]

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Energex's revised 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 $2 million ($2009–10) 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.

7.4.5 Ergon Energy

7.4.5.1 Growth capex and demand forecasts

AER draft decision

The AER rejected Ergon Energy's proposed total growth capex of $3686 million, and made adjustments to both the customer initiated capital works (CICW) and corporation initiated augmentation (CIA) components of growth capex. The total reduction to proposed growth capex was $844 million.[323]

CIA capex

The draft decision noted advice from PB that it was unable to establish a clear relationship between the relevant planning documentation and the CIA capex proposal, and was therefore unable to conclude that the CIA capex proposal was efficient.[324]

The capex allowance set out in the draft decision was based on advice from MMA that Ergon Energy's peak demand forecasts were likely to be overstated to the extent of one to two years peak demand growth. The AER was therefore not satisfied that Ergon Energy's forecast demand related growth capex reasonably reflected a realistic expectation of the demand forecast required to achieve the capex objectives.[325]

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[322] Energex, response to modelling response, 9 April 2010, confidential.
[323] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 130.
[324] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 526.
[325] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 528.

The AER considered it appropriate that Ergon Energy's proposed demand related growth capex be reduced to account for Ergon Energy's overestimation of forecast maximum demand in the next regulatory control period.[326]

PB recommended that Ergon Energy's proposed demand related growth capex be reduced by the equivalent of 18 months of demand related expenditure. The AER considered such an approach to be appropriate for estimating a substitute forecast of CIA capex which reasonably reflects a realistic expectation of forecast demand.[327]

The AER concluded that Ergon Energy's growth related CIA capex forecast should be reduced by $526 million ($2009–10).[328]

CICW capex

The AER concluded that the robustness of Ergon Energy's forecast of CICW capex was not supported by Ergon Energy's forecasting methodology, which relied upon the assumed applicability of various growth forecasts which the AER did not consider to be appropriate.

The AER reduced Ergon Energy's forecast CICW capex on the basis of an alternative forecasting methodology proposed by PB which relied upon a business as usual approach related to historical connection costs and the forecast customer growth rate.

The draft decision reduced Ergon Energy's forecast CICW capex by $318 million ($2009–10).[329]

Revised regulatory proposal

CIA capex

Ergon Energy resubmitted its original CIA capex proposal, adjusted for changes to cost escalations and the reallocation of overheads.[330]

Ergon Energy undertook a detailed review of its proposed CIA capex forecast with specific regard to the concerns raised by the AER in its draft decision. Ergon Energy concluded that the forecast proposed in its June 2009 regulatory proposal most reasonably reflected the costs of meeting its regulatory obligations.[331]

Ergon Energy considered that the AER's reduction to its proposed CIA capex:[332]

- incorrectly assumed Ergon Energy's planning documentation cannot be aligned with its forecast capital expenditure

326 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 528.
327 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 528–529.
328 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 529.
329 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 529.
330 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 99.
331 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 104.
332 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 104.

- relied upon MMA's top–down global demand forecast, which was flawed in its approach, utilised incorrect data and is inherently less accurate than the combined top–down and bottom–up approach employed by Ergon Energy

- relied on sensitivity analysis which significantly overstated the proportion of Ergon Energy's CIA capex which is sensitive to a deferral of forecast demand

- is inconsistent with previous regulatory determinations in assuming that there is a linear and proportional relationship between growth related capex and global maximum demand.

Ergon Energy submitted a revised proposed forecast for CIA capex of $2076 million ($2009–10), an increase of approximately $85 million ($2009–10) from its original regulatory proposal.[333]

CICW capex

Ergon Energy did not accept the AER's reduction to proposed CICW capex. It stated the AER's substitute forecast was not realistic and exposed Ergon Energy to considerable risk of unfunded connection requirements.[334]

Ergon Energy provided additional information in support of the assumptions underpinning its CICW capex forecast, including the applicability of dwelling stock growth forecasts as a driver of CICW capex.[335]

Ergon Energy submitted a revised forecast for CICW capex of $1847 million ($2009–10), an increase of approximately $152 million from its original regulatory proposal. The change in Ergon Energy's proposed CICW capex is partly explained by changes to cost escalations and re reallocation of overheads in addition to changes to Ergon Energy's forecasting methodology.[336]

Consultant review

CIA capex

PB reviewed Ergon Energy's revised CIA capex proposal and additional supporting material to consider whether Ergon Energy had addressed its concerns that:[337]

- limited and incomplete business case documentation did not demonstrate the efficiency of the proposed capex

- a clear relationship between the capex forecast and Ergon Energy's planning documentation could not be established.

Availability of business case documentation

PB noted Ergon Energy's argument that 'the consideration of options alone does not ensure efficiency, and any finding of relative efficiency … should only be considered

333 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 106.
334 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 111.
335 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 109–110.
336 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 99, 110.
337 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 4.

if there is direct evidence that the capital expenditure is not efficient.' PB disagreed with this principle, and suggested that prudent expenditure requires appropriate demonstration that the proposed expenditure is reasonably likely to be the most efficient option to address the identified need, given the set of all reasonable or practical options available.[338]

PB agreed with Ergon Energy that it is difficult for a DNSP to have business case documentation available for all projects over a period up to seven years in advance. However, PB noted that it was not uncommon for high value projects, particularly those proposed early in the regulatory control period, to be supported by business cases or other supporting material. In relation to Ergon Energy, PB considered that with consideration of the options for many projects not always documented, or not documented to a standard that enables external evaluation, it was unable to conclude that the proposed CIA capex was efficient through examination of the proposal documentation.[339]

Reconciliation of planning documentation to capex forecast
PB noted that Ergon Energy had engaged Huegin to undertake a reconciliation of the CIA capex forecast and the 2007 planning documentation on which the capex forecast was based. PB attempted to reconcile the capex projects identified by Huegin with the 2007 sub-transmission network augmentation plan (SNAP) and found a number of abnormalities, including:[340]

- in three cases, projects with commissioning dates well outside the next regulatory control period were included in the Huegin reconciliation

- in two cases, capex costs were included in the Huegin reconciliation for projects not included in the 2007 SNAP.

PB further noted that in the majority of cases it was unable to identify the basis for the project cost 'units' included in the Huegin reconciliation, and that comments for a number of projects in the planning documentation highlighted additional concerns regarding the scope, timing, fundamental need and consideration of options for these projects. On the basis of its review, PB concluded that it remains of the view that the capex forecast does not reasonably reconcile with the 2007 SNAP provided with Ergon Energy's regulatory proposal.[341]

Reconciliation of 2007 and 2009 planning documentation
In the course of PB's review of the 2007 planning documentation underpinning the capex forecast, Ergon Energy provided a copy of its 2009 planning documentation. This was not available at the time of Ergon Energy submitting its regulatory proposal. PB noted that the 2007 and 2009 planning documents had been prepared on the basis of substantially the same network security criteria and demand forecasts. PB therefore undertook a reconciliation of the 2007 and 2009 SNAP documentation in relation to the projects previously reconciled by Huegin in the expectation that there would be a

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[338] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 9.
[339] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 9.
[340] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 10–11.
[341] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 11–12.

high degree of correlation between the documents given the greater diversification of load at the sub–transmission level typically enables more accurate medium term forecasting of constraints.[342]

PB found that the majority of projects included in the 2007 documentation were also included in the 2009 documentation, however, the timing of many projects had been deferred significantly. PB noted that:[343]

- 41 of the 86 projects previously reconciled by Huegin had been deferred beyond the next regulatory control period under the 2009 documentation
- 11 of the 86 projects were now scheduled between 2020 and 2030
- 8 of the 86 projects were now scheduled between 2030 and 2040
- in comparison to the 41 deferred projects, only five projects had been brought forward from later commissioning dates into the next regulatory control period
- only 6 per cent of projects in the Huegin sample were reconciled in both value (plus or minus 10 per cent) and timing (within the next regulatory control period) between the 2007 and 2009 versions of the planning documents.

PB noted that Ergon Energy had undertaken a reconciliation of the 266 projects included in the 2009 SNAP for the next regulatory control period with the projects identified in the 2007 SNAP. PB noted Ergon Energy's findings that:[344]

- 95 projects (36 per cent) in the 2009 SNAP also appeared in the 2007 SNAP
- 95 projects (36 per cent) that were expected in 2007 to be completed in the current regulatory control period had been deferred to the next regulatory control period
- 6 projects (2 per cent) scheduled for dates beyond June 2015 had been brought forward into the next regulatory control period
- 70 new projects (26 per cent) have been identified for the next regulatory control period since preparation of the 2007 SNAP due to unforeseen changes in local customer or demand forecasts or as alternative solutions to existing problems.

PB accepted Ergon Energy's analysis and noted that the high degree of deferral, small number of projects brought forward, and low degree of alignment of projects falling within the next regulatory control period was consistent with PB's findings.[345]

Given that the 2007 and 2009 planning documentation had been prepared by Ergon Energy on the basis of substantially the same security criteria and demand forecast, PB concluded that the large number of deferrals identified resulted from the insufficient consideration of project timing or alternative options in the planning stage

[342] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 12–13.
[343] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 13.
[344] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 14.
[345] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 14.

of sub–transmission projects. In particular, PB considered that the lack of preliminary business cases or similar documentation to inform medium term planning decisions appeared to have had a material influence on the variability of the expected composition of the capital program over the next regulatory control period, with only a 36 per cent correlation between the capital programs identified in 2007 and 2009. PB considered this view to be further supported by the number of new projects included in the 2009 planning documents as a result of alternative solutions to existing problems. PB considered this to have been driven by changes to previously included projects following a more detailed consideration of alternative options.[346]

PB concluded that the 2007 SNAP did not reflect the likely timing of projects based on the latest available information and therefore did not represent a reasonable basis for the capex forecast.[347] Given the demonstrated volatility of Ergon Energy's capital planning and history of deferring large proportions of capex, PB considered that there were still a significant number of projects included in the 2009 planning documentation that were likely to be deferred following a more complete investigation of the fundamental need, timing, alternative options and scope. Under Ergon Energy's existing processes, this investigation would not occur until closer to the forecast commissioning date for each project.[348]

On the basis of its review, PB considered that neither the 2007 nor 2009 SNAP could be considered to provide an efficient basis for the capital program. PB was therefore unable to conclude that Ergon Energy's proposed sub–transmission CIA capex represented prudent and efficient expenditure.[349]

Adjustment to sub–transmission CIA capex

In considering the extent of the adjustment required to ensure the prudence and efficiency of allowed expenditure, PB noted that 36.4 per cent of the $617 million in sub–transmission CIA capex reconciled by Huegin and examined by PB was no longer supported by the most recent planning information provided by Ergon Energy. Given the interrelationship between the categories of sub–transmission capex considered by PB and those not considered, PB was of the view that similar issues would be expected across the remainder of the proposed sub–transmission CIA capex.[350]

Therefore, in relation to projects deferred and brought forward between the next regulatory control period and subsequent regulatory control periods, PB recommended that a 36.4 per cent ($353 million) reduction be applied across the total of Ergon Energy's proposed sub-transmission CIA capex.[351]

In relation to capex that might be deferred from the current regulatory control period to the next regulatory period, PB noted that Ergon Energy had identified 93 deferred projects costed in the 2007 planning estimates at $165 million. Given the identified ratio of actual proposed capex costs to the 2007 planning estimate costs of

346 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 15–16.
347 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 13.
348 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 17.
349 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 17.
350 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 18.
351 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 19.

72 per cent, PB recommended an offsetting increase of $119 million to account for projects moving into the next regulatory control period from the current regulatory control period.[352]

Accounting for the $353 million reduction for deferrals out of the next regulatory control period, offset by the $119 million increase for deferrals into the next regulatory control period, PB recommended a total reduction to sub–transmission CIA capex of $234 million ($2009–10) as shown in table 7.13.

Table 7.13: PB recommended Ergon Energy sub–transmission CIA capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Sub–transmission CIA capex	130.9	164.9	194.0	226.0	254.1	969.9
Adjustment for deferrals beyond next regulatory control period (36.4%)	–46.4	–60.4	–71.8	–82.9	–91.1	–352.7
Adjustment for deferrals into next regulatory control period	15.7	20.4	24.3	28.0	30.8	119.1
Total adjustment	–30.7	–40.0	–47.6	–54.9	–60.3	–233.5

Source: PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p.20.
Note: Totals may not add due to rounding.

CIA capex demand forecast sensitivity

PB reviewed Ergon Energy's arguments rejecting the adjustment made in the draft decision as a result of Ergon Energy's capex proposal reflecting an unrealistic expectation of demand.

PB noted Ergon Energy's argument that the draft decision relied on a sensitivity analysis which overstated the demand sensitive proportion of the CIA capex proposed. PB noted the advice from Huegin that the proportion of CIA capex that is sensitive to the demand forecast is between 55.4 per cent and 86.3 per cent.[353]

PB considered that it was reasonable to expect that Ergon Energy should be able to verify the portion of capex that is sensitive to the demand forecast. However, as PB was unable to conclude specifically what the proportion should be on the basis of the information provided by Ergon Energy, PB assumed the average value of the range identified by Huegin (70.9 per cent) to be the proportion of total CIA capex that is sensitive to variation in the demand forecast.[354]

[352] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 19.
[353] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 6.
[354] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 6.

PB considered Ergon Energy's criticisms of the basis for applying a top–down adjustment to CIA capex, and noted that:[355]

- the adjustment method was a high level approach, not intended to model the variation in demand growth at a feeder level
- while the most accurate and robust method to determine the required CIA capex is through a bottom–up process which demonstrates an observable relationship between the identified need, the selected option and the capex proposal, PB has been unable to reasonably establish this relationship based on its review of Ergon Energy's regulatory proposal
- there is no reason inherent in the method itself that would cause a systematic overstatement or understatement of the results.

PB noted the updated advice from MMA that Ergon Energy's demand forecast underpinning its CIA capex proposal was, on average, overstated by approximately 157 MW per year. Given the average annual growth in Ergon Energy's demand forecast of approximately 94 MW, PB considered the difference between the MMA and Ergon Energy demand forecasts remained essentially similar to the 18 month deferral applied by PB in its previous review.[356]

PB therefore recalculated the 18 month (30 per cent) demand forecast adjustment on the basis of an assumed sensitivity of CIA capex to the demand forecast of 70.9 per cent. PB applied the demand forecast adjustment to the CIA capex forecast after accounting for the adjustment arising from reconciliation issues in Ergon Energy's planning documentation, resulting in a recommended reduction to CIA capex as a result of the demand forecast of $392 million ($2009–10).[357]

Conclusion

PB concluded that Ergon Energy's total proposed CIA capex should be reduced by $626 million ($2009–10). Due to the steep annual growth in CIA capex proposed by Ergon Energy, PB considered that a direct scaling of the proposed capex did not provide a realistic distribution of expenditure, with expenditure weighted towards the latter years of the regulatory control period. PB therefore spread the adjusted capex forecast across the years of the next regulatory control period, such that the adjusted CIA capex forecast grows in line with historic trend growth of $20.5m per year. PB noted that, after accounting for its recommended adjustment, the CIA capex allowance of $1451 million ($2009–10) represented a real increase of 33 per cent over Ergon Energy's CIA capex in the current regulatory control period.[358] PB's recommended adjustment to Ergon Energy's CIA capex is shown in table 7.14.

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355 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 7–8.
356 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 8.
357 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 20–21.
358 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 20–21.

Table 7.14: PB recommended CIA capex for Ergon Energy ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy revised proposal	273.3	355.8	423.0	487.9	536.3	2076.3
Adjustment to sub–transmission CIA capex	–30.7	–40.0	–47.6	–54.9	–60.3	–233.5
Subtotal CIA capex	242.6	315.8	375.4	433.0	476.0	1842.8
Proportion of CIA capex related to demand forecast (70.9%)	172.0	223.9	266.2	307.0	337.5	1306.5
Smoothed adjustment for 18 month deferral (30%)	6.6	–46.1	–85.3	–122.3	–144.8	–392.0
PB recommended total	249.1	269.6	290.2	310.7	331.2	1450.8

Source: PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p.21.
Note: Totals may not add due to rounding.

CICW capex

PB reviewed Ergon Energy's revised CICW capex proposal and the supporting material provided, including the report from Ergon Energy's consultant Huegin examining the reasonableness of Ergon Energy's original CICW capex proposal.

PB noted that Ergon Energy's revised regulatory proposal used dwelling stock growth as the forecast driver for all CICW expenditure, and that its revised capex forecasts were calculated on that basis.[359]

PB reviewed the analysis undertaken by Huegin to support the use of dwelling stock growth as a driver for forecasts of small commercial and industrial connection capex. PB noted that Huegin's identification of non–residential construction costs as a driver for small commercial and industrial connection capex did not demonstrate that dwelling stock growth is a good driver of these connections. PB considered that Huegin's use of non–residential construction data as a test of Ergon Energy's forecast based on dwelling stock growth had not demonstrated that the forecasts moved together or that the apparent correlation would continue into the future. Accordingly, PB did not consider that the causality between dwelling stock growth forecasts and small commercial and industrial connections had been demonstrated.[360]

PB reviewed Ergon Energy's revised forecasting methodology for large commercial and industrial connections, and similarly considered that Ergon Energy had not adequately demonstrated the causality between dwelling stock growth and growth in large connections. Specifically, PB considered that the correlation analysis presented by Ergon Energy, which relied on domestic and rural connections data as a proxy for dwelling stock growth due to the unavailability of historical data, merely

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[359] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 23.
[360] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 24–25.

demonstrated that the total cost of connections increased with the number of connections. PB considered that causality between the driver and the forecast had not been adequately demonstrated, and was unable to conclude that the revised CICW capex forecast was prudent and efficient.[361]

PB noted and accepted some of the criticisms of its alternative CICW forecasting model outlined in Ergon Energy's revised regulatory proposal and Huegin's report. PB accepted that it had used incorrect historical connections data as a modelling input, which had the effect of understating its forecast for CICW capex in the next regulatory control period. However, regarding the model itself, PB did not consider that any new and substantive information had been provided as part of Ergon Energy's revised regulatory proposal to suggest that a more reasonable or detailed forecasting approach was achievable.[362]

PB therefore maintained its advice that its model, based on average historical numbers and costs of customer connections escalated for anticipated growth in customer numbers, provided for a prudent and efficient level of CICW capex which ensured future customer connection activities at levels consistent with Ergon Energy's recent historical experience. PB used the corrected historical data inputs advised by Ergon Energy to re–run its forecasting model. Based on this approach, PB recommended a reduction of $402 million ($2009–10) to Ergon Energy's revised proposed CICW capex, as shown in table 7.15.[363]

Table 7.15: PB recommended Ergon Energy CICW capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Revised proposal	363.7	394.7	341.8	357.3	389.0	1846.5
PB adjustment	–73.9	–103.2	–56.5	–68.4	–100.4	–402.3
PB recommended total	289.8	291.6	285.3	288.9	288.6	1444.2

Source: PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 30.
Note: Totals may not add due to rounding.

AER considerations

CIA capex

The AER reviewed Ergon Energy's revised CIA capex proposal and sought advice from PB as to the prudence and efficiency of the proposed expenditure, and the methodology for, and amount of any, adjustment required as a result of MMA's review of Ergon Energy's revised maximum demand forecasts.

Sub–transmission CIA capex

The AER notes that PB raised concerns with both the reconciliation of the 2007 sub–transmission planning documentation to the capex proposed, and the

361 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 26–27.
362 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 28–30.
363 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 30.

reconciliation of the 2007 planning documentation in the context of the latest (2009) planning information provided by Ergon Energy.

The AER notes that PB found a number of abnormalities in reconciling the CIA capex forecast to the 2007 planning documentation from which the capex forecast was derived, such as the inclusion of costs for projects not referenced in the planning documentation and for projects with commissioning dates well outside the next regulatory control period. For example, the AER notes that:[364]

- full costs for the Blackwater 22kV regulator augmentation were included in the Huegin reconciliation of capex costs despite the commissioning date for the project being more than two years beyond the end of the next regulatory control period
- projects for a second 110kV line for the rebuilt Toowoomba central substation and second 220/66kV transformer for the Chumvale substation are included in Ergon Energy's capex forecast but are not included in the 2007 planning documentation.

The AER, having considered the advice of PB and the information available, is of the view that the capex forecast has not been shown to fully reconcile with the relevant planning documentation.

The AER notes that while Ergon Energy's capex forecast is based on its 2007 planning documentation Ergon Energy, following the submission of its revised regulatory proposal, provided its 2009 planning documentation. Given the 2009 planning documentation had been prepared on the basis of substantially the same network security criteria and demand forecasts as the 2007 documentation, PB undertook a reconciliation of the 2007 and 2009 sub–transmission planning documentation in the expectation that there would be a high degree of correlation between the documents. The AER notes that Ergon Energy also undertook a reconciliation of the projects proposed for the next regulatory control period in both the 2007 and 2009 SNAPs.[365]

The AER notes that the analyses presented by PB and Ergon Energy comparing the 2007 and 2009 SNAPs both demonstrate: a high degree of project deferral; only a small number of projects being brought forward; and a low degree of alignment of projects falling within the next regulatory control period. For example, the AER notes that:[366]

- 64 per cent of the projects expected in 2007 to form the basis of Ergon Energy's sub–transmission capex program for 2010–15 are no longer expected to be undertaken in the next regulatory control period
- 48 per cent of the projects reconciled by Huegin in the 2007 SNAP have been deferred beyond the next regulatory control period under the 2009 SNAP

[364] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 10–11.
[365] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 12–14.
[366] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 13–14.

- PB identified 19 projects proposed by Ergon Energy for the next regulatory control period which are now expected to be commissioned after 2020

- 95 projects that were expected in 2007 to be completed within the remaining years of the current regulatory control period are now expected to be undertaken in the next regulatory control period

- 6 per cent of projects reviewed by PB were reconciled in both value (plus or minus 10 per cent) and timing (within the next regulatory control period) between the 2007 and 2009 versions of the planning documents.

The AER considers the 2007 SNAP underpinning Ergon Energy's sub–transmission capex proposal does not reflect the likely timing of sub–transmission capex projects based on the latest available information, and therefore does not represent a reasonable basis for the capex forecast. The AER notes PB's view that this is due to insufficient consideration of project timing or alternative options in the planning stage of sub–transmission projects, reflected in the lack of preliminary business cases, or similar documentation, to inform medium term planning decisions.[367] The AER agrees that Ergon Energy's planning approach appears to have resulted in significant volatility in the expected composition of the forecast capital program between 2007 and 2009, given no change in the underlying network security criteria and only a 'marginal decrease'[368] in the spatial demand forecast assumptions.

Regarding the 2009 SNAP, the AER notes PB's view that given the demonstrated volatility of Ergon Energy's capital planning and history of deferring large proportions of capex, there are still a significant number of projects included in the 2009 planning documentation that are likely to be deferred following a more complete investigation of the fundamental need, timing, alternative options and scope.[369] The AER agrees that there is no evidence to suggest that the 2009 SNAP will prove to be substantially more accurate than the 2007 SNAP given Ergon Energy's planning approach. For example, the AER notes PB's advice that the number of 'new' projects identified by Ergon Energy in the 2009 SNAPs is likely to be overstated as these typically in fact relate to a reconsideration of existing projects and issues rather than unexpected emerging network constraints.

The AER notes that PB considered that neither the 2007 nor 2009 SNAP provided an efficient basis for the sub–transmission capital program. PB was therefore unable to conclude that Ergon Energy's proposed sub–transmission CIA capex represented prudent and efficient expenditure.[370]

The AER considers there is strong evidence to suggest Ergon Energy's sub-transmission CIA capex proposal, based on the 2007 planning documentation, is not reflective of the likely scope of the CIA capex program in the next regulatory control period. The AER is therefore unable to conclude that the proposed capex has been demonstrated to reflect the costs that a prudent operator in the circumstances of

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[367] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 13–14.
[368] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 106.
[369] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 17.
[370] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 17.

Ergon Energy would require in the next regulatory control period to meet the capex objectives. Under clause 6.5.7 of the NER, the AER cannot accept Ergon Energy's proposed sub–transmission CIA capex.

The AER notes that PB recommended an adjustment to Ergon Energy's proposed sub–transmission CIA capex to reflect a prudent and efficient level of expenditure over the next regulatory control period.[371]

In relation to projects deferred and brought forward between the next regulatory control period and subsequent regulatory control periods, the AER notes that PB recommended that a 36.4 per cent ($353 million) reduction be applied across the total of Ergon Energy's proposed sub-transmission CIA capex based on the known proportion of capex deferred by the latest planning documentation.[372]

In relation to capex deferred into the next regulatory control period from the current regulatory control period, the AER notes PB's recommendation that an offsetting increase of $119 million be allowed to account for 93 projects moving into the next regulatory control period from the current regulatory control period.[373] Accounting for the $353 million reduction for deferrals out of the next regulatory control period, offset by the $119 million increase for deferrals into the next regulatory control period, the AER notes PB recommended a total reduction to sub–transmission CIA capex of $234 million ($2009–10).[374]

The AER considers that PB's recommendations represent a reasonable approach to estimating the adjustment required to provide an appropriate forecast of sub-transmission CIA capex as it accounts for the project deferrals both into, and out of, the next regulatory control period.

CIA capex and the demand forecast

The AER sought updated advice from MMA regarding the reasonableness of Ergon Energy's maximum demand forecasts underpinning its CIA capex proposal, and advice from PB as to the methodology for, and amount of, any adjustment required as a result of MMA's review.

The advice received from MMA regarding the reasonableness of Ergon Energy's demand forecast is discussed in chapter 6 of this decision. In summary, the AER notes that MMA maintains its view that the Ergon Energy maximum demand forecasts which underpin its capex forecast are not reasonable, and are overstated when compared with MMA's updated demand forecasts by about five per cent.[375]

The AER has concluded in chapter 6 that Ergon Energy's forecast of maximum demand does not provide a realistic expectation of the demand forecast required to achieve the capex objectives. The AER is therefore not satisfied that Ergon Energy's forecast CIA capex reasonably reflects a realistic expectation of the demand forecast.

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371 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 17.

372 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 18–19.

373 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 19.

374 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 20.

375 MMA, *Maximum demand forecasts for the Ergon Energy region – update addendum*, March 2010, p. 28.

On this basis, the AER considers it appropriate that Ergon Energy's proposed CIA capex be reduced to account for Ergon Energy's overestimation of forecast maximum demand in the next regulatory control period.

The AER notes Ergon Energy's assertion that the adjustment to CIA capex made by the AER in the draft decision was flawed because it:[376]

- relied on sensitivity analysis which significantly overstated the proportion of Ergon Energy's CIA capex which is sensitive to a deferral of forecast demand
- is inconsistent with previous regulatory determinations in assuming that there is a linear and proportional relationship between growth related capex and global maximum demand.

The AER notes that Ergon Energy was unable to define the proportion of CIA capex that is sensitive to the demand forecast, but has presented an analysis undertaken by Huegin indicating the proportion of CIA capex sensitive to the demand forecast is between 55.4 per cent and 86.3 per cent.[377]

The AER notes that, given the lack of available information to conclude specifically what the proportion should be, PB assumed the mid point of the Huegin range (70.9 per cent) to be the proportion of total CIA capex that is sensitive to variation in the demand forecast.[378] The AER considers it is a conservative but reasonable approach, in the absence of more specific information, to take the midpoint of the possible range of values as an appropriate estimate of the percentage of CIA capex that is sensitive to the demand forecast.

The AER acknowledges that the top–down adjustment approach applied in the draft decision provides a high level estimate of the likely impact of demand growth deferral. The AER considers the most accurate and robust method to determine required CIA capex is through a bottom–up process which demonstrates the relationship between the identified need or constraint, the selected option and the capex required. However, in circumstances where the information required to make a detailed bottom–up adjustment is not available, the AER is nonetheless obliged under the NER[379] to provide an estimate of the capex which it considers reasonably reflects a realistic expectation of the demand forecast. In this context, the AER considers the top–down adjustment approach to be a reasonable alternative where a more detailed bottom–up approach to estimating a capex adjustment is not feasible. Contrary to Ergon Energy's assertion, this view is consistent the AER's 2009 NSW regulatory determination, in which the AER accepted top–down adjustments to growth related capex proposed by the NSW DNSPs.[380]

The AER notes PB's advice that the difference between the MMA and Ergon Energy demand forecasts remained essentially similar to the 18 month deferral applied by PB in its previous review, and that it therefore recalculated the 18 month (30 per cent)

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376 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 104.
377 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 6.
378 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 6.
379 See clause 6.12.1(3)(ii) of the NER.
380 AER, *Final decision, NSW DNSPs*, 28 April 2009, p. 128.

demand forecast adjustment on the basis of an assumed sensitivity of CIA capex to the demand forecast of 70.9 per cent.[381]

The AER notes that PB applied the demand forecast adjustment to the CIA capex forecast after accounting for the adjustment arising from reconciliation issues in Ergon Energy's planning documentation.[382] The AER considers this to be an appropriate approach which avoids double counting between the two adjustments.

AER conclusion

The AER requested Ergon Energy model the impact of the AER's decision on proposed CIA growth capex. Ergon Energy advised that the adjustment to forecast CIA growth capex is a reduction of $500 million ($2009–10).[383] The AER notes that Ergon Energy adopted a bottom–up approach in modelling the demand forecast related component of this adjustment. As discussed above, the AER agrees this is a more accurate and robust approach to forecasting capex requirements than a high level top–down approach, where the requisite information is available.

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast CIA growth capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed CIA growth capex by $500 million ($2009–10) 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.

CICW capex

Ergon Energy did not accept the AER's reduction to proposed CICW capex, and proposed a revised forecast reflecting a change in forecasting methodology for large CICW capex.[384]

The AER notes that Ergon Energy's revised regulatory proposal relied on dwelling stock growth as the forecast driver for all categories of CICW expenditure.[385] Given the concerns raised by the AER in the draft decision regarding the application of dwelling stock growth as a driver of commercial and industrial CICW expenditure, the AER sought advice from PB on the prudence and efficiency of Ergon Energy's revised CICW capex forecast.

The AER notes that due to data limitations, Ergon Energy's consultant Huegin was unable to conclude that growth in domestic and rural connections was a driver of small commercial and industrial connections. The AER notes that Huegin in fact identified a relationship between small commercial and industrial expenditure and

[381] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 8.
[382] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 21.
[383] Ergon Energy, response to modelling request, 22 April 2010.
[384] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 110.
[385] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 110.

Queensland (minus Brisbane) non–residential construction costs, and used this to support the validity of Ergon Energy's forecast based on dwelling stock growth.[386]

The AER does not consider the fact that a separate forecast based on a different methodology aligns with Ergon Energy's forecast provides strong evidence that Ergon Energy's forecast is therefore reasonable, particularly as it has not been demonstrated that the forecasts move together or that the apparent correlation would continue into the future. The AER therefore considers that the analysis presented by Huegin in support of Ergon Energy's revised regulatory proposal does not demonstrate causality between dwelling stock growth forecasts and commercial and industrial connections.

The AER notes that Ergon Energy's analysis supporting the use of dwelling stock growth as the driver for forecasting all CICW capex categories, including large connections, is based on an identified correlation between the number of domestic and rural customer connections and total CICW capex.[387] The AER accepts that this analysis demonstrates that total CICW capex increases with the number of domestic and rural connections. However, the AER does not consider that this demonstrates causality between dwelling stock growth and commercial and industrial connections.

The AER also notes PB's conclusion that causality between the driver and the forecast had not been adequately demonstrated, and that it was unable to conclude that the revised CICW capex forecast was prudent and efficient.[388] Based on PB's advice, and its own review, the AER considers that Ergon Energy's revised regulatory proposal has not provided sufficient persuasive new information to alter the conclusion regarding proposed CICW capex set out in the draft decision. The AER therefore concludes that Ergon Energy's revised proposed CICW capex is not prudent and efficient.

The AER notes the criticisms of PB's alternative CICW forecasting model, on which the adjustment set out in the draft decision was based, as outlined in Ergon Energy's revised regulatory proposal.[389] The AER notes that PB accepted that it had used incorrect historical connections data as a modelling input, which had the effect of understating its forecast for CICW capex in the next regulatory control period. However, regarding the model itself, the AER notes that PB did not consider any new and substantive information had been provided as part of Ergon Energy's revised regulatory proposal to suggest that a more reasonable or detailed forecasting approach was achievable. The AER also notes that Ergon Energy's revised regulatory proposal reduced the number of forecasting drivers used from two to one, thereby removing the additional level of rigour identified by Huegin as arising from Ergon Energy's more granular forecasting approach.[390]

The AER notes that PB maintained its advice that its alternative forecasting model, based on average historical numbers and costs of customer connections escalated for anticipated growth in total customer numbers, provided for a prudent and efficient

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386 Huegin Consulting Group, *Review of Qld draft determination & Parsons Brinckerhoff report on Ergon Energy's regulatory proposal*, 18 January 2010, p. 30.

387 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 26.

388 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 26–27.

389 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 111.

390 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 27–29.

level of CICW capex which ensured future customer connection activities at levels consistent with Ergon Energy's recent historical experience.[391] The AER has reviewed and agrees with PB's advice in this regard, and notes that PB's methodology provides for a real increase in CICW capex in the next regulatory control period.

In the absence of sufficient evidence to support the appropriateness of Ergon Energy's use of dwelling stock growth to forecast all categories of CICW capex, the AER has concluded that Ergon Energy's forecast of CICW capex is not prudent and efficient. The AER considers that PB's alternative forecasting model provides an appropriate alternative basis for estimating a prudent and efficient level of CICW capex in the next regulatory control period, given it is based on observed historical costs and realistic forecasts of customer growth. The AER also considers that the corrected historical connections data as advised by Ergon Energy should be used as inputs to the forecasting model.

The AER requested Ergon Energy model the impact of the AER's decision on proposed CICW growth capex. Ergon Energy advised that the adjustment to forecast CICW growth capex is a reduction of $402 million ($2009–10).[392]

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast CICW growth capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed CICW growth capex by $402 million ($2009–10) 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.

7.4.5.2 Asset replacement capex

AER draft decision

Revised regulatory proposal

Ergon Energy reinstated the amount proposed for this purpose in its original regulatory proposal, adjusted to account for changes in cost escalators and overheads.[393]

Ergon Energy's revised forecast asset replacement capex is set out in table 7.16.

Table 7.16: Ergon Energy's revised forecast asset replacement capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Asset replacement	181.2	222.6	261.7	285.9	305.0	1256.3

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, p. 122.

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391 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 30.
392 Ergon Energy, response to modelling request, 22 April 2010.
393 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 113.

Ergon Energy provided additional information in its revised proposal to support its forecasts in the three areas where the AER and PB were dissatisfied.[394]

Ergon Energy noted that its forecast asset replacement is split into a defect program and a condition based program. Defect program forecasts are based on the asset population and known historical defect rates from the asset inspection program.[395] Condition based program forecasts are based on asset condition determined from various maintenance and testing programs, an analysis of network performance and analysis of dangerous electrical events. Ergon Energy stated:[396]

> Where condition information is not known, asset age is used as a proxy for condition for the purposes of prioritising areas of the network for analysis and also for financial forecasting purposes. While asset age is used in this manner, age is not used as the basis for asset replacement. Contrary to the conclusion drawn by PB in their report, replacement is only undertaken following analysis of the performance and condition of assets.

Ergon Energy engaged Huegin[397] to review its forecast asset replacement capex. Ergon Energy noted that Huegin found that:[398]

- Ergon Energy uses the most appropriate maintenance method given the assets and circumstances, whereby its Preventative Maintenance is based upon predictive inspections;
- Age is used to forecast replacement volumes, rather than for identifying assets that are to be replaced; and
- Replacement of assets is based on asset condition.

Ergon Energy stated that it replaces assets based on condition based inspections and assessments and disagreed that its forecast replacement capex is based on age.[399]

Ergon Energy noted that the AER and its consultant reviewed 4 of 26 asset classes which comprised 48 per cent of forecast replacement capex and used the outcome of that review to make an adjustment to the entire replacement category. It stated that a statistical test applied by the AER and its consultant requires that a hypothesis be framed. It noted that a hypothesis was not stated in the draft decision.

Pole top replacement program

Ergon Energy provided the Noonan and Brookes report[400] into the current Elevated Work Platform (EWP) inspection program noting that replacements are likely to increase compared to the current business as usual approach.[401] Ergon Energy engaged Huegin to report on the appropriateness of the volume forecasts. Huegin

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394 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 113.
395 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 114.
396 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 114.
397 Ergon Energy, *Revised regulatory proposal*, January 2010, RP938c Huegin Report for Ergon Energy, 18 January 2010.
398 Ergon Energy, *Revised regulatory proposal*, January 2010, p.114.
399 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 114.
400 Kathleen Noonan and Stephen Brooks, *Distribution pole head rot management project*.
401 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 115–116.

supported Ergon Energy's view that the business as usual level of pole top replacement is unsustainable and increased replacements were required.[402]

Conductor and connector replacement program

Ergon Energy reinstated its original forecast for conductor and connector capex. It provided specific information regarding replacement volume forecasts and clarified its use of asset condition as opposed to asset age for the conductor and connector replacement program.[403]

Ergon Energy also stated that Huegin reviewed its approach to forecasting replacement volumes and asset replacement identification, finding that Ergon Energy's approach was appropriate.[404]

Zone substation transformer replacement capex

Ergon Energy stated that 31 per cent of its forecast zone substation transformer replacement capex is for the purchase of strategic spares for the replacement of failed in–service transformers. It indicated that the remaining allowance is set aside for its transformer replacement program and planned replacement of transformers prior to failure.

Ergon Energy provided information highlighting the costs associated with in–service transformer failure. It provided an example of a transformer failure with direct costs of $400 000 and estimated the customer loss of supply cost to be $1.5 million. It resubmitted information setting out transformer failure rates and stated that it was moving to a more pro–active approach to transformer management including transformer dry outs and replacement prior to failure. Ergon Energy provided additional transformer failure rate modelling and stated that based on that modelling, its forecast transformer replacement capex is the absolute minimum that a prudent and efficient operator in the same circumstances would require.[405]

Consultant review

In relation to forecast replacement volumes, PB noted Ergon Energy's statement that where asset condition is unknown, asset age is used for financial forecasting purposes. PB also noted Huegin's finding that asset age is used to forecast replacement volumes rather than for identifying assets to be replaced. PB accepted that, in practice, Ergon Energy makes replacement decisions based on performance and condition. However, PB considered that Huegin's statements confirm concerns of over-forecasting expenditures due to the use of age in the financial modelling.[406]

PB noted Ergon Energy's claim that the adjustment of asset replacement capex based on business as usual expenditure was logically and statistically flawed. PB disagreed with this view, on the basis that it incorrectly assumed that the adjustment was

[402] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 116.
[403] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 116–117.
[404] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 118.
[405] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 120–121.
[406] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 34.

determined using a statistical test based on the sample reviewed, which was not the case.[407]

PB noted Huegin's claim that business as usual levels of expenditure are inappropriate given Ergon Energy's recent underspending on asset replacement. PB considered that its use of historical growth trend to determine business as usual expenditure levels reasonably accounts for any periods of under expenditure. PB said this was evident in the 55 per cent increase on current period expenditure derived as a result of its recommendation.[408]

PB assessed reviews that Ergon Energy provided in its revised proposal for three of the four asset categories previously reviewed by PB. PB's key findings in relation to each of the three asset categories are summarised below.

Pole top replacement

- PB did not identify any analysis to support Ergon Energy's conclusion that the current (business as usual) approach to pole top replacement is critically flawed and does not deliver the required level of reliability.[409]

- PB re-examined Ergon Energy's network asset replacement maintenance capital expenditure operating expenditure summary (NARMCOS) model and found that information in the model does not appear to reconcile and that the basis of the replacement volume forecasts within the model is not apparent.[410]

- It was not apparent to PB if and how Ergon Energy had scaled pole top defect rates for Far North Queensland for application elsewhere.[411]

Conductor and connector replacement

- PB noted that while Ergon Energy's revised Conductor and Connector Replacement Program document included a significant amount of information, it did not demonstrate the prudence and efficiency of the proposed level of capex.[412]

- PB accepted that Ergon Energy may not have age and quantity data for conductors, as stated by Huegin, but considered it very clear from other documentation that Ergon Energy uses other data as proxies for conductor age in its replacement analysis, including year of manufacture, pole age and sub-transmission line age.[413]

- PB disagreed with Huegin's view that Ergon Energy's approach to forecasting replacement volumes was appropriate given the information available. PB noted that other information that is essential to the development of a robust replacement

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407 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 34–35.
408 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 35.
409 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 37.
410 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 37.
411 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 38.
412 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 38.
413 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 38.

volume forecast was known, or could be expected, to be available to Ergon Energy.[414]

- PB indicated that it would expect economic and risk assessments to be undertaken when preparing a replacement volume forecast, in order to further support the proposed level of expenditure and to demonstrate that it was the prudent and efficiency level of investment.[415]

Zone substation transformer replacement

- PB noted that Ergon Energy's revised proposal referenced two documents already assessed by PB which it concluded did not demonstrate a sound basis for the proposed forecasts.[416]

- PB re-examined another document it had previously reviewed, related to condition assessments of transformers, and noted that the test dates ranged from 1999 to 2005. PB considered these tests to be quite dated and therefore of questionable relevance to the current state of the equipment.[417]

- PB noted Ergon Energy's reliance on an asset replacement model developed by Huegin. PB considered that the model was likely to indicate expenditure on transformers that is above prudent and efficient levels due to an assumed transformer life of 50 years. Given the criticality of this assumption, and the lack of information to substantiate its validity, PB concluded that Huegin's model did not provide a prudent and efficient forecast of transformer replacement capex.[418]

Having examined the information provided in Ergon Energy's revised proposal in relation to the specific asset replacement categories previously reviewed by PB, PB found no new or additional information to demonstrate the prudence and efficiency of Ergon Energy's proposed asset replacement capex. Based on this conclusion, PB recommended that Ergon Energy's revised asset replacement capex proposal be reduced by $123 million ($2009–10).[419]

AER considerations

The AER notes Ergon Energy rejected the draft decision in relation to asset replacement capex and reinstated the amount proposed for this purpose in its original regulatory proposal, adjusted to account for changes in cost escalators and overheads.[420]

The AER notes Ergon Energy agrees with the AER that a condition based approach to replacement is appropriate.[421] The AER also notes Ergon Energy's statement that it does not replace assets based on age and that it replaces assets only after analysing

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[414] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 39.
[415] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 39.
[416] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 39–40.
[417] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 41–42.
[418] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 42.
[419] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 43.
[420] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 113.
[421] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 114.

their condition and performance.[422] However, Ergon Energy also stated that asset age is used for financial forecasting purposes. Ergon Energy also noted Huegin's finding that asset age is used by Ergon Energy to forecast replacement volumes.[423]

Based on this information, the AER accepts that Ergon Energy may only replace assets once their condition has been assessed. However, for the purpose of developing forecasts of asset replacement capex for the next regulatory control period, it is clear that Ergon Energy relies to some extent on asset age information. The AER notes that, in its detailed review of Ergon Energy's revised proposal in relation to asset replacement, PB reached the same conclusion. The AER further notes PB's view that reliance on asset age to forecast replacement is not good practice as it implicitly ignores the condition and operational context of assets and therefore leads to an inefficient forecast.[424]

The AER notes Ergon Energy's comments that the AER's adjustment of Ergon Energy's asset replacement capex was logically and statistically flawed. The AER disagrees with this conclusion because it suggests that the AER based its adjustment of Ergon Energy's asset replacement capex on a statistical relationship between the asset categories that were reviewed in detail by PB and those that were not. As PB pointed out, this was not the case.[425] Rather, based on the AER's review of PB's findings in relation to almost half of Ergon Energy's asset replacement capex, the AER concluded that Ergon Energy had not demonstrated that the total level of asset replacement capex proposed by Ergon Energy was prudent and efficient. Having come to this conclusion, the AER sought to establish a level of asset replacement capex for Ergon Energy during the next regulatory control period that was prudent and efficient. The AER did this with reference to historical business as usual levels of expenditure, as recommended by PB.

The AER notes that Ergon Energy provided additional information in its revised proposal to support its forecasts in the areas where the AER and PB were dissatisfied.[426] The AER notes that PB reviewed this information and found no new or additional information to demonstrate the prudence and efficiency of Ergon Energy's proposed asset replacement capex. Rather, PB identified several issues in relation to each asset category which indicate that the proposed level of asset replacement capex proposed by Ergon Energy is not prudent and efficient.[427] Having reviewed the material presented by Ergon Energy and PB's assessment, the AER has a number of concerns, including that:

- asset age has been used to forecast asset replacement capex, including in the model for transformer replacement developed by Huegin, which raises concerns about over-estimation

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422 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 113.
423 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 113.
424 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 34.
425 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 35.
426 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 113.
427 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 36–43.

- there appear to be problems with Ergon Energy's asset replacement modelling, including reliance on outdated data and internal inconsistencies, which raise doubts about the accuracy of the forecasts produced

- forecasts of asset replacement volumes do not appear to be informed by the most suitable information available to Ergon Energy, including historical failure rates, defect rates, replacement rates and incident records, which, again, raises doubts about forecast accuracy.

As a result of these concerns, the AER confirms its draft decision 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 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).[428]

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's revised forecast asset replacement capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's revised proposal for asset replacement capex by $119 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.

7.4.5.3 Reliability and quality improvement capex

AER draft decision

The AER considered 61 per cent of Ergon Energy's forecast reliability and quality improvement capex. The programs reviewed were the supervisory control and data acquisition (SCADA) acceleration strategy and the feeder improvement program. The AER accepted the forecast capex for the SCADA acceleration strategy however it did not accept Ergon Energy's forecast capex for the feeder improvement program, noting that:[429]

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[428] Ergon Energy, response to modelling request, 22 April 2010.
[429] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 546.

- the individual benefits of each feeder improvement were not recognised or the timeframe over which they should be addressed was not provided

- the causes of poor performance were not recognised, and it was unclear how the proposed expenditure would address the performance issues and how the proposed costs had been determined

- other capex and opex expenditures were identified that will also target the same performance problem, and these expenditures had not been taken into account in the development of the feeder improvement program.

The AER considered that Ergon Energy's forecast reliability and quality improvement capex should be maintained at current regulatory period levels with an allowance for the SCADA acceleration program. Accordingly the AER reduced Ergon Energy's reliability and quality improvement capex by $35 million ($2009–10).[430]

Revised regulatory proposal

Ergon Energy provided clarification on the AER's concerns set out in the draft decision.

Fifty worst performing feeders

Ergon Energy stated that it identifies its under performing feeders and reports on, and conducts additional analysis on, its 50 worst performing feeders. Taking deliverability considerations into account, Ergon Energy stated that it targets 8.5 feeders per year.[431] On this basis, Ergon Energy stated that its feeder improvement program is based on balancing the identified need with resource constraints.[432]

Investigation of poor performance

Ergon Energy stated that it conducts causal analysis on feeder poor performance. The analysis is reported in its annual network performance reports. It also stated that the Huegin report provides further evidence of causal analysis in the development of the feeder improvement program.[433]

Benefits and timing

Ergon Energy stated that '… individual feeder improvement benefits identification and timing considerations are inherent in the Feeder Improvement Program...'[434] It stated that timing is dependent on prioritisation of need and resource and the capacity planning process within Ergon Energy.[435]

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430 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 546.
431 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 124.
432 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 124.
433 Ergon Energy, *Revised regulatory proposal*, January, 2010 p. 124.
434 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 124.
435 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 124.

Capex/opex overlap

Ergon Energy stated its forecast for feeder improvement was a provision to address feeder performance, to the extent that:[436]

- forecasts are based on assumptions of future requirements
- reliability improvement options are based on the identification of actual worst performing feeders and causes of reliability problems which change over time and are difficult to predict.

Ergon Energy stated it is required to consider maintenance and operation solutions concurrently with reliability initiatives when determining the most appropriate strategy for improving reliability of poorly performing feeders.[437]

Issues using historical capex

Ergon Energy stated using historical expenditures as the basis for forecasting future reliability and quality improvement capex represents a failure to consider the circumstances of Ergon Energy in accordance with the capex criteria. It stated:[438]

- PB did not assess the prudence and efficiency of current regulatory control period reliability and quality improvement capex
- actual current regulatory control period reliability and quality improvement capex is much lower than planned due to reallocation of resources to meet regulatory obligations to connect customers
- the approach does not consider the likely requirement for reliability improvement capex in the next regulatory control period nor the reduction of minimum service standard targets.

Revised forecast reliability and quality improvement capex

Ergon Energy's revised forecast reliability and quality improvement capex is the same as its forecast reliability and quality improvement capex set out in its regulatory proposal with minor adjustments for escalators and shared costs (overheads). Ergon Energy's revised forecast reliability and quality improvement capex is set out in table 7.17.

Table 7.17: Ergon Energy's revised forecast reliability and quality improvement capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Reliability and quality improvement	18.5	21.5	25.2	29.0	30.9	125.0

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, p. 127.
Note: Totals may not add due to rounding.

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[436] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 124–125.
[437] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 125.
[438] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 125.

Consultant review

Based on its review of proposed reliability and quality improvement capex, PB considered that Ergon Energy had not demonstrated the proposed capex was prudent and efficient.

PB addressed the following key issues, primarily concerning the proposed feeder improvement program.

Level of investment

PB acknowledged that Ergon Energy was targeting a specific number (42.5) of feeders and that the title '50 worst performing feeders' was a reporting convention. However, PB considered that Ergon Energy had not provided sufficient documentation to demonstrate that the proposed $40.2 million of capex for worst performing feeders was a prudent or efficient level of investment for this number of feeders. PB considered that demonstrating the prudence and efficiency of such projects would require analysis showing the expected number of non-performing feeders against recognised performance criteria, as well as supporting trend and root-cause analysis. PB also noted that supporting risk analysis and analysis of avoidable costs would improve the robustness and clarity of the analysis.[439]

Benefits and timing of investment

PB noted and accepted the conclusion of Huegin[440] that Ergon Energy considered the benefits and timing of investment in reliability and quality improvement in an operational context at the time of expenditure. However, with the exception of system average interruption duration index (SAIDI) benefits, PB considered that Ergon Energy did not demonstrate the specific value of investment benefits. Further, PB considered that Ergon Energy did not demonstrate the scope of work required to achieve the proposed SAIDI savings or the timing of these benefits. As a result, PB maintained its position that Ergon Energy had not demonstrated consideration of the benefits and timing of the proposed capex for the next regulatory control period.[441]

PB also noted that it was unable to identify any benefits relevant to the proposed reliability and quality improvement capex in the Network Management Plan (NMP) and noted that Ergon Energy specifically stated that 'financial targets beyond 2009–10 have not been included in this NMP'.[442]

Causal analysis of poor performance

PB stated concern that Ergon Energy did not explicitly identify how the causes of poor performance amongst the identified feeders were to be targeted by the proposed $40.2 million capex. PB concluded that the proposed capex appeared to be a general provision for feeder improvement works rather than a program of specific targeted expenditure. As such, PB considered that Ergon Energy did not reasonably demonstrate that the proposed investment, at a unit cost of $653 000 per feeder

439 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 45–46.

440 Huegin Consultant Group, *Review of Queensland draft determination report and Parsons Brinckerhoff report on Ergon Energy's regulatory proposal*, January 2010, p. 55.

441 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 46–47.

442 Ergon Energy, *Network Management Plan Part A, Electricity Supply for Regional Queensland 2008/09 to 2012/13*, AR402, and Part B, AR445.

(excluding overheads), was the efficient level of investment needed to address the causes of poor performance.[443]

Duplicate funding

PB acknowledged the procedural controls implemented by Ergon Energy were an essential part of prudent and efficient business management. However, PB stated such controls did not demonstrate that the proposed level of capex did not include other funding that addressed the same identified need.[444]

Basis of the adjustment

PB noted Ergon Energy considered the adjustment made to the reliability and quality improvement capex proposal in the draft decision did not meet the capex criteria.[445] Ergon Energy rejected the adjustment on the grounds that its prudence and efficiency had not been assessed.[446] PB considered that its review did not identify any factors to indicate that reliability and quality improvement capex forecasts should differ significantly from current period expenditure. PB considered that, as the QCA had reviewed and approved Ergon Energy's capex for the current period, it was likely that this represented a reasonably prudent and efficient benchmark level of expenditure.[447]

PB noted Ergon Energy considered the likely requirement for reliability improvement expenditure under tightening MSS targets was not accounted for in the method applied in PB's review. However, PB stated that the October 2009 performance reliability report demonstrated a trend of consistently improving historical reliability performance against minimum service standards (MSS) and service target performance incentive scheme (STPIS) targets. PB therefore considered that the reduction of the MSS targets did not have a significant bearing on the use of historical expenditure as a prudent or efficient benchmark.[448]

PB also noted Ergon Energy considered historical expenditure was much lower than planned due to resource reallocation and that the method of adjustment employed by PB did not consider Ergon Energy's circumstances. PB noted an average historical underspend of $1.9 million per year that was not accounted for in PB's original calculations and revised its recommendations accordingly.[449]

Based on its assessment of Ergon Energy's revised proposal, PB maintained its recommendation that expenditure for reliability and quality of supply in the next regulatory control period be maintained at current period levels (adjusted upwards to account for the $1.9 million per year underspend) plus an allowance for the proposed SCADA acceleration strategy. PB's recommended adjustments are set out in table 7.18.

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443 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 47–48.
444 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 48–49.
445 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 49.
446 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 125.
447 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 49.
448 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 50–51.
449 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 51.

Table 7.18: Recommended capex for Ergon Energy's reliability and service quality improvement ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy revised regulatory proposal	18.5	21.5	25.2	29.0	30.8	125.0
PB adjustment	–0.7	–2.7	–5.4	–8.1	–9.6	–26.5
PB recommendation	17.8	18.8	19.8	20.9	21.2	98.5

Source: PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 51.
Note: Totals may not add due to rounding.

AER considerations

The AER notes that Ergon Energy did not accept the AER's rejection of the feeder improvement program and that it included the program in its revised regulatory proposal and sought to address the specific concerns raised by the AER and PB.[450]

The AER reviewed the material provided by Ergon Energy and still has a number of concerns:

- Level of investment – while Ergon Energy has provided general justification for targeting 42.5 feeders, the AER considers Ergon Energy has not sufficiently demonstrated that this number of feeders or the proposed $40.2 million investment is efficient or prudent. The AER notes that PB considered Ergon Energy had not sufficiently demonstrated that it had undertaken the necessary analysis to justify the proposed $40.2 million capex.[451]

- Benefits and timing of the investment – the AER considers Ergon Energy has not clearly demonstrated the magnitude or timing of benefits expected as a result of the feeder improvement program. For example, the AER notes Ergon Energy stated the timing of investment is dictated by the prioritisation process in the feeder improvement program.[452] The AER considers this implies the timing of investment is not known in advance or forecasted. The AER notes PB's view that Ergon Energy does identify specific benefits and timing of the capex in an operational context at the time of investment.[453] The AER considers Ergon Energy has not demonstrated the prudence and efficiency of expenditures in advance of the regulatory control period, as is necessary for the AER to accept the program.

- Causal analysis justifying the investment – the AER considers Ergon Energy has not clearly demonstrated how the proposed level of investment is to be targeted at causes of poor performance. It also notes Ergon Energy does undertake causal analysis of feeder unreliability. The AER also notes Ergon Energy determined

450 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 123–128.
451 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 45–46.
452 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 127.
453 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 47.

proposed costs based on an average cost per feeder.[454] However, the AER considers Ergon Energy has not demonstrated how these average costs will be efficiently and prudently allocated to target problems identified in the causal analysis. The AER notes PB did not identify any new information in Ergon Energy's revised regulatory proposal to demonstrate the efficiency of the targeted investment.[455]

- Duplication of funding – the AER is concerned that the proposed level of capex does not adequately reflect the issue of funding overlap with other capex and opex programs. The AER notes Huegin concluded that Ergon Energy's processes are sufficient to ensure that expenditure allocated from the feeder improvement program will not overlap with other funding.[456] The AER also notes Ergon Energy has indicated that, in the event funding is not required for the allocated feeders, Ergon Energy can target alternative poor performing feeders to improve SAIDI performance.[457] However, the AER considers that such an approach may lead to inefficient investment in feeders where the causes of poor performance would not have been considered significant in advance. The AER notes PB did not identify any new information in Ergon Energy's revised regulatory proposal to demonstrate the potential for duplication of funding was adequately addressed in the proposed capex.[458]

The AER notes that, in its review of Ergon Energy's reliability and quality improvement capex in the revised regulatory proposal, PB identified an average historical underspend of $1.9 million against the QCA approved benchmark for historical spending.[459] The AER accepts that the QCA approved levels of historical spending represent a prudent and efficient benchmark. As such, the AER accepts PB's recommendation to account for the $1.9 million average historical underspend in calculating its revised adjustments to Ergon Energy's reliability and service quality improvement capex.

The AER accepts that reliability and quality improvement capex should be maintained at current period levels, adjusted to account for the $1.9 million per year historical underspend, plus an allowance for the SCADA acceleration strategy. The AER requested Ergon Energy to model the impact of the AER's decision on reliability and service quality improvement capex. Ergon Energy advised that the adjustment to forecast reliability and quality improvement capex is a reduction of $26 million ($2009–10).[460]

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not

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454 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 127.
455 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 48.
456 Huegin Consultant Group, *Review of Queensland draft determination report and Parsons Brinckerhoff report on Ergon Energy's regulatory proposal*, January 2010, pp. 60–61.
457 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 127.
458 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 49.
459 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 51.
460 Ergon Energy, response to modelling request, 22 April 2010.

satisfied that Ergon Energy's forecast reliability and quality improvement capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed reliability and service quality improvement capex by $26 million results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and is the minimum adjustment necessary for the capex component to comply with the NER. In coming to this view the AER has had regard to the capex factors.

7.4.5.4 Non–system capex—major property projects

AER draft decision

The AER concluded that the prudence and efficiency of the major property project expenditures proposed by Ergon Energy had not been adequately demonstrated. The AER noted Ergon Energy had been unable to provide business case documentation or other supporting documentation to justify the major property project expenditures proposed.[461]

The AER concluded Ergon Energy's non–system land and buildings capex forecast should be reduced by $188 million ($2009–10). This reflected the removal of all new major building projects proposed, to allow for a business as usual level of expenditure.[462]

Revised regulatory proposal

Ergon Energy submitted a revised capex forecast for major property projects largely reinstating its original capex proposal. Ergon Energy advised its major property projects were required to:[463]

- comply with regulatory building requirements
- comply with safety and environmental requirements
- achieve operational performance outcomes
- effectively manage potential post–disaster (cyclone) operational responses.

Ergon Energy submitted additional investment justification for the proposed projects, including field asset condition reports, site assessments, business cases and recommendation documentation.[464]

Ergon Energy's non–system land and buildings capex forecast was updated in the revised regulatory proposal to reflect refined project definitions based on updated user requirement specifications, refined design development details, updated cost plans and shifts in priorities.[465] Ergon Energy submitted a revised forecast for non–system

[461] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 563.
[462] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 564.
[463] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 129.
[464] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 131.
[465] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 131.

property capex of $264 million ($2007–08), a reduction of $3 million from its original regulatory proposal.[466]

Consultant review

PB reviewed Ergon Energy's revised regulatory proposal and supporting material provided in relation to the major property projects component of the non–system capex proposal.

PB noted Ergon Energy had provided significant new information supporting its proposed property capex, including in relation to the corporate property strategy, deliverability, major project prioritisation, business case development and alternative project options.[467]

In relation to the corporate property strategy, PB noted Ergon Energy provided an explanation of project changes that had occurred over time through the development of work scopes, cost estimates, asset market values and implementation prioritisation since the property strategy was developed in 2006. PB noted that this ongoing revision approach explained the variations in major project scopes and costs since 2006. PB concluded that on the basis of the new information provided, it was satisfied Ergon Energy's corporate property strategy was up to date and relevant as an overarching planning framework for corporate property in the next regulatory control period.[468]

PB noted Ergon Energy reviewed the relative prioritisation of its projects, and this had resulted in adjustments to the proposed timing of projects, such as:

- the deferral of the largest property capex project, Townsville, from 2010–11 to 2012–13
- the removal of the data centre building, which was previously also proposed for implementation in the first half of the next regulatory control period.

PB considered these changes reduced the magnitude of the program in the first two years of the next regulatory control period and smoothed the schedule of major property works. PB concluded that these changes assisted in demonstrating that delivery of the property program according to the proposed schedule was reasonable and achievable. PB also considered this reprioritisation indicated that the proposed timing for implementation of major projects was prudent.[469]

In assessing the efficiency of the proposed property projects, PB reviewed the scenario options assessment presented in the business case document for each site. PB noted that:[470]

466 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 130.
467 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 60–61.
468 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 62.
469 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 62–63.
470 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 63.

- a scoring methodology had been applied to evaluate both financial and non–financial aspects of each option
- the cumulative weighting of financial to non–financial criteria applied was 40 per cent financial to 60 per cent non–financial
- no sensitivity analysis was apparent in the documentation to consider the sensitivity of the recommended option to the weighting system
- a comparison of financial (NPV) considerations alone indicates that business as usual (scenario 1) is the preferred option for all major projects except Mackay
- the comparative options assessment indicated a preference to develop new facilities or upgrade existing facilities (scenario 2) in all cases.

PB considered that the use of a scoring methodology was in principle, a sound approach but could be unreasonably biased, lack consistency in application and difficult to interpret without appropriate development, calibration and careful application.[471]

Given the importance of financial cost–benefit outcomes in an investment proposal setting, PB conducted a simple sensitivity analysis test to determine the effect on the preferred option outcomes of applying an even 50–50 weighting to financial and non–financial key result areas (KRAs). PB found that the scenario 2 option remained the preferred option over the business as usual scenario 1 approaches for all major projects with the exception of Townsville, though the preference for scenario 2 for Rockhampton was marginal. PB therefore concluded that the analysis outcomes were not systemically sensitive to the relative weighting assigned to non–financial criteria, but that at a project level decisions could be altered.[472]

In order to compare financial efficiency across projects, PB calculated a value of 'dollars per weighted KRA index point' for each major project, to provide an indication of the implied dollar value being placed on the non–financial benefits associated with each project. PB found that the dollars per weighted KRA index point differed significantly between projects to achieve the preferred option in each case, ranging from approximately $1 million for Cairns up to $7 million for Townsville and $10 million for Rockhampton.[473]

PB noted that ideally the dollar value per weighted KRA index point should be consistent across all business cases, to provide a benchmark on which to compare projects. Given that the dollars per weighted KRA index point for Townsville and Rockhampton were significantly higher than for the other four projects and the average for all projects, PB concluded that the Townsville and Rockhampton projects were the least cost efficient and that the value of non–financial benefits compared to

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[471] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 63.
[472] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 64–65.
[473] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 65.

financial costs was relatively low for these projects compared to the other four major projects proposed.[474]

In light of this assessment of efficiency, PB reviewed additional information provided by Ergon Energy in support of the Townsville and Rockhampton projects. PB considered that, while it would be prudent to address the safety and capacity issues raised in the site assessment reports, Ergon Energy had not considered any alternatives to address these issues. PB noted that other options could include the movement of activities to a new site or improved management, separation and identification of vehicle and pedestrian access routes. Given these considerations, PB concluded the efficiency of the proposed capex was not demonstrated by the site assessment information.[475]

In summary, PB found that Ergon Energy's corporate property strategy was up to date, the project prioritisation was appropriate and the proposed program of works was deliverable. PB was satisfied that, with the exception of the Townsville and Rockhampton projects, Ergon Energy had demonstrated that all major property projects were prudent and efficient.[476]

With respect to the Townsville and Rockhampton projects, PB considered the projects had not been demonstrated to be prudent and efficient, due to:

- the magnitude of the variance in the dollars per weighted KRA index point above the average
- the sensitivity of the projects to the weighting between financial and non–financial criteria
- the absence of alternative options.

PB recommended that the Townsville and Rockhampton major property projects be removed from the capex forecast for the next regulatory control period.[477] PB's recommended capex allowance for non–system property is shown in table 7.19.

Table 7.19: PB's revised non–system property capex ($2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy revised proposal	128.2	106.9	80.4	34.4	38.4	388.2
PB adjustment	–29.0	–21.8	–45.5	–21.8	–31.9	–148.0
Recommended capex	99.2	85.1	36.9	12.6	6.5	240.3

Source: PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 67.
Note: Totals may not add due to rounding.

474 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 65–66.
475 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 65–66.
476 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 66–67.
477 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 67.

AER considerations

The AER reviewed Ergon Energy's revised regulatory proposal and supporting documentation provided in relation to the revised non–system capex proposal for major property projects, and sought advice from PB on the prudence and efficiency of the expenditures proposed.

The AER notes that Ergon Energy has submitted additional investment justification for the proposed projects which seeks to address concerns in relation to the corporate property strategy, project prioritisation and deliverability, business case development and alternative project options.[478]

In relation to the corporate property strategy, the AER notes PB's conclusion that Ergon Energy's corporate property strategy is up to date and relevant as an overarching planning framework for corporate property in the next regulatory control period.[479]

The AER notes that Ergon Energy reviewed the prioritisation of projects after completing the project business cases and, as a result of this review adjusted the proposed timing of projects, including deferring the largest property capex project by two years.[480] The AER considers that Ergon Energy has, therefore, demonstrated that the property program has been prioritised and is based on a delivery timetable that appears reasonable and prudent.

The AER notes that PB, in assessing the efficiency of the individual property projects proposed, found that a comparison of financial considerations alone indicates that the business as usual scenario (scenario 1) is the preferred option for all major projects except Mackay. However, after accounting for non–financial KRAs such as asset effectiveness, safety and employee satisfaction, the option to develop new facilities or upgrade existing facilities (scenario 2) was identified as preferred in all cases.[481]

The AER notes that PB conducted a simple sensitivity analysis test to determine the effect on the preferred option outcomes of applying an equal 50–50 weighting to financial and non–financial KRAs. PB found that the scenario 2 option remained the preferred option over the business as usual scenario 1 option for all major projects with the exception of Townsville, though the preference for scenario 2 for Rockhampton was marginal. The AER notes PB's conclusion that the analysis outcomes were not systemically sensitive to the relative weighting assigned to non-financial criteria, but that at a project level decisions could be affected.[482]

The AER accepts non–financial risks and measures are relevant considerations that can offset costs in the context of investment planning, and notes PB's advice that the use of a scoring methodology is, in principle, a sound approach.[483] The AER does, however, consider that care needs to be taken to ensure that measures of non–financial benefits are appropriately calibrated and applied with consistency to ensure that the

478 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 60–61.
479 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 62.
480 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 62–63.
481 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 63.
482 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 64–65.
483 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 63.

resulting assessment can be relied upon to reasonably identify efficient project options.

The AER notes that PB calculated a value of dollars per weighted KRA index point for each major project, to provide an indication of the implied dollar value placed by Ergon Energy on the non–financial benefits associated with each project. The AER notes PB's view that the dollar value per weighted KRA index point should be consistent across all business cases, to provide a benchmark comparator of efficiency across projects. The AER notes PB's findings that the dollars per weighted KRA index point differed significantly between projects to achieve the preferred option in each case, and that the values for Townsville ($7 million) and Rockhampton ($10 million) were significantly higher than the average (less than $5 million).[484]

The AER therefore considers, based on its review of PB's analysis, that the Townsville and Rockhampton projects are substantially less cost efficient than the other four property projects and that the value of non–financial benefits compared to financial costs is relatively low for these projects.

Further, in relation to the Townsville and Rockhampton projects, the AER notes PB's view that, while it would be prudent to address the safety and capacity issues raised in the relevant site assessment reports, Ergon Energy had not appropriately considered alternative options to address these issues. As such, the AER notes that PB considered the efficiency of the proposed capex was not demonstrated by the site assessment information.[485]

Having reviewed Ergon Energy's revised regulatory proposal and the advice from PB, the AER considers that Ergon Energy has addressed many of the concerns raised by the AER in its draft decision regarding the prudence and efficiency of the major property projects proposed. The AER is therefore satisfied that, with the exception of the Townsville and Rockhampton projects, Ergon Energy has demonstrated that the revised capex proposal for major property projects is prudent and efficient.

In relation to the Townsville and Rockhampton projects, the AER considers that the magnitude of the difference in the dollars per weighted KRA index point above the average, casts significant doubt on the efficiency of these projects given the substantially higher cost of achieving non–financial benefits at these sites. This, combined with the sensitivity of these projects to the assumed weighting between financial and non–financial criteria, and the absence of alternative options for these projects, leads the AER to conclude that these projects have not been demonstrated to be prudent and efficient.

Accordingly, the AER considers that the proposed cost of the Townsville and Rockhampton major property projects should be removed from Ergon Energy's non–system capex forecast for the next regulatory control period.

The AER requested Ergon Energy model the impact of the AER's decision on non–system capex for major property projects. Ergon Energy advised that the

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484 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 65.
485 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 65–66.

adjustment to forecast non–system capex is a reduction of $107 million ($2009–10).[486]

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal and PB's report, the AER is not satisfied that Ergon Energy's forecast non–system capex for major property projects reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed demand driven capex by $107 million ($2009–10) 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.

7.4.5.5 Non–system capex—ICT systems

AER draft decision

The AER noted Ergon Energy was unable to provide business case documentation in support of the change program costs, which formed a significant part of Ergon Energy's proposed non–system ICT capex. The AER was not satisfied, on the basis of the information provided by Ergon Energy, that the capex associated with the change program was prudent and efficient.

The AER concluded that all costs associated with the change program should be excluded from Ergon Energy's proposed ICT systems capex, resulting in a reduction in the capex forecast of $65 million ($2009–10).

Revised regulatory proposal

Ergon Energy revised its proposed capex for the change program in response to the draft decision, reducing proposed expenditures from $10 million per year (excluding overheads) to $2 million per year.[487]

Ergon Energy's revised regulatory proposal clarified the type of projects to be implemented under the change program as being non–ICT projects aimed at supporting transformational cultural change across the business. The forecast level of change program activity was based on expenditure in the 2007–08 year.[488]

Consultant review

PB reviewed Ergon Energy's revised regulatory proposal in relation to the change program, and also sought additional information from Ergon Energy to ascertain the underlying prudence and efficiency of the proposed expenditure. PB noted Ergon Energy was unable to provide business cases for projects in the next regulatory control period (as these would be developed as required for internal purposes), but it

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486 Ergon Energy, response to modelling request, 22 April 2010.
487 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 128.
488 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 129.

did provide two business cases to illustrate examples of projects in the change program from previous years.[489]

PB reviewed the two business cases provided by Ergon Energy and found the size of the projects suggested the $2 million per annum forecast for the change program appeared reasonable. However, PB did not consider the provision of selected historical business cases was sufficient to justify expenditure for the next regulatory control period. PB noted Ergon Energy was unable to provide detailed information at either a project or program level justifying the $2 million per annum expenditure for the next regulatory control period.[490]

PB concluded that the $10 million forecast capex for the change program represented an anticipated pool of funds that may or may not be needed. PB considered that no new information had been provided which justified the underlying prudence and efficiency of the change program, and recommended the removal of the proposed expenditure from the capex forecast for the next regulatory control period.[491]

AER considerations

The AER reviewed Ergon Energy's revised regulatory proposal in relation to the change program, and sought advice from PB as to the prudence and efficiency of the expenditures proposed.

The AER notes that Ergon Energy clarified the scope of the change program as being non–ICT projects aimed at supporting transformational cultural change across the business. Ergon Energy provided examples of the types of projects which have formed part of the change program in the past,[492] and provided two business cases relating to specific projects. However, the AER notes that Ergon Energy has not provided detailed information at either a project or program level to justify the expenditure proposed for the next regulatory control period.[493]

Noting the advice of PB and the lack of specific information provided by Ergon Energy as to the scope of the change program, the AER considers that the change program effectively represents a pool of funds that may or may not be required in the next regulatory control period. On this basis, the AER considers that neither the prudence nor efficiency of the proposed capex for the change program has been demonstrated by Ergon Energy. The AER considers that all forecast capex associated with the change program should be removed from Ergon Energy's allowed capex for the next regulatory control period.

The AER requested Ergon Energy model the impact of the AER's decision on non–system capex for the change program. Ergon Energy advised that the adjustment to forecast non–system capex is a reduction of $14 million ($2009–10).[494]

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489 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 58.
490 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 58.
491 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 58–59.
492 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 128–129.
493 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 58.
494 Ergon Energy, response to modelling request, 22 April 2010.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast non–system capex for the change program reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's proposed non–system capex by $14 million ($2009–10) 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.

7.4.5.6 Overheads (ICT services)

AER draft decision

The AER concluded that with the exception of the data centre reconfiguration project, Ergon Energy's proposed ICT overheads costs for new capability projects was not supported by analysis which demonstrated the prudence and efficiency of proposed expenditures. The AER reduced Ergon Energy's proposed capex by $39 million and proposed opex by $6 million ($2009–10) to reflect the reduction in proposed overheads across both the capex and opex forecasts.[495]

Revised regulatory proposal

Ergon Energy noted that its regulatory proposal included SPARQ charges that were based on four new areas of ICT capability.[496] Ergon Energy noted the AER's conclusion that the majority of ICT projects were not supported by analysis that demonstrated prudence or efficiency, with the exception of the reconfiguration of the data centres.[497]

Ergon Energy submitted high level business cases for each of its major projects, which it stated lead to the next steps in its internal governance process.[498]

Distribution management system

Ergon Energy stated that the proposed DMS will allow it to connect embedded renewable generation to its network in the future and that it will provide significant other benefits, including enhanced operating efficiency, improved quality of supply and improved safety outcomes.[499]

Ergon Energy acknowledged that the timing and nature of the proposed DMS was still uncertain and it was therefore still building its final business case. Ergon Energy provided a high level business case with its revised regulatory proposal.[500] Ergon

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495 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 121, 165.
496 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 133.
497 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 133.
498 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 133.
499 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 133.
500 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 134.

Energy included costs of $22.8 million in its revised proposal to implement the proposed DMS.[501]

Field force automation

Ergon Energy stated that field force automation (FFA) would deliver a number of benefits, including reduced travel costs and improved data, customer service and travel safety. Ergon Energy also stated that FFA is a key part of its strategy for the future and so it has been retained as part of its capex forecast.[502]

Ergon Energy indicated that initial project outlays for FFA would be $35 million. However, Ergon Energy expected benefits to offset those costs; it included only $19 million for FFA in its regulatory proposal.[503]

New ICT infrastructure

Ergon Energy stated that taking advantage of new ICT products and capabilities as they are released results in a variety of benefits, ranging from efficiency improvements and competitive advantages through to solutions that facilitate business capability.[504] Ergon Energy stated that examples of technologies currently being considered include unified communications and identity and access management (IAM) and provided business cases for both. Ergon Energy also stated that as ICT technologies evolve relatively quickly, it was not yet clear which other technologies will emerge in the later years of the next regulatory control period.[505]

Ergon Energy has retained $1 million per year in its forecast capex in order to facilitate the investigation and implementation of new strategic ICT technologies where significant business benefit can be demonstrated.[506]

Consultant review

PB reviewed Ergon Energy's revised proposal for ICT expenditure, which included new business cases and accompanying documentation for DMS, FFA and new ICT infrastructure.[507]

Distribution management system

PB noted that the DMS business case outlined the scope, financial cost-benefits, risks, and dependencies of the project and identified two other alternatives to the project of 'do nothing' and 'deferral'.[508]

PB considered that the proposed investment would enable Ergon Energy to better provide decision and response capabilities in outage and reliability management and result in avoided costs. PB noted that a spreadsheet model provided to justify the prudence and efficiency of the expenditure indicated an overall NPV of implementing the DMS option of $24 million ($2009–10). PB performed a sensitivity analysis of the

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501 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 134–135.
502 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 134.
503 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 134.
504 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 135.
505 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 135.
506 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 135.
507 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 53.
508 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 54.

NPV results and confirmed that they remained positive under significantly more conservative assumptions of the benefits from the project.[509]

Based on its assessment of Ergon Energy's revised regulatory proposal, PB recommended approval of capex for the DMS project.

Field Force Automation

PB noted that the material provided by Ergon Energy to justify its FFA project included a business case that outlined the objectives, scope and financial cost-benefit analysis of the project.[510]

PB noted that the business case indicated that the project was expected to generate an NPV of approximately $20 million and that this was due mainly [redacted].[511]

PB performed a sensitivity analysis of the NPV results and confirmed that the project remained commercially viable under significantly more conservative assumptions regarding the total labour savings expected from the project.[512]

Based on its review, PB was satisfied with the need and net benefits of the project and recommended approval of the expenditure.[513]

New ICT infrastructure

PB noted that while two projects were assessed in the business case for new ICT infrastructure, it was implied that they were illustrative only.[514]

Despite the NPV positive findings in relation to the two projects, PB considered that the business case for this expenditure was neither focussed or project specific and that justification for an improvement in strategic technology appeared to be generic.[515] PB considered that justification for expenditure should be project specific and considered on a case-by-case basis to ensure that funds are located to their most efficient uses. On this basis, PB did not recommend approval of this expenditure.[516]

Conclusion

Based on the findings outlined above, PB recommended that only the new capability ICT projects for DMS and FFA be approved.[517]

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509 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 54.
510 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 54.
511 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 55.
512 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 55.
513 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 55.
514 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 55.
515 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 55.
516 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 55.
517 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 56.

PB noted that the recommended expenditure will be capitalised within SPARQ and passed through to Ergon Energy as a service charge. To calculate the reduction in the service charge associated with the SPARQ capex, PB used the 2008–09 SPARQ service charge as the base year costs and assumed the increase in the ICT overhead during the next regulatory control period is predominantly driven by the 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.[518] The results are presented in table 7.20.

Table 7.20: PB recommended reduction in Ergon Energy's ICT indirect costs expenditure – SPARQ ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ICT indirect costs	70.9	82.6	92.7	95.7	92.7	434.6
ICT baseline costs ($2009–10)	61.0	61.0	61.0	61.0	61.0	305.2
Increase in ICT ($m)	9.8	21.6	31.7	34.7	31.6	129.4
% reduction in SPARQ capex recommended by PB	–1.3	–1.9	–2.0	–2.1	–2.9	–1.9
Proportional reduction in ICT indirect costs	–0.1	–0.4	–0.6	–0.7	–0.9	–2.8
Reduction in capex indirect costs	–0.08	–0.31	–0.46	–0.54	–0.69	–2.16
Reduction in opex indirect costs	–0.02	–0.09	–0.14	–0.16	–0.21	–0.64
PB recommendation	70.8	82.2	92.1	95.0	91.8	431.8

Source: PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 36.

AER considerations

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 approach to reviewing SPARQ's ICT capex provides an appropriate method of determining the prudence and efficiency of SPARQ's service charges to Ergon Energy.

The AER reviewed the material provided by Ergon Energy to support its revised proposal in relation to ICT overhead expenditure. The AER notes that Ergon Energy provided new business cases and accompanying documentation to support three new capability ICT projects not approved in the draft decision.

The new business cases provided by Ergon Energy for its DMS and FFA projects included the objectives, scope and financial cost-benefit analyses for the projects and identified project options, including, 'do nothing' and 'deferral' options.

The AER notes that PB found the business cases for the DMS and FFA projects are NPV positive, suggesting that the new capability projects will be largely self-funding. The AER considers that the sensitivity analysis conducted by PB for both of these

518 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 56.

projects clearly demonstrates that they are likely to be justified even if the actual costs and benefits are less favourable than assumed in the base case projections.[519]

Given Ergon Energy provided sound business cases for the DMS and FFA new capability ICT projects, the AER accepts PB's recommendation to approve the increase in Ergon Energy's ICT service charges that are associated with expenditure for these projects.[520]

The AER considers that Ergon Energy's business case for new ICT infrastructure is not as robust as the business cases for the other two projects under consideration. As noted by PB, the business case did not appear to be based on definite initiatives. Rather, it appeared that the two projects assessed in the business case were chosen for illustrative purposes only. The AER agrees with PB that proposed expenditure should be project specific and considered on a case-by-case basis to ensure that funds are used efficiently.[521] On this basis, the AER does not consider that a higher ICT service charge associated with the proposed new ICT infrastructure is justified.

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 $1 million ($2009–10).[522]

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised 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 $1 million ($2009–10) 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.

7.5 AER conclusion

7.5.1 Energex

The AER has reviewed Energex's proposed forecast capex allowance and, for the reasons set out in this chapter, the AER is not satisfied that Energex's 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.

As the AER is not satisfied that the capex allowance proposed by Energex 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 required to provide an estimate of the capex for Energex over the next

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519 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 55.
520 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 56.
521 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 55–56.
522 Ergon Energy, response to modelling request, 22 April 2010.

regulatory control period which it is satisfied reasonably reflects the capex criteria, taking into account the capex factors.

Following its review of Energex's revised capex proposal, the AER has made the following adjustments:

- $273 million reduction to growth capex to reflect a realistic expectation of demand
- $32 million reduction to non–system capex to reflect the removal of unsupported contingencies in property project cost estimates
- $2 million reduction to indirect costs associated with ICT services which do not reflect efficient costs
- $250 million reduction to total capex to reflect the application of amended input cost escalators as determined in appendix F.

The AER considers these adjustments to be the minimum necessary to ensure Energex's capex forecast meets the capex criteria. Allowing for the adjustments listed above, the AER's estimate of forecast capex for Energex is $5783 million, as set out in table 7.21. The AER is satisfied that this estimate reasonably reflects the capex criteria, taking into account the capex factors.

Table 7.21: AER conclusion on Energex's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex revised proposed capex	1232.1	1275.1	1265.0	1238.5	1275.7	6286.3
Adjustment to growth capex	–36.5	–43.3	–55.1	–63.4	–74.6	–273.0
Adjustment to non–system capex	–38.0	8.7	–2.5	–	–	–31.8
Adjustment to indirect costs	–0.1	–0.3	–0.3	–0.3	–0.5	–1.6
Re-inclusion of indirect costs that were included in growth capex and non–system capex deductions	12.2	5.6	10.4	11.5	13.8	53.6
Adjustment to cost escalators	–43.8	–74.1	–59.6	–42.7	–30.3	–250.5
AER capex allowance	1125.8	1171.8	1157.7	1143.5	1184.1	5783.0

Notes: Totals may not add due to rounding.
The indirect costs included in deductions to growth and non–system capex should not 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.

7.5.2 Ergon Energy

The AER has reviewed Ergon Energy's proposed forecast capex allowance and, for the reasons set out in this chapter, the AER is not satisfied that Ergon Energy's 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.

As the AER is not satisfied that the capex allowance proposed by Ergon Energy 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 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.

Following its review of Ergon Energy's revised capex proposal, the AER has made the following adjustments:

- $500 million reduction to CIA capex to reflect a revised scope for sub–transmission network augmentation and a realistic expectation of demand
- $402 million reduction to CICW capex to reflect a revised approach to estimating customer initiated capital works expenditure
- $119 million reduction to asset replacement capex to reflect a business as usual approach to forecasting expenditure in this category
- $26 million reduction to reliability and quality improvement capex to exclude expenditure associated with the feeder improvement program and reflect a revised forecasting methodology for this expenditure category
- $121 million reduction to non–system capex to exclude unsupported expenditure on major property projects and the ICT change program
- $5 million reduction to other system capex to reflect the removal of capex costs associated with trials of smart meters
- $1 million reduction to indirect costs associated with ICT services which do not reflect efficient costs
- $278 million reduction to total capex to reflect the application of amended input cost escalators as determined in appendix F.

The AER considers these adjustments to be the minimum necessary to ensure Ergon Energy's capex forecast meets the capex criteria. Allowing for the adjustments listed above, the AER's estimate of forecast capex for Ergon Energy is $4989 million, as set out in table 7.22. The AER is satisfied that this estimate reasonably reflects the capex criteria, taking into account the capex factors.

Table 7.22: AER conclusion on Ergon Energy's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy revised proposed capex	1123.2	1222.1	1232.0	1293.5	1403.4	6274.1
Adjustment to CIA capex	–19.6	–102.1	–114.9	–127.3	–135.6	–499.6
Adjustment to CICW capex	–73.9	–103.2	–56.5	–68.4	–100.4	–402.3
Adjustment to asset replacement capex	–9.9	–19.4	–30.9	–30.0	–28.6	–118.8
Adjustment to reliability and quality improvement capex	–0.7	–2.6	–5.2	–7.9	–9.5	–25.9
Adjustment to non–system capex	–17.9	–27.8	–32.8	–17.8	–24.7	–121.0
Adjustment to other system capex (smart meters)	–5.3	–0.2	–	–	–	–5.5
Adjustment to shared costs	–0.0	–0.1	–0.2	–0.4	–0.6	–1.3
Re-inclusion of shared costs that were included in growth, asset replacement, reliability, other system and non–system capex deductions	18.6	51.1	29.4	33.9	34.6	167.6
Adjustment to cost escalators	–36.7	–70.2	–63.8	–57.8	–50.0	–278.4
AER capex allowance	977.8	947.7	957.1	1017.9	1088.5	4988.9

Notes: Totals may not add due to rounding.
The shared costs included in deductions one to six above should not be removed from Ergon Energy's capex allowance. This is because, with the exception of an adjustment for ICT services, the AER has not proposed any adjustments to Ergon Energy's shared costs.

7.6 AER decision

In accordance with clause 6.12.1(3)(ii) of the NER the AER does not accept Energex's forecast capex for the next regulatory control period. The AER is not satisfied that Energex's forecast capex, taking into account the capex factors, reasonably reflects the capex criteria in clause 6.5.7 of the NER.

The AER's reasons for this decision are set out in section 7.4 of this decision.

The AER's estimate of the total capex required by Energex in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, is set out in table 7.21 of this decision.

In accordance with clause 6.12.1(3)(ii) of the NER the AER does not accept Ergon Energy's forecast capex for the next regulatory control period. The AER is not satisfied that Ergon Energy's forecast capex, taking into account the capex factors, reasonably reflects the capex criteria in clause 6.5.7 of the NER.

The AER's reasons for this decision are set out in section 7.4 of this decision.

The AER's estimate of the total capex required by Ergon Energy in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, set out in table 7.22 of this decision.

8 Forecast operating expenditure

This chapter sets out the AER's consideration of issues raised in response to the draft decision on forecast opex for the Qld DNSPs. It also sets out the AER's conclusion on the Qld DNSPs' forecast opex for the next regulatory control period.

The opex forecasts in the Qld DNSPs' revised regulatory proposals are based on their requirements for the provision of standard control services during the next regulatory control period. The AER has assessed the proposed opex against the requirements of chapter 6 of the NER.

8.1 AER draft decision

Energex

The AER was satisfied that Energex's methodology for establishing its forecast opex was sound. The AER was not satisfied that Energex's forecast total opex for the next regulatory control period of $1843 million ($2009–10) reasonably reflected the opex criteria, including the opex objectives. In coming to this view the AER had regard to the opex factors. In establishing an opex allowance the AER made the following specific adjustments:[523]

- $2.2 million reduction to the demand and energy data capture and analysis program
- $11 million reduction to other support costs
- $2.2 million reduction to information, communications and telecommunications (ICT) overheads
- $19 million reduction to debt raising costs
- $87 million reduction to equity raising costs
- $15 million reduction to self insurance costs
- $140 million reduction to total opex to reflect the impact of revised input cost escalators
- $21 million reinclusion of overheads.

Based on its analysis of Energex's regulatory proposal, the advice of consultants and other information, the AER applied a reduction of $256 million (14 per cent) to Energex's proposed opex forecast. This resulted in a revised opex forecast of $1586 million ($2009–10) for the next regulatory control period. This reduction was mostly a consequence of expected reductions in input costs and other adjustments to non–controllable opex claims. The AER considered this reduction was the minimum

[523] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 192–193.

adjustment necessary to ensure Energex's proposed opex forecast met the opex objectives and criteria.[524]

The AER's draft conclusion on Energex's opex by category is in table 8.1.

Table 8.1: AER draft conclusion on Energex's total opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex's controllable opex forecast	324.5	360.8	340.4	351.6	349.2	1695.7
Self insurance costs	2.8	2.9	3.1	3.2	3.0	15.1
Debt raising costs	7.2	8.1	9.0	9.9	10.7	44.8
Equity raising costs	20.6	19.8	18.8	15.7	12.6	87.4
Energex's total opex	355.1	360.9	371.3	380.4	375.5	1843.1
AER's controllable opex (including input cost escalators)	303.6	303.7	308.7	315.4	308.7	1540.1
Self insurance costs	0.0	0.0	0.0	0.0	0.0	0.04
Debt raising costs	4.2	4.6	5.1	5.5	6.0	25.3
Equity raising costs	–	–	–	–	–	–
Reinclusion of overheads removed in AER controllable opex	5.4	3.8	4.2	3.5	4.0	20.9
AER total opex	313.2	312.2	318.0	324.4	318.7	1586.3

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 193.

Ergon Energy

The AER was mostly satisfied that Ergon Energy's methodology for establishing its forecast opex was sound. The AER considered Ergon Energy's forecast total opex of $1993 million ($2009–10) and was not satisfied that it reasonably reflected the opex criteria, including the opex objectives. In coming to this view the AER had regard to the opex factors. In establishing an opex allowance the AER made the following adjustments:[525]

- $33 million reduction to preventative maintenance
- $14 million reduction to corrective maintenance
- $7 million reduction to forced maintenance

524 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 193.
525 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 194.

- $53 million reduction to vegetation management
- $84 million reduction to other opex
- $6.4 million reduction to ICT overheads
- $21 million reduction to self insurance
- $72 million reduction to debt and equity raising costs
- $264 million reduction to reflect the impact of revised input cost escalators
- $75 million re-inclusion of overheads.

Based on its analysis of Ergon Energy's regulatory proposal, the advice of consultants and other information, the AER applied a total reduction of $479 million (24 per cent) to Ergon Energy's opex forecast. This resulted in a revised forecast opex allowance of $1514 million ($2009–10) for the next regulatory control period. The AER considered this reduction was the minimum adjustment necessary to ensure Ergon Energy's proposed opex forecast met the opex criteria.[526]

The AER's draft conclusion on Ergon Energy's opex by category is in table 8.2.

Table 8.2: AER draft conclusion on Ergon Energy's total opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy controllable opex forecast	365.9	377.3	381.2	382.3	370.2	1876.9
Self insurance costs	4.2	4.2	4.3	4.4	4.5	21.5
Debt and equity raising costs	11.9	16.3	22.0	22.8	21.1	94.1
Ergon Energy total opex	382.0	397.8	407.5	409.5	395.8	1992.6
AER controllable opex (including input cost escalation and reinstated shared costs)	316.7	315.2	300.4	288.9	271.0	1492.1
Self insurance costs	0.0	0.0	0.0	0.0	0.0	0.016
Equity raising costs	–	–	–	–	–	–
Debt raising costs	3.8	4.0	4.4	4.7	5.1	22.0
AER total opex	320.5	319.2	304.8	293.6	276.1	1514.2

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 195.

[526] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 192–193.

8.2 Revised regulatory proposals

Energex

Energex implemented the draft decision in respect of forecast opex except those aspects related to:[527]

- ICT services expenditure
- self insurance
- cost escalators
- dividend payout ratio.

In addition, Energex included a forecast for feed–in tariff costs, in relation to the solar bonus scheme operating in Queensland.[528]

Energex's forecast opex allowance as presented in its revised regulatory proposal for the next regulatory control period was $1617 million ($2009–10). These opex forecasts, shown in table 8.3, were derived using the AER's cost escalators as outlined in the draft decision.

Table 8.3: Energex's revised regulatory proposal opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Network operating costs	24.3	24.9	25.3	25.7	25.9	126.1
Inspection	18.2	19.2	20.4	20.8	22.0	100.5
Planned maintenance	62.6	60.2	61.1	61.6	61.8	307.3
Corrective repair	38.0	38.2	38.0	37.9	37.6	189.6
Vegetation	72.6	72.8	73.2	72.8	72.0	363.5
Emergency response/storms	8.1	8.3	8.3	8.4	8.4	41.5
Meter reading	13.8	14.1	14.5	14.9	15.4	72.7
Customer services	19.9	20.1	20.3	20.6	20.8	101.7
DSM initiatives	21.1	21.6	23.2	28.0	20.5	114.4
Levies	8.5	8.8	9.2	9.5	9.8	45.8
Other support costs	16.9	16.5	16.9	16.3	15.7	82.3
Solar bonus scheme administration costs	0.8	0.8	0.8	0.8	0.8	3.9
Energex total controllable opex	304.8	305.4	311.3	317.0	310.6	1549.1
Self insurance costs	1.2	1.2	1.3	1.3	1.3	6.3
Debt raising costs	4.1	4.6	5.1	5.6	6.1	25.6
Feed–in tariffs	4.6	5.9	7.1	8.4	9.6	35.6
Energex total opex	314.8	317.2	324.8	332.3	327.6	1616.7

Source: Energex, *Revised regulatory proposal*, January 2010, RIN proforma 2.2.2 and p. 31.
Note: Totals may not add due to rounding.

527 Energex, *Revised regulatory proposal*, January 2010, p. 22.
528 Energex, *Revised regulatory proposal*, January 2010, p. 26.

Energex subsequently submitted a revised approach to cost escalation, which increased its total proposed opex allowance to $1670 million ($2009–10).[529]

Ergon Energy

Ergon Energy did not accept the draft decision and substituted an opex forecast of $1894 million ($2009–10) that included:[530]

- revised labour cost escalators
- revised maintenance opex
- reinstated demand management, customer service and meter reading opex
- new opex relating to guaranteed service levels (GSL) reporting requirements
- revised self insurance opex
- reinstated shared costs (overheads).

In addition, Ergon Energy included a forecast for feed–in tariffs and provided revised estimates for its GSL payment obligations in response to the QCA decision on GSL obligations.[531]

Ergon Energy's revised regulatory proposal opex forecast is shown in table 8.4.

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[529] Energex, *Submission on the draft determination for the period July 2010–June 2015,* February 2010 and Energex, email response, AER.RP.4, 5 March 2010, Opex Model, confidential.

[530] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 176.

[531] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 169–170.

Table 8.4: Ergon Energy revised regulatory proposal opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Network operating costs	26.2	26.3	26.6	27.1	27.3	133.4
Preventative maintenance	106.7	119.1	117.7	119.1	119.4	581.9
Corrective maintenance	119.0	119.0	119.5	114.5	102.3	574.3
Forced maintenance	41.4	41.6	41.7	41.6	40.9	207.2
Meter reading costs	11.7	11.8	12.0	12.3	12.4	60.3
Customer service costs	19.9	20.2	20.3	20.7	20.7	101.8
Other operating costs	44.1	45.6	46.6	48.5	50.5	235.3
Total network and other opex	369.0	383.6	384.4	383.8	373.5	1894.1
Debt raising costs	3.8	4.2	4.7	5.2	5.7	23.7
Total opex[a]	372.7	387.8	389.2	388.8	379.3	1917.8

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, PTRM.
Note: Totals may not add due to rounding.
(a) Ergon Energy's total opex of $1928.0 million reported in its post–tax revenue model (PTRM) includes an amount of $10.2 million for accelerated depreciation of assets destroyed by Cyclone Larry. This amount is not included in the total opex shown in this table.

8.3 Submissions

Self insurance

Energex submitted atypical storm events and retail failure events should be classified as specific pass through events. Further, it stated materiality thresholds for general pass through events should be increased to 2 per cent of opex and that self insurance reporting arrangements were too onerous.[532]

Benchmarking

The Energy Users Association of Australia (EUAA) considered the AER is rewarding inefficient network businesses with large expenditure increases, resulting in energy users paying for inefficient costs. It requested the AER to honour commitments regarding working with energy users in promoting the implementation of benchmarks.[533]

Cement Australia considered the AER should apply its statutory role to use benchmarking to help establish an efficient level of network costs.[534]

[532] Energex, *Submission on draft determination,* February 2010, pp. 26–28.
[533] EUAA, letter to the AER, 4 January 2010, pp. 1–2.
[534] Cement Australia, *AER review of electricity distribution prices in Queensland*, 16 February 2010.

EnergyAustralia supported the AER's use of benchmarking to test the reasonableness of DNSPs' detailed expenditure proposals. It considered the AER's current method to benchmarking opex does not lead to a sufficient test of the reasonableness of a DNSP's proposal.[535]

8.4 Issues and AER considerations

8.4.1 Energex

8.4.1.1 Shared costs – ICT systems

AER draft decision

The AER was not satisfied that the proposed ICT overheads reflected the opex criteria, including the opex objectives, concluding that a reduction of $2.2 million to ICT overheads was required in order for the ICT costs to meet the opex criteria. This was due to a lack of evidence supporting additional new capability expenditure, as outlined in appendix F of the draft decision.[536]

Revised regulatory proposal

Energex did not accept the reductions made by the AER in relation to ICT–related overheads and provided business case documentation in support of its original proposal.[537]

Consultant review

PB conducted a detailed review of Energex's revised ICT expenditure, which included ten projects aimed at providing new ICT capability. These projects include both capex and opex cost elements and PB's review is described in section 7.4.3.5 of this decision. PB noted that Energex provided business cases for only seven of these projects, which accounted for approximately $8.4 million (or 29 per cent) of total new ICT capability expenditure proposed by Energex.

Where it was able to review business case details PB considered that benefits associated with the projects included better planning and design and more effective network modelling.[538] However, where no new information had been provided to justify the expenditure (approximately 17 per cent of the total new ICT capability expenditure), PB was not satisfied that Energex had demonstrated the need or reasonableness of those projects and recommended reducing the ICT opex.[539]

PB noted that the recommended expenditure will be capitalised within SPARQ and passed through to Energex as a service charge. To calculate the reduction in the service charge associated with the SPARQ capex, PB used the 2008–09 SPARQ service charge as the base year costs and assumed the increase in the ICT overhead during the next regulatory control period is predominantly driven by the SPARQ capex. PB then applied a reduction to the increase in the SPARQ service charge was

535 EnergyAustralia, *Submission on AER draft determinations,* February 2010, pp. 2–3, 5.
536 AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, pp. 494–498.
537 Energex, *Revised regulatory proposal*, January 2010, p. 27.
538 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 9.
539 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 10.

proportional to the reduction recommended for the SPARQ ICT capex. To derive its recommended reduction in opex for ICT indirect costs, PB allocated the total reduction in ICT service charge to capex and opex in accordance with Energex's approved cost allocation method (CAM). PB recommended an adjustment to the opex component of the ICT service charge of $0.8 million ($2009–10).[540]

AER considerations

The AER notes that the majority of Energex's expenditure in this category is delivered under its arrangement with SPARQ, for which Energex is charged a service fee. These service fees are treated as shared costs by Energex, which are discussed in more detail in section 7.4.3.5 of this decision. The AER's review of the SPARQ service fee resulted in a reduction to Energex's proposed costs based on a lack of information to justify three of the proposed ICT projects. The AER notes Energex allocates shared costs in accordance with its approved CAM, which results in approximately 23 per cent of ICT service fees being allocated to opex. Energex advised the proportionate impact of the AER's total reduction to SPARQ ICT capex is a $0.7 million ($2009–10) reduction to its proposed ICT overhead opex.[541]

AER conclusion

For the reasons discussed in section 7.4.3.5, and as a result of the AER's consideration of Energex's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's forecast ICT overheads opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Energex's proposed allocation of shared ICT costs by $0.7 million ($2008–09) 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.

8.4.1.2 Feed–in tariff — Solar bonus scheme

AER draft decision

The AER considered that feed–in tariff payments could be provided for by means of an opex allowance and a specific nominated pass through event.[542] However, the AER considered that the following definition of a feed–in tariff event should apply:[543]

> A **feed–in tariff event** occurs if, at the end of a regulatory year of a regulatory control period, the amount of feed–in tariff payments made by a Qld DNSP for that regulatory year is higher or lower than the amount of feed–in tariff payments (if any) that is provided for in that Qld DNSP's annual revenue requirement for that regulatory year.
>
> Relevant feed–in tariff payments under this pass through mechanism are those paid through the operation of the *Electricity Act 1994 (Qld)*, and any amendments to this Act.

540 PB, *Review of Energex's revised regulatory proposal*, April 2010, pp. 10–11.
541 Energex, response to modelling request, 9 April 2010, confidential.
542 Energex, *Regulatory proposal*, July 2009, pp. 284–285.
543 AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, p. 340.

This definition provides that a feed–in tariff event may be considered as a specific nominated pass through event when, at the end of a regulatory year, the amount of feed–in tariff payments made is higher or lower than the amount provided for in opex.

Revised regulatory proposal

Energex submitted a forecast of feed–in tariff payments and solar bonus scheme administration costs as shown in table 8.5.

Table 8.5: Energex's forecast opex for solar bonus scheme costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Tariff payments	4.6	5.9	7.1	8.4	9.6	35.6
Administration costs	0.8	0.8	0.8	0.8	0.8	3.9
Total costs	5.4	6.7	7.9	9.2	10.4	39.5

Source: Energex, *Revised regulatory proposal*, January 2010, p. 26.
Note: Totals may not add due to rounding.

Energex stated that these forecasts are based on current year to date payments, at the current rate of 44 cents per kWh. In addition, Energex estimated that eight full–time equivalent employees will be required to process and administer the scheme on an ongoing basis.[544] This estimate is reflected in Energex's forecast of $3.9 million for solar bonus scheme administration costs.

Consultant review

PB examined the feed–in tariff payment and administration forecasts. PB noted that Energex had used the following assumptions to derive its feed–in tariff forecasts:[545]

- an estimate of 15 600 units installed as of July 2010
- the number of new solar photovoltaic (PV) installations per month from July 2010 is assumed to be 400 per month (compared to the anticipated peak rate of 1400 per month in late 2009)
- Energex's analysis from the existing 14 000 solar PV installations in south east Queensland (as at January 2010) shows an average feed–in of 49 kWh of energy per month, which at a rate of 44 cents/kWh equals $21.50 per system, per month.

PB confirmed that Energex applied a reasonable and transparent forecasting methodology for feed–in tariff payments for residential solar PV installations. PB found the forecasts were based on reasonable input assumptions, in particular an anticipated 9600 installations in each year of the next regulatory control period.[546]

[544] Energex, *Revised regulatory proposal*, January 2010, p. 27.
[545] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 21.
[546] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 21.

PB considered that the revised opex allowance for feed–in tariff payments was prudent and efficient given the forecasting methodology used.[547]

However, PB did not consider that it was necessary to employ eight full–time equivalent staff to undertake the administration of the solar bonus scheme. PB stated the functional stages set out by Energex indicate that the activities – including agreement processing and service ordering – are quite mechanised and could be managed with appropriate software. For this reason PB considered that the volume of solar PV installations was not a strong cost driver. PB considered the administrative role could be undertaken by two full–time staff. PB made this recommendation on the basis that, by July 2010, Energex will have already processed around 40 per cent of the total installations expected out to June 2015.[548]

AER considerations

The AER reviewed Energex's feed–in tariff forecasting methodology and considers that the assumptions that underlie the model are conservative and the methodology used by Energex is robust. The AER notes that there is a level of uncertainty around the final expenditure associated with feed–in tariff payments. However, the under and over recovery of tariff payments will be subject to a positive and negative pass through each regulatory year, as discussed in chapter 15 of this decision.

The AER notes Energex proposed employing eight full–time employees to administer the solar bonus scheme. This includes four full–time permanent staff plus another four full–time staff who would be employed on fixed–term contracts and appointed when volumes or trends dictate that full–time employees are required to achieve on time performance.[549]

The AER considers that the level and magnitude of work required should not entail the engagement of eight full–time employees. The AER notes that the solar bonus scheme has been operational since 1 July 2008. The AER considers that Energex would therefore already have staff conducting administrative duties in relation to the scheme, and an additional eight staff seems high.

The AER also notes the cost per employee proposed by Energex. For the administrative processes for which these staff would be employed, the AER considers that these wage levels are excessive.[550] PB described the tasks as quite mechanised and given the nature of these tasks, the AER considers that a wage rate that reflects the wage rates for administrative staff within the Queensland or Australian government is more appropriate.

The AER also notes that neither ETSA Utilities nor Ergon Energy included administration costs for their respective solar bonus or feed–in tariff schemes. The AER considers that Energex has overstated its likely administrative costs. A reduction in the number of full–time staff, and a reduction in the cost per employee, is required

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547 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 21.
548 PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 21.
549 Energex, email response, AER.EX.RP.1.2, part 2, 16 February 2010, confidential.
550 The AER notes that Energex separately accounts for staffing on costs, and the forecast administrative costs represent wage costs only.

to bring Energex's forecast opex for solar bonus scheme administration costs into line with comparable businesses.

The AER requested Energex to model the impact of the AER's decision on solar bonus scheme administration costs. Energex advised that the adjustment to its solar bonus scheme administration costs is a reduction of $3.3 million ($2009–10).[551]

AER conclusion

For the reasons discussed, and as a result of the AER's analysis of Energex's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Energex's forecast of solar bonus scheme opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Energex's proposed solar bonus scheme administration costs by $3.3 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.

The AER's decision in relation to Energex's solar bonus scheme opex forecasts are shown in table 8.6.

Table 8.6: AER conclusion on solar bonus scheme opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Feed–in tariff payments	4.6	5.9	7.1	8.4	9.6	35.6
Solar bonus scheme administration costs	0.1	0.1	0.1	0.1	0.1	0.6
Total solar bonus scheme opex	4.8	6.0	7.2	8.5	9.7	36.2

Note: Totals may not add due to rounding.

8.4.2 Ergon Energy

8.4.2.1 Preventative maintenance

Inspection cycle for ground based poles

AER draft decision

The AER did not accept Ergon Energy's proposed opex based on a four year inspection cycle for its ground based poles. The AER stated that the inspection cycle should be increased to 4.5 years on the basis the poles were in excellent condition.[552] The longer inspection cycle resulted in a reduction of $17 million ($2009–10) to the forecast controllable opex for the next regulatory control period.[553]

551 Energex, response to modelling request, 9 April 2010, confidential.
552 AER, *Draft Decision*, *Queensland draft distribution determination*, November 2009, pp. 666–667.
553 AER, *Draft Decision*, *Queensland draft distribution determination*, November 2009, pp. 667–668.

Revised regulatory proposal

Ergon Energy argued that its original preventative maintenance forecast that allows for 4 year pole inspection cycles should be maintained.[554] It engaged Huegin Consulting (Huegin) to review the draft decision.[555] Huegin advised:[556]

- neither the AER nor PB had sufficient information to make an informed decision to increase the current inspection periodicity
- comparison with the Energex network and their five year regime is inappropriate
- increasing the pole inspection periodicity to 4.5 years would have a detrimental effect upon the pole failure rate and therefore the business risk
- an increase in pole inspection periodicity would have a detrimental effect upon corrective maintenance opex.

Ergon Energy rejected the draft decision to extend the periodicity of pole inspections by 6 months to 4.5 years, on the basis that:

- it does not know the P–F (potential for failure) curve for its pole population, and such information is essential
- its current performance against the mandated performance standard does not justify an extension to the pole inspection periodicity
- the underlying hazard rate for the pole population increases exponentially with age and hence increasing the pole inspection periodicity will increase the failure rate
- extending the pole inspection periodicity to 4.5 years will mean that not all poles will be inspected within the mandatory 5 year period.

Consultant review

PB stated that Ergon Energy's revised regulatory proposal provided no new material to substantiate its position that a pole inspection cycle of 4 years should be maintained. PB provided clarification in response to the key criticisms raised by Ergon Energy.[557]

Ergon Energy does not know the P-F curve for its pole population / There is insufficient information to justify an extension to the pole inspection periodicity to 4.5 years

PB recognised that Ergon Energy was moving towards a risk based maintenance strategy and acknowledged that Ergon Energy lacked some of the information required for the new maintenance strategy. However, PB stated that alternative

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554 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 151–155.

555 Huegin Consulting is a strategic management and advisory firm.

556 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 151–155, and attachment RP938c, Huegin Report, January 2010, p. 71.

557 PB, *Review of Ergon Energy's revised regulatory proposa*l, April 2010, p. 69–73.

information was available to Ergon Energy which could be relied upon for the purposes of making informed decisions on pole inspection activities.[558]

PB noted that Ergon Energy was collecting historical data on the performance of its assets, including records of unassisted failure results. PB considered this constituted sufficient information on which asset management and maintenance based decisions could be based. PB stated that running a pole inspection cycle dependent on unassisted pole failure rates was consistent with the minimum reliability standard within the *Code of Practice for Works*.[559] [560] PB also noted that Ergon Energy considered the data it had was sufficient to enable it to change from a 3 year inspection cycle to a 4 year cycle in 2006.

PB also noted that Ergon Energy would have collected two inspection cycles worth of data by the beginning of the next regulatory control period.[561] On this basis, PB considered that Ergon Energy had sufficient information to run a pole inspection cycle that was in accordance with its condition based management approach.[562]

Comparison with the Energex network and their five year regime is inappropriate

PB noted that the drivers of pole degradation and the environmental concerns relevant to Ergon Energy's wood pole population were not similar to those experienced by Energex, particularly in the context of the nine climatic variables referenced by Huegin. Based on these considerations, PB recommended a different inspection cycle to that employed by Energex.[563]

Increasing the pole inspection periodicity to 4.5 years would have a detrimental effect upon the pole failure rate / The underlying hazard rate for the pole population increases exponentially with age and hence increasing the pole inspection periodicity will increase the failure rate

PB disagreed with Huegin and considered that an extension of the pole periodicity rate to 4.5 years was consistent with how a prudent and efficient distribution network operator would operate in circumstances similar to Ergon Energy.[564]

PB stated that Ergon Energy had flexibility within its business processes to vary its inspection program so that higher risk poles could be inspected more often, while low risk poles could be inspected at periods of greater than 4.5 years. PB stated that a well coordinated maintenance program would ensure that all poles could be inspected in the designated time frames, notwithstanding the impact of environmental and weather related influences.[565]

PB also noted that other factors would deter the pole failure rate from increasing if the inspection cycle was extended by six months as Ergon Energy:

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558 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 70.

559 The *Code of Practice for Works* is published by the Queensland Electrical Safety Office and sets out best practice operating and maintenance guidelines for Queensland electricity entities.

560 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 70.

561 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 70.

562 PB noted the observation by Huegin that 37.4 per cent of poles do not have an exact date of construction. This would suggest that 62.6 per cent of poles do have a recorded asset age.

563 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 72.

564 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 71–72.

565 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 72.

- had an excellent history of wood pole reliability performance that exceeds the safety standards set by the *Code of Practice for Works*[566]

- used steel pole nails or stakes which decreased the pole failure rate by extending the pole life

- operated a comprehensive asset management program that assisted with deterring the failure rate of its poles.[567]

PB considered that given the excellent performance rating of its poles and the fact that Ergon Energy's poles are built from solid materials, there was unlikely to be severe failures occurring in the next regulatory control period. PB argued that extension of its pole inspection program was a key area where savings could be realised for the purposes of running a prudent and efficient distribution network.[568]

Increased pole inspection periodicity will have a detrimental effect upon corrective maintenance opex

PB disagreed with Huegin's findings and stated that there should not be any significant pressure on corrective and forced maintenance costs if the inspection cycle was extended by six months. PB noted:[569]

- When Ergon Energy increased its inspection cycle from three to four years in 2006, there was a significant fall in the unassisted pole failure rate. PB also noted that Ergon Energy's replacement rate did not significantly rise as a result of increasing its inspection cycle. This suggested that Ergon Energy's pole population was in excellent condition and was not at the stage of life cycle when maintenance costs are high and needed frequent inspections and monitoring.

- Ergon Energy's existing business procedures for inspecting, assessing, marking and maintaining poles were well above those required by the safety guidelines. This suggested that Ergon Energy had other repair and maintenance works programs in place that alleviated pressure associated with reducing the inspection activities on its poles. These other programs reduced the need for corrective and forced maintenance programs to take place.

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566 PB's November 2009 report noted that since March 2006 when Ergon Energy increased its inspection cycle from three to four years, the three year moving average of unassisted pole failures improved from about 99.993% to 99.997% as of August 2008. This constituted a 50 per cent reduction in annual failures from around 70 per annum per million poles to 30 million and this can be compared with the minimum target of 100 failures stipulated in the Qld Electrical Safety Office's *Code of Practice for Works*. PB noted that a marginal reduction in performance has been observed for the subsequent 6 month period to February 2009. PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 69.

567 PB stated that the replacement program leveraged off the Ergon Energy's *Defect Classification Manual*, which in turn was informed by Ergon Energy's corporate risk profile. Ergon Energy, *Revised regulatory proposal*, January 2010, p. 135.

568 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 71.

569 PB, *Review of Ergon Energy's revised regulatory proposal, April 2010,* p. 72.

AER considerations

Ergon Energy does not know the P-F curve for its pole population / There is insufficient information to justify an extension to the pole inspection periodicity

The AER accepts Ergon Energy's statement that it does not know the P–F curve for its pole population. However, the AER does not accept that such information is essential in determining the periodicity of pole inspections. This is because Ergon Energy has previously made such a decision without this information, when it increased the periodicity of its pole inspection cycle from 3 years to 4 years in 2006.

Further, the AER notes that at the commencement of the next regulatory control period Ergon Energy will have data on its pole population, collected in accordance with its *Asset Equipment Plan*, from two full inspection cycles undertaken since 2003. The data Ergon Energy should have available includes the unassisted failure rates of its poles, as well as data on durability rating, preservation type, inspection procedures, performance of the poles, fungal decay, and termite risk.

The AER notes PB considers that such data provides more relevant information than exact age or date of manufacture of poles, and can be used to determine inspection intervals.[570]

The AER considers that Ergon Energy has sufficient information on its pole population to implement an extension of inspection periodicity to 4.5 years.

Comparison with the Energex network and their five year regime is inappropriate

The AER notes that PB has clarified its comparison of Ergon Energy and Energex's pole inspection cycles, and in particular notes that differences in pole degradation and environment contributed to the recommendation that the pole inspection periodicity be increased to 4.5 years, rather than 5 years as used by Energex.

The AER considers that PB's comparison with Energex's network takes into account differences between the operating environments of the two DNSPs and the differences have contributed to the lower periodicity of inspection cycles recommended by PB for Ergon Energy.

Increasing the pole inspection periodicity to 4.5 years would have a detrimental effect upon the pole failure rate / The underlying hazard rate for the pole population increases exponentially with age and hence increasing the pole inspection periodicity will increase the failure rate

The AER notes that PB considered that Ergon Energy only had limited evidence to support its contention that the increased periodicity of pole inspections will increase the pole failure rate. PB stated that given the excellent performance rating of its poles and the fact that Ergon Energy's poles are built from solid materials, there was unlikely to be severe failures occurring in the next regulatory control period.

The AER notes Ergon Energy's pole performance ratings are below the minimum failure target stipulated in the *Code of Practice for Works*. The AER also notes Ergon Energy's current procedures for inspecting, assessing, marking and maintaining poles are above those required by safety guidelines. Given Ergon Energy's pole

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[570] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 70–71.

performance the AER considers that the impact on pole failure rates of an increased pole inspection cycle is likely to be minimal.

Extending the pole inspection periodicity to 4.5 years will mean that not all poles will be inspected within the mandatory 5 year period.
The AER considers that Ergon Energy has discretion to be flexible with its business operations to inspect poles based on the condition performance of the poles. Further, the AER considers that Ergon Energy has data that will enable it to make that assessment, collected in accordance with its *Asset Equipment Plan*. Such information could result in varied inspection cycles for different elements of the pole population. Poles that are newer or in a lower risk area for environmental factors could be inspected less frequently and older higher risk poles could be inspected more frequently.

The AER also notes the recommended 4.5 year inspection cycle includes a 6 month buffer for Ergon Energy to manage possible delays in inspections.

An increase in pole inspection periodicity would have a detrimental effect upon corrective maintenance opex
The AER notes PB considered this issue and did not consider Ergon Energy has provided evidence of a need to increase corrective maintenance expenditure. In particular, PB did not consider Ergon Energy has provided evidence to demonstrate that the 6 month extension to the pole inspection cycle will increase defect standards or impact decay rates such that there is a material increase in unassisted pole failures.

The AER notes that costs associated with corrective and forced maintenance activities arising from a change in the pole inspection cycle have been factored into Ergon Energy's opex modelling. When considered in conjunction with the forecast constant nailing rate for poles that has been used to develop the opex forecasts, the AER considers that an increase in corrective maintenance is not required in response to the extension of the pole inspection periodicity.

Summary

The AER considers that Ergon Energy has not demonstrated the efficiency of its forecast preventative opex in relation to the periodicity of pole inspection cycles. In particular, the AER considers that Ergon Energy has demonstrated that it has sufficient information on which to base such a decision, as it has previously increased the periodicity of the inspection cycles, and now should have even greater knowledge of its assets. Further, the information presented by Ergon Energy in relation to the likely detriment arising from increased inspection cycles has been subject to a detailed review by PB. This review has not provided sufficient evidence to accept Ergon Energy's claims.

The AER considers that the efficient opex allowance for preventative maintenance – pole inspection should be determined on the basis of a 4.5 year inspection cycle, as recommended by PB. Based on these considerations, the AER requested Ergon Energy to amend its forecast opex allowance to factor in an inspection cycle of 4.5 years.

Inspection programs

AER draft decision

The AER reduced Ergon Energy's opex allowance associated with its coincident visual inspection program. The AER considered that Ergon Energy runs a program that achieved a similar outcome—the full inspections program. In addition, the AER noted that the full inspections program forecast an increase in the number of full inspections to be undertaken in the next regulatory control period. Based on this information, the AER made an offsetting reduction to the coincident visual inspection program.[571]

This adjustment resulted in a reduction of $1.7 million ($2009–10) to forecast opex for the next regulatory control period.[572]

Revised regulatory proposal

Ergon Energy did not accept the draft decision to reduce funding associated with the coincident visual inspection program. Ergon Energy interpreted the draft decision to mean it was required to merge its overhead services inspection program with its coincident visual inspection program.[573] Ergon Energy stated:[574]

- the two programs have no overlap
- the two programs address different failure modes
- the two programs consist of different activities
- the full service inspection would incur higher costs than those estimated by Ergon Energy in its revised proposal if the visual inspection services program was incorporated into the full service inspection program.

Ergon Energy proposed that its original preventative maintenance forecast associated with its coincident visual inspection program be retained.[575]

Consultant review

PB considered the information presented by Ergon Energy and made the following observations:[576]

- The ground based coincident visual inspections are undertaken on a four year cycle and costed at $11.68 each. The inspections include: the visual inspection of overhead services; visual inspection of the above ground section of underground services that are attached to a pole in overhead areas; identification of targeted service types and constructions that no longer adhere with current standards that may need to be replaced in future maintenance initiatives; identification and recording of defects on Ergon Energy owned assets; and communication to

571 AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, p. 667.
572 AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, p. 668.
573 Ergon Energy, *Revised regulatory proposal,* January 2010, p. 154.
574 Ergon Energy, *Revised regulatory proposal,* January 2010, pp. 154–155.
575 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 155.
576 PB, *Review of Ergon Energy's revised regulatory proposal,* April 2010, p. 74.

property owners or occupiers of defects observed during inspections on the customer owned assets at the point of supply.

- The full inspections are undertaken on a twelve year cycle and costed at $150 each. These inspections are restricted to visual inspections and electrical testing at the customer connection point, in order to identify and address neutral connectivity defects and target the removal of bare wire, neutral screen concentric and parallel web twisted service cables.

PB stated an overlap of tasks exists between the coincident visual inspection program and the full inspection program. PB noted that when carrying out the coincident visual inspection program, the inspector would be required to pass along the entire length of the service wire in order to undertake the inspection and testing at the customer connection (program objectives of the full inspections program). PB considered that economies of scale existed which should be taken into account. It also considered that when carrying out coincident visual inspections at the supply point, there is potential for the full inspection tasks to be completed at the customer connection point. There was an opportunity for the streamlining of activities to occur, as it is on the same route as the coincident visual inspection program.

PB identified an overlap of tasks including the visiting location of the service and the visual inspection of the overhead service. PB considered that an asset manager seeking to deliver efficient and minimised costs would reduce the coincident visual inspections of customer services at the same rate that the full inspections are increasing after completion of the full inspections program in 2009–10.[577]

Based on its review of the revised regulatory proposal, PB maintained its original position and recommended a reduction of $1.7 million to take into account a reduction in the number of coincident visual inspections.[578]

AER considerations

The AER considers that there is some overlap of activities between the coincident visual inspection program and the full inspections program. As a result, economies of scale should be considered when estimating costs for both programs. The AER notes that PB has identified tasks relevant to both programs which can be carried out as part of one inspection rather than performed twice in two different inspections. The AER considers the streamlining of these functions is achievable within the next regulatory control period but may require greater coordination and management of assets on Ergon Energy's part.

The AER notes that Ergon Energy's Ellipse data management system is now established. There is capacity to make use of the Ellipse data management system to make informed coordination and organising decisions about its network operations. In addition, Ergon Energy now has ten years worth of network operations experience since its inception in 1999. The AER considers that Ergon Energy should have the

577 PB, *Review of Ergon Energy's revised regulatory proposal,* April 2010, p. 75.
578 PB, *Review of Ergon Energy's revised regulatory proposal,* April 2010, p. 75.

knowledge and managerial capacity to design the two inspection programs to take advantage of economies offered by coordinating the programs.[579]

It is noted Ergon Energy interpreted the draft decision to mean it was required to merge the full inspection program with the coincident visual inspection program. The AER stresses that this interpretation is incorrect. The AER considers that Ergon Energy can achieve some efficiency in service delivery, through better co-ordination of the two inspection programs. It is noted that PB identified some common tasks between the two programs. As a result, cost efficiencies can be achieved to remove the overlap of costs. To account for the likely efficiencies, the AER requested Ergon Energy to revise its forecast opex for coincident visual inspections by reducing the number of coincident visual inspections by the increase in the number of full inspections, once the full inspections program is established in 2009–10.

Endangered species, declared plants and cultural heritage regulatory obligations

AER draft decision

The AER reduced Ergon Energy's proposed opex allowance associated with the cumulative growth factor used to calculate Ergon Energy's preventative maintenance forecast relating to the endangered species, declared plants and cultural heritage regulatory obligations. The AER considered that this growth factor should be removed from the preventative maintenance forecast because insufficient economic justification was provided by Ergon Energy.[580] This adjustment resulted in a reduction of $4.7 million ($2009–10) to the forecast opex for the next regulatory control period.[581]

Revised regulatory proposal

Ergon Energy did not accept the draft decision to remove the cumulative growth factor concerning the management of its endangered species, declared plants and cultural heritage legislative requirements.[582] Ergon Energy proposed that its original preventative maintenance forecast associated with the cumulative growth factor be retained.[583]

Ergon Energy stated that the cumulative growth factor was used to calculate costs associated with the *Nature Conservation Act 1992 (amended 2005)*, the *Aboriginal Cultural Heritage Act 2003* and the *Land Protection (Pest and Stock Route Management) Act 2002*.[584]

Ergon Energy confirmed that its historical costs were limited and this was problematic when used as a basis to derive future costs associated with meeting these

579 The AER notes Ergon Energy sought and was allowed increased funding in the current and next regulatory control periods to establish the Ellipse data management system.

580 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 680–681.

581 AER, *Draft decision, Queensland draft distribution determination,* November 2009, pp. 680–681.

582 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 160.

583 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 160, 164.

584 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 160.

requirements. At the same time, it stated that future costs associated with meeting these obligations were likely to continue to increase.[585]

Ergon Energy stated that the relevant government agencies administering these legislative requirements regularly increased their compliance requirements. The nature of the legislation resulted in frequent changes based on the prevailing conditions. This added to the growing requirements of the government agencies, which in turn, increased compliance costs. Ergon Energy stated that failure to provide increased funding for these increasingly onerous requirements would likely result in either a significant funding shortfall or non–compliance with Queensland legislation. Ergon Energy noted that non–compliance with Queensland legislation could result in cost penalties and damage to its corporate reputation.[586]

Ergon Energy also stated that costs associated with meeting the regulatory obligations, including the cumulative growth factor component, are uncontrollable costs. Accordingly, Ergon Energy submitted that the AER should apply a step change test to determine if the cost should be allowed in the AER's final distribution determination. Ergon Energy stated that the step change criteria test used by Wilson Cook in the 2009 NSW Distribution Determination should be used to determine whether its costing proposal was prudent and efficient.[587]

Consultant review

PB reviewed the revised justification provided by Ergon Energy and considered that Ergon Energy had failed to provide any detailed justification or information to support its approach.[588]

PB stated that the cumulative growth increases sought by Ergon Energy did not constitute a step change in accordance with the Wilson Cook criteria. PB considered that any increase in activities associated with meeting the regulatory requirements were driven by continual changes in obligations rather than through any specific trigger or event.[589]

PB stated that the revised proposal provided no new information on what activities Ergon Energy's proposed growth factor allowance would cover in the next regulatory control period. PB noted that no evidence or description was provided by Ergon Energy on the nature of increasing and emerging requirements anticipated to be driven by the various government agencies. The lack of detail in describing the increased obligations on Ergon Energy provided no opportunity for PB to verify if the $100 000 per annum increase in each of the three areas was prudent or efficient.[590]

Given this lack of supporting detail, PB considered the proposed forecast increases are speculative in nature. As the proposal was not linked to any clearly identified factors associated with changing compliance requirements related to endangered species, declared plants and cultural heritage, PB maintained its recommendation to

585 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 160.
586 Ergon Energy, *Revised regulatory proposal,* January 2010, p. 160.
587 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 160.
588 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 76.
589 PB, *Review of Ergon Energy's revised regulatory proposa*l, Arpil 2010, p. 76.
590 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 76.

remove the effect of the cumulative growth factor incorporated for preventative maintenance opex relating to the endangered species, declared plants and cultural heritage regulatory obligations.[591]

AER considerations

The AER notes Ergon Energy based the need for a cumulative growth factor on the likelihood that compliance obligations are going to increase with respect to the *Nature Conservation Act 1992*, *Aboriginal Cultural Heritage Act 2003* and *Land Protection (Pest and stock route management) Act 2002*. However, Ergon Energy did not provide any specific information about likely changes to these Acts or how any likely changes will impact on its costs.

The AER notes that Ergon Energy requested that the increase in opex be considered as a step change as it considered that the forecast changes to these costs would meet the test developed by Wilson Cook.[592] Wilson Cook considered that for acceptance as a step change a cost 'ought to relate to a fundamental change in business environment arising from outside factors or be offset by customer benefits or cost efficiencies in other areas'.[593]

The AER is not satisfied that the proposed cumulative growth allowance meets the criteria of a step change test for the following reasons:

- it relates to hypothetical changes in regulatory obligations for which the cost impacts have not been assessed
- Ergon Energy's description of the hypothetical changes indicates they expect such changes to be incremental rather than fundamental in nature.

The AER considers that the proposed cumulative growth allowance is driven by anticipated continual changes in existing legislative obligations rather than through any specific trigger or event. Variations to operating conditions do not form the basis for a claim for a step change, but are a normal part of business operations.

Accordingly, the AER requested Ergon Energy to remodel its forecast opex allowance to remove the cumulative growth factor associated with its proposed preventative maintenance forecast.

Keys and locks for access gates

AER draft decision

The AER did not accept Ergon Energy's preventative maintenance proposal to install 300 000 locks and keys. The AER considered that Ergon Energy did not provide sufficient justification to support this proposal. This adjustment resulted in a reduction

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591 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 76.

592 The step change test is used to recognise that base year opex should be adjusted for costs arising from new or changed functions and legislative obligations (termed 'step change'). The step change test was devised by Wilson Cook and was used in: AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009.

593 Wilson Cook, *Review of proposed expenditure of ACT and NSW DNSPs*, Volume 1, October 2008, p. 51.

of $8.4 million ($2009–10) to the forecast opex for the next regulatory control period.[594]

Revised regulatory proposal

Ergon Energy noted its original forecast contained errors affecting the forecast amount. Ergon Energy submitted an updated forecast that represented a reduction of $6 million from its regulatory proposal. Table 8.7 shows Ergon Energy's revised proposed keys and locks program forecast.[595]

Table 8.7: Ergon Energy revised opex forecast for the keys and locks program ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Forecast opex	1.2	2.5	1.4	0	0	5.1

Source: Ergon Energy, email response to AER request, 15 February 2010.

Ergon Energy stated its proposed standard keys and locks program was not limited to covering access tracks, as originally submitted. It stated its proposed standard keys and locks program extended to all sub–transmission and distribution switching points, padmount and ground enclosed distribution stations and access track gates.[596]

In support of its revised regulatory proposal, Ergon Energy provided a business case and updated unit cost estimates established via a competitive tender process.[597]

Consultant review

PB reviewed the new information provided by Ergon Energy. It noted that the revised program takes into account the installation of less than 41 000 locks and is based on:[598]

- one lock per four kilometres of track
- two locks per padmount substation
- 1.5 locks (on average) per ground enclosed substation
- one lock per air-break switch
- 2000 keys to be supplied
- co–ordinating the roll-out with existing inspection and maintenance programs.

PB noted the business case provided by Ergon Energy included an options analysis, and noted the security, health and safety risks associated with unauthorised access to

594 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 680–681.
595 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 161–162.
596 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 161–162.
597 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 161–162.
598 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 77.

Ergon Energy's sites. PB also noted the scope of works was transparent and the cost estimates well supported.[599]

Overall, PB considered the revised keys and locks program was prudent and efficient.[600]

AER considerations

The AER notes Ergon Energy provided a well substantiated forecast for its revised keys and locks program in its revised regulatory proposal. The revised keys and locks program corrects errors in the original forecast and is supported by a relevant business case and referenced cost estimates. The AER also notes PB's conclusion that the revised keys and locks program is prudent and efficient. The AER considers Ergon Energy's revised keys and locks program represents an efficient forecast of the costs required to address the security and health and safety risks associated with unauthorised access to Ergon Energy's sites.

AER conclusion

Ergon Energy advised that the adjustment associated with preventative maintenance activities (excluding input cost escalation) results in a reduction of $23 million ($2009–10) to the forecast opex for the next regulatory control period.[601] This amount is comprised of the following adjustments to the revised regulatory proposal:

- $17.1 million reduction for inspection cycles
- $1.1 million for coincident inspection programs
- $4.7 million for regulatory obligations.

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's preventative maintenance opex forecast reasonably reflects the opex criteria, including the opex objectives. The AER considers reducing Ergon Energy's preventative maintenance opex forecast by $23 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.

8.4.2.2 Corrective maintenance

Removal of old poles

AER draft decision

The AER did not accept Ergon Energy's proposed scope change increase in the corrective maintenance base year costs concerning the dismantling of old lines that have been replaced. The AER was concerned these costs would otherwise be double

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[599] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 77.
[600] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 77.
[601] Ergon Energy, reponse to modelling request, 22 April 2010, PRP1028c.

counted as they should already be included as part of the capex program to replace the old lines.[602]

The exclusion of the proposed scope changes resulted in a reduction of $9.4 million ($2009–10) to forecast opex for the next regulatory control period.[603]

Revised regulatory proposal

Ergon Energy did not agree with the draft decision that there was a double counting of costs. Ergon Energy stated the double counting of costs did not exist as costs associated with the dismantling of old lines covered situations where 'the asset is no longer required or where the asset continued in service for some time after a capital project was completed and is now no longer required'.[604]

Ergon Energy submitted that its financial policies required assets to be written off in order for them to be expensed. In the situation of asset replacement projects, the dismantling of old assets replaced was included as part of the capital project costs.[605]

Consultant review

PB stated that clarification provided by Ergon Energy regarding the scope of work showed that the work did not cover the situation of 'dismantling of old lines that have been replaced' but is associated with the general activity of dismantling old lines.[606]

PB stated that dismantling of old lines is an ongoing activity and should have been included in base year costs. PB concluded that the scope change was therefore not prudent and efficient. PB recommended excluding the scope change for dismantling old lines from the opex forecast.[607]

AER considerations

Ergon Energy stated that corrective maintenance is the most appropriate means to facilitate the removal of old lines, and made it clear that this work is not undertaken as part of a capital project. The AER also notes that Ergon Energy explained that lines not in use may not be dismantled for several years after they are taken out of service, due to the difficulty in obtaining line routes and the possibility of using the line at some time in the future.[608]

The AER accepts Ergon Energy's clarification on the scope of the work and now considers that the proposed scope change does not double count capital costs.

However, Ergon Energy has not provided sufficient information to demonstrate that the dismantling of old lines should be treated as a scope change to corrective maintenance base year expenditures. The AER notes PB's opinion that dismantling old lines is an ongoing activity that should already be included in base year expenditure. Ergon Energy's statement that the decision to remove an old line can

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602 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 672.
603 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 671–672.
604 Ergon Energy, *Revised regulatory proposal,* January 2010, p. 157.
605 Ergon Energy, *Revised regulatory proposal,* January 2010, p. 157.
606 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 78.
607 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 79.
608 Ergon Energy, email response to PB.ERG.RRP.03, 19 February 2010.

occur several years after the event that led to the line been taken out of service, also adds weight to the consideration of the activity as an ongoing component of corrective maintenance.[609]

The AER considers it is inappropriate to include a scope change for the ongoing activity of dismantling old lines to the base year corrective maintenance forecast. The AER requested Ergon Energy to amend its model to remove the proposed scope change from the corrective maintenance base year amount.

Work volume in access track programs

AER draft decision

The AER did not accept Ergon Energy's proposed step change increase concerning the 100 per cent increase in access track work volume in 2009–10. The AER noted that Ergon Energy proposed an increase in preventative maintenance spending in the next regulatory control period and this would result in a decrease to its corrective maintenance forecast. However, the AER was not able to ascertain how the expected reduction in corrective vegetation maintenance was incorporated into Ergon Energy's modelling. Accordingly, the AER replaced the 100 per cent increase in work volume with a 30 per cent increase in work volume in 2009–10.[610]

This adjustment resulted in a reduction of $27.5 million ($2009–10) to the forecast opex for the next regulatory control period.[611]

Revised regulatory proposal

Ergon Energy did not agree with the draft decision and stated that its original 100 per cent work volume increase in 2009–10 should be retained.[612]

Ergon Energy stated the proposed works for access tracks are a separate program of works to that for vegetation management, and the new vegetation management strategy will not impact on the proposed program for access tracks. It noted PB's report on its access tracks forecast did not state there would be flow on benefits arising in the access tracks program as a result of other opex spending, as claimed by the AER. Ergon Energy also stated interactions with other inspection programs will not result in efficiencies in the access tracks work program.[613]

Ergon Energy claimed that the access track work program step change is justified as:[614]

- there is a 128 per cent increase in inspections required (in terms of kilometres of track to be inspected)
- its historical corrective maintenance expenditure has been inadequate resulting in a significant backlog of access track inspection and remediation work

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609 Ergon Energy, email response to PB.ERG.RRP.03, 19 February 2010.
610 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 680.
611 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 681.
612 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 162–164.
613 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 162.
614 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 163.

- asset inspection contractors have suggested increasing their rates to account for vehicle damage and inspection delays due to the poor condition of access tracks.

Ergon Energy stated it has used a constant defect rate of 18.5 per cent with a constant unit cost per kilometre of track remediated in forecasting the 100 percent work volume increase for the next regulatory control period. Ergon Energy noted the 128 per cent increase in kilometres of track inspected results in a 128 per cent increase in direct costs associated with access track remediation. Ergon Energy estimated the AER's proposed 30 per cent increase in work volume for access tracks corresponded to a defect rate of 10.5 per cent, lower than its own forecast rate of 18.5 per cent, which it claimed is likely to be an underestimate.[615]

Ergon Energy also submitted it is not likely to achieve a steady state access track program within the next regulatory control period, due to the 4 year inspection cycle and the current backlog of access track work. Ergon Energy stated it did not model increased efficiency in the forecasting process as it does not consider such efficiencies will be realised within the next regulatory control period.[616]

Ergon Energy stated the 100 per cent increase in access track work volume is necessary for it to meet its regulatory obligations and to address existing backlogs.[617]

Consultant review

PB considered that Ergon Energy's step change proposal regarding work volume for access tracks meets the Wilson Cook step change criteria test because the work volume increase was necessitated by changing compliance obligations.[618]

PB considered Ergon Energy's analysis of detailed historical defect ratios to be esoteric as Ergon Energy advised that its access track corrective maintenance program was based on arbitrary information. PB also considered Ergon Energy overstated its historical unit rate in its forecasts, and noted the actual unit rate was implicitly incorporated into PB's recommendation.[619]

Huegin assumed that PB used a defect rate of 10.5 per cent to calculate its recommended 30 per cent increase in work volume for Ergon Energy. PB stated this assumption was incorrect because it did not directly apply any defect rate in their modelling to arrive at the recommended reduction.[620]

PB noted its recommendation focussed on the opex allowance, rather than the specific defect ratio or unit rates that were manufactured by Ergon Energy to support a doubling of its access tracks opex forecast.[621]

PB stated a 30 per cent increase in work should be included in the access tracks opex forecast to reflect a moderate increase in corrective maintenance that captures

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615 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 163.
616 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 164.
617 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 164.
618 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 80.
619 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 80.
620 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 80.
621 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 80.

opportunities from proactive risk management and efficiencies in subsequent inspection cycles from 2014–15. PB recommended reducing Ergon Energy's corrective maintenance opex amount by $22.9 million, based on a 30 per cent work volume increase.[622]

PB also recommended removing the 1.6 per cent network growth escalator from Ergon Energy's opex modelling to account for new assets being added to the asset pool. PB assumed that new access tracks should already conform to acceptable design standards and should not require remediation within the next regulatory control period. This resulted in an additional $4.6 million adjustment.[623]

AER considerations

The AER considers the increase in work volume proposed meets the step change criteria because it relates to a specific change in compliance obligations that Ergon Energy must meet.

However, the AER does not accept Ergon Energy's proposal for a 100 per cent work volume step change increase in relation to its planned corrective maintenance activities over the next regulatory control period.[624]

The AER notes Huegin's statement that PB's modelling is not robust due to the defect rate used in the modelling. Ergon Energy argued that PB's implied defect rate is too low and a higher defect rate of 18.5 per cent should be used. However, the robustness of the defect rate cited by Ergon Energy is questionable, given the inherent flaws in the data underpinning it. In particular, the AER notes Ergon Energy stated it estimated 'an arbitrary defect rate of 18.5 per cent and an arbitrary unit rate' that was based on a doubling of the expenditure in 2010–11. The AER notes Ergon Energy's defect rate and unit rate were not based on any historical data.

The AER notes the concern expressed by Huegin that a 30 per cent increase in work volume activity would not be sufficient to address the corrective maintenance for access tracks likely to be undertaken by Ergon Energy in the next regulatory control period. The AER notes that Huegin formed its conclusion based on analysis of Ergon Energy's historical work volumes and defect rates.

The AER does not consider the historical data that Huegin relied on as part of its analysis to be complete or accurate. The AER notes the data used by Huegin represented only a portion of remediation work reported by field staff. The AER notes Ergon Energy confirmed that the sample dataset used as part of its proposed corrective maintenance opex forecast was inappropriate to use over the entire length of Ergon Energy's network.[625] Furthermore, this dataset only contained entries regarding access tracks that had defects identified and not those that were inspected and found to be defect free. Therefore the AER does not accept Huegin's statement

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622 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 81.

623 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 80–81. PB removed the network growth escalator included by Ergon Energy in its NARMCOS model forecasts.

624 Ergon Energy, *Regulatory proposal*, July 2009, AEP–15, Access tracks and equipment sites, p. 8.

625 Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP938c, Huegin report, pp. 93–94.

that the 30 per cent work volume increase may not be sufficient for Ergon Energy to fund the required corrective maintenance on its access corridors and sites.

The AER considers PB's recommendation that a work volume increase of 30 per cent reflects an efficient volume of activity that a prudent operator in the circumstances of Ergon Energy would require to achieve the opex objectives. This 30 per cent work volume increase reflects the impact on network opex in accordance with Ergon Energy's proactive risk management approach, and the expectation that Ergon Energy will be able to realise some efficiencies by the commencement of the next inspection cycle in 2014.

The AER considers that a 30 per cent increase in work volume would be sufficient for Ergon Energy to address the corrective maintenance for access corridors and sites likely to be undertaken by Ergon Energy in the next regulatory control period.

The AER notes PB has also recommended removing the network growth escalator from this component of corrective maintenance. The AER considers this is reasonable on the basis that new access tracks should meet required standards and should not require corrective maintenance. The AER notes Ergon Energy did not separately address this matter in its revised regulatory proposal.

The AER requested Ergon Energy to amend its model to incorporate the reduced work volume increase as part of its corrective maintenance forecast, and to remove the network growth escalation from this component of the opex forecast.

AER conclusion

Ergon Energy advised that the adjustment associated with corrective maintenance activities (excluding input cost escalation) results in a reduction of $38 million ($2009–10) to the forecast opex for the next regulatory control period. This amount is comprised of the following adjustments to the revised regulatory proposal:

- $9.5 million reduction for removal of old poles
- $28 million reduction for access track work volumes.

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's corrective maintenance opex forecast reasonably reflects the opex criteria, including the opex objectives. The AER considers reducing Ergon Energy's corrective maintenance forecast by $38 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.

8.4.2.3 Forced maintenance

Offset from asset replacement capex and preventative and corrective maintenance opex

AER draft decision

The AER did not accept Ergon Energy's proposed opex allowance on forced maintenance activities. The AER considered that a reduction in forced maintenance costs was necessary to offset Ergon Energy's proposed increased spending in asset replacement capex programs and increased spending in preventative and corrective maintenance opex.

This adjustment resulted in a reduction of $6.7 million ($2009–10) to the forecast controllable opex for the next regulatory control period.[626]

Revised regulatory proposal

Ergon Energy did not agree with the draft decision to reduce its forced maintenance expenditure. Ergon Energy noted the AER proposed to reduce both asset replacement expenditure and preventative maintenance expenditure, and stated the positive effect on forced maintenance will not occur if these opex reductions are implemented. In support of this, Ergon Energy referred to the Huegin report. Huegin asserted the following drawbacks with PB's report:[627]

- PB assumed that 40 per cent of forced maintenance faults arose from poor plant condition or performance
- PB's assumption is not supported by independent academic research
- PB's assumption is not supported by Ergon Energy data
- independent research, as well as Ergon Energy's own data, indicated that external factors (including weather and animals) are the most significant contributor to forced maintenance.

Huegin also noted a benchmarking study that found Ergon Energy's average faults triggered by equipment and transformer failure was around 14 per cent from 2003–04 to 2006–07.[628]

Ergon Energy stated its forced maintenance was not forecast to grow, despite an increasing network size.[629]

Consultant review

PB did not consider that Ergon Energy's revised regulatory proposal presented any new information to demonstrate that its cost estimates were prudent and efficient. PB provided the following clarification in response to the statements made in the Huegin report.

The 40 per cent defect rate

PB stated that it did not assume that 40 per cent of Ergon Energy's forced maintenance activities were the result of plant condition and performance faults. The 40 per cent rate was not used in any of PB's modelling concerning Ergon Energy's forced maintenance activities. PB stated that it used this defect rate as a guide in

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626 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 674–675.
627 Ergon Energy, *Revised regulatory proposal,* January 2010, pp. 157–158.
628 Ergon Energy, *Revised regulatory proposal,* January 2010, pp. 157–158.
629 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 157–158.

undertaking its review of Ergon Energy's proposed forced maintenance opex forecast.[630]

PB noted the SAHA International Ltd (SAHA) benchmarking study that provided an alternative defect rate of 14 per cent relevant to Ergon Energy's operating conditions. However, PB considered this rate to be arbitrary as it did not use any defect ratio assumptions to arrive at its recommendation.

Forced maintenance modelling

In considering the opex requirement for forced maintenance PB reviewed Ergon Energy's modelling, and hence targeted its recommendations at specific asset classes, rather than the whole opex component.

PB recognised that some forced maintenance activities related to repair works were caused by external factors such as adverse weather conditions and other factors that are beyond the control of the network operator. However, PB considered that the uncontrollable costs were appropriately factored into the forced maintenance base year costs.[631]

While some of the forced maintenance activities would be unavoidable costs, PB considered that a portion of the costs arising from external events were avoidable as a result of increased spending in other areas of network opex. PB stated that Ergon Energy's planned increased investment in vegetation management works and repairs and maintenance works on access corridors and sites would result in a material reduction in forced outages due to external factors such as storms and weather. PB considered that increased spending on these other areas of network opex would make the assets more resilient and resistant to adverse events.

PB noted that Ergon Energy's modelling reduced forced maintenance requirements for vegetation management based on the significant increase in preventative and corrective maintenance for this category. PB extended the principles used by Ergon Energy to forecast its vegetation forced maintenance to the access tracks and sites assets, given that Ergon Energy is introducing a proactive preventative and corrective maintenance program for these assets.[632]

PB also noted Ergon Energy's modelling for 19 other asset classes included population growth rates, effectively accounting for an increase in network size.[633]

PB considered a flat forced maintenance forecast to be prudent and efficient in all asset classes except vegetation management, and access corridors and sites. For the latter category PB considered reductions in forced maintenance were justified.[634]

PB recommended two distinct adjustments:[635]

630 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 83.
631 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 83.
632 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 83.
633 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 83.
634 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 83.
635 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 84.

- removal of the growth factor associated with Ergon Energy's increasing asset base. PB estimated this growth factor associated with asset replacement capex activities to represent $2.3 million

- reduction in forced maintenance opex for access corridors and sites. PB considered that increased maintenance works in other areas of the network would reduce the need to carry out forced maintenance works. This represented a $4.5 million adjustment.

PB considered that these adjustments represented a reasonable proxy for offsetting forced maintenance spending due to planned increased spending in other areas of network activity.[636]

PB acknowledged that it rejected elements of Ergon Energy's asset replacement capex expenditure proposal elsewhere in its report.[637] PB stated that it had accounted for the adjustment in relation to asset replacement capex when informing its view of Ergon Energy's forced maintenance opex proposal.[638]

AER considerations

The AER notes Ergon Energy rejected the draft decision and has relied on a report by Huegin to support its forced maintenance opex forecast.

Impact of plant condition and performance

The AER's draft decision was based on PB's review of Ergon Energy's regulatory proposal. In response to the draft decision Huegin stated that PB's assumptions regarding causes of equipment failure were not supported by independent academic research or by Ergon Energy data. Huegin noted a benchmarking study that estimated equipment failure from plant condition was around 14 per cent for Ergon Energy – not 40 per cent as assumed by PB.

The AER notes that the estimated proportion of average failures caused by poor plant condition as derived by SAHA, have been interpreted by PB to be closer to 40 per cent than the 14 per cent stated by Huegin. Notwithstanding the lack of agreement over the interpretation of the benchmarking analysis the AER notes PB did not use the equipment failure rate to estimate its recommended efficient forced maintenance opex. For this reason, while noting the benchmarking report, the AER does not consider the research on fault causes materially impacts on PB's recommendation or the AER's conclusions.

Impact of replacement capex and other maintenance activities

The AER notes Ergon Energy stated its forced maintenance forecast was predicated on its proposed asset replacement capex and preventative and corrective maintenance opex forecasts being accepted by the AER. However, the AER while approving substantial increases in the capex and opex allowances for Ergon Energy has made necessary reductions to ensure the forecasts only reflect efficient levels of

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636 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 83.

637 PB recommended a 10 per cent reduction to Ergon Energy's asset replacement capex proposal, which is equivalent to a $1.1 billion reduction in the proposed forecast capex allowance.

638 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 83. In particular, footnote 220.

expenditure. The AER considers Ergon Energy will be able to undertake prudent network management with the revised capex and opex allowances, and does not expect there to be any detrimental impact on forced maintenance arising from its estimation of efficient asset replacement capex and preventative and corrective maintenance allowances.

Further, the AER considers that Ergon Energy has not appropriately captured the expected impact of its asset replacement capex program and increased spending on other maintenance activities into its forced maintenance forecast. The AER considers increased spending in these other areas of the network should contain and reduce forced maintenance opex. The impact should be accounted for through:

- the removal of the growth escalation where this is applied to specific asset classes, in recognition that Ergon Energy has stated that the forced maintenance forecast does not grow despite the increasing network size
- extending the modelling treatment of vegetation management forced maintenance to the access corridors and sites forced maintenance to recognise the new proactive preventative and corrective maintenance program for these assets.

The AER considers that the benefits associated with increased spending in relation to asset replacement activities and proactive maintenance activities should be incorporated into Ergon Energy's forced maintenance forecast opex allowance.

The AER requested Ergon Energy to amend its model to factor in these savings.

The AER considers the cost estimates associated with uncontrollable events (such as faults caused by third parties, or weather) have been factored into Ergon Energy's forced maintenance forecast. The AER notes that historical data relating to the likelihood, volume and cost impacts of rectifying assets damaged as a result of uncontrollable events have been used as a basis for informing the forced maintenance forecast for the next regulatory control period.

Ergon Energy advised that the adjustment associated with forced maintenance activities (excluding input cost escalation) results in a reduction of $11 million ($2009–10) to the forecast opex for the next regulatory control period.[639]

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's reports and other material, the AER is not satisfied that Ergon Energy's forced maintenance opex forecast reasonably reflects the opex criteria, including the opex objectives. The AER considers reducing Ergon Energy's forced maintenance opex forecast by $11 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.

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[639] Ergon Energy, response to modelling request, 22 April 2010, PRP1028c.

8.4.2.4 Other operating costs

Guaranteed service level payments

AER draft decision

The AER approved Ergon Energy's proposed opex to cover its GSL obligations. The AER approved Ergon Energy's GSL forecast of $66 000 per annum ($2009–10) to make payments to customers when the level of service they receive in relation to defined measures, falls below specified levels.

Revised regulatory proposal

Ergon Energy increased its GSL component of opex forecast to $1.5 million per annum to cover the new regulatory requirements set out in the QCA final decision on amendments to the *Electricity Industry Code* regarding GSL payments.[640]

Ergon Energy stated it did not have a complete understanding of its GSL obligations when it submitted its regulatory proposal because the QCA final decision had not been released.[641]

Ergon Energy forecast its GSL payments by:[642]

- maintaining the same level of actual and potential GSL payments, as originally submitted in its July 2009 regulatory proposal
- adding on the 30 per cent increase in GSL payments and costs associated with moving to an automated GSL payment system.

Consultant review

PB reviewed Ergon Energy's updated GSL payments forecast of $1.5 million per annum, and the forecasting method used by Ergon Energy. PB noted that Ergon Energy's forecast was based on a single year of data (2009), and the data showed considerable volatility between the two years that are available (2008 and 2009). Given the level of volatility in the number of GSL payments that would meet the new criteria in some categories, PB recommended using an average of the two years data as the basis for the forecast.[643]

PB recommended a reduction in the GSL forecast of $0.3 million per annum.[644]

AER considerations

The AER notes the QCA's final decision on GSL payments was made in October 2009, after Ergon Energy lodged its regulatory proposal in July 2009. The amended regulatory requirements take effect from 1 July 2010 and include:[645]

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640 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 169.
641 QCA, *Final decision, Proposed amendments to the Electricity Industry Code regarding customer claims for Guaranteed Service level (GSL) payments*, October 2009.
642 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 170.
643 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 90.
644 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 90.

- a requirement to automatically make GSL payments to affected customers rather than wait for a customer to initiate a claim
- a 30 per cent increase in the level of GSL payments, for each type of GSL.

Ergon Energy has collected data on the incidence of potential GSL claims, for 2008 and 2009, even where the GSL payments have not been claimed by customers. Ergon Energy used this information to derive a constant forecast of GSL payments of $1.5 million per year, which incorporates customer growth of 2 per cent and the 30 per cent increase in GSL payments required under the revised *Electricity Industry Code*.

The AER reviewed Ergon Energy's modelling and PB's report and considers the methodology and data used to derive likely GSL payments in the years 2008 and 2009 is reasonable. The AER notes PB's review of Ergon Energy's forecasting methodology and considers that the use of an average measure will result in a better forecast, especially where the underlying data is volatile. With the variation in the number of potential GSL payments as great as ±50 per cent for some measures, the AER considers the forecast should be based on an average of the two years for which data is available.

Ergon Energy advised that the adjustment associated with the revised estimation of GSL payments is $1.6 million ($2009–10) to the forecast opex for the next regulatory control period.[646]

AER conclusion

For the reasons discussed, and as a result of the AER's analysis of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast of GSL payments opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed GSL payments opex by $1.6 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.

Metering and customer service costs relating to alternative control services

AER draft decision

The AER did not accept Ergon Energy's forecast opex allowance for metering and customer service activities. The AER identified a double count of alternative control metering and customer service costs as part of the other operating costs forecast for Ergon Energy's standard control services.[647]

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645 QCA, *Final decision, Proposed amendments to the Electricity Industry Code regarding customer claims for Guaranteed Service level (GSL) payments*, October 2009, pp. 3, 9–11.

646 Ergon Energy, response to modelling request, 22 April 2010, PRP1028c.

647 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 685–689.

The AER estimated an adjustment of $80 million ($2009–10) to the forecast other operating costs opex for the next regulatory control period, specifically:[648]

- $30 million for metering service costs
- $50 million for customer service costs.

Revised regulatory proposal

Ergon Energy did not accept the draft decision regarding metering and customer service costs.[649]

Ergon Energy stated it presented incorrect data in its supporting documentation provided as part of its July 2009 regulatory proposal and this led to the AER's conclusion.[650]

Ergon Energy stated that it provided updated and corrected spreadsheets to the AER during the draft determination process. It stated that this documentation was not given due consideration by the AER for the purposes of its draft decision.[651] Ergon Energy stated the sources of error arose from data sources not being in comparable dollar terms, the differing treatment of overheads and the classification of services not being done in accordance with its approved CAM.

With respect to Ergon Energy's claim that its customer service and meter reading forecast was a prudent and efficient estimate, Huegin noted:[652]

- the substitute forecast in the draft decision is significantly lower than Ergon Energy's current expenditure
- the substitute forecast in the draft decision is significantly lower than other DNSPs' expenditures
- the substitute forecast represented an unachievable outcome for Ergon Energy.

Consultant review

PB considered the information provided in Ergon Energy's revised regulatory proposal, including the information which Ergon Energy claimed was not given due consideration as part of the draft determination process, was not sufficient for its analysis. PB noted it relied on a document provided by Ergon Energy (prepared by the responsible workgroup) which Ergon Energy used to inform its budget forecasts.[653] Where the data within the document could not be reconciled against the regulatory information notice (RIN), PB sought further information from Ergon Energy. Based on the additional information provided by Ergon Energy, PB considered that:[654]

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648 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 685–689.
649 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 165–167.
650 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 165–167.
651 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 165–167.
652 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 165–167.
653 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 85.
654 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, pp. 86–87.

- overall around 80 per cent of the expenditure is supported by additional information ($83 million, ($2007–08))

- the information in the RIN excluded overheads and was presented in $2007–08, the information in the *Customer care and meter reading* document was less clearly defined, but the conservative assumption of being in $2007–08 and excluding overheads was applied

- the double count of costs in relation to meter reading activities in Ergon Energy's opex model had been corrected by a transfer of some meter reading costs from alternative control services to standard control services

- costs were overstated in the customer service category in relation to standard control services. Based on the new information provided, PB was unable to verify or reconcile how customer service costs were allocated between standard and alternative control services. After reviewing the business case study provided by Huegin, PB found that Ergon Energy's customer service opex per customer was higher than the three comparator businesses

- Ergon Energy had been provided with the opportunity to outline further detailed corrections to support its original forecasts (in terms of the detailed activities and their classification), particularly in relation to Ergon Energy's customer service costs. PB noted Ergon Energy had not provided any further information.

PB recommended that Ergon Energy revise its adjustments in relation to customer service costs only, as it considered Ergon Energy had corrected the material errors concerning the meter reading costs. PB based its assessment on the historical and forecast trend data provided by Ergon Energy. PB also took into consideration the comparative benchmarking information included within Ergon Energy's revised regulatory proposal.

Given that 80 per cent of direct costs were supported, PB applied this proportion to the customer services opex forecast to estimate a reduction of $33 million ($2009–10) for the next regulatory control period.

AER considerations

The AER considers the opex forecasts provided by Ergon Energy must be unambiguously related to either standard control services or alternative control services. Ergon Energy must be able to provide sufficient evidence to support its claims that the forecasts only relate to correctly classified opex, in this case standard control metering and customer service opex. The information provided by Ergon Energy in its regulatory proposal was not unambiguous in this regard.

Ergon Energy stated the *Customer care and meter reading* document informed its budget forecasts, yet the forecast for standard control metering and customer service opex was approximately 50 per cent less than that shown in the opex forecasts.[655] As Ergon Energy could not reconcile the discrepancy, the AER made an adjustment to

[655] Ergon Energy, *Regulatory proposal*, July 2009, AR272c_EE_Customer Care Forecast Report including meter read.pdf; and RIN.

the forecast opex for metering and customer service opex, based on the estimated reduction derived by PB.[656]

The AER has reviewed the revised information provided by Ergon Energy in relation to customer service and metering costs.

Ergon Energy stated that sources of error in the information relied on by the AER derive from non–comparable dollar terms, the impact of shared costs (overheads) and service classification not being undertaken in accordance with the approved CAM.[657] The AER notes PB has ascertained the RIN data is all in $2007–08 and does not include overheads, and assumed that the *Customer care and meter reading* document is also presented in similar terms.[658] The AER notes that Ergon Energy stated the *Customer care and meter reading* document is in $2007–08 nominal terms, and has interpreted this to mean $2007–08.[659] The AER also notes that the *Customer care and meter reading* document specifies that some overheads are excluded, but it is not clear if all overheads are excluded.[660] Therefore, the AER considers that to the extent that the definition of the forecasts in the *Customer care and meter reading* document is ambiguous, it is reasonable to apply conservative assumptions to enable the information to be interpreted. The AER considers PB's assumption that the information excludes overheads and is in $2007–08 terms is a reasonable and conservative assumption.

The AER notes that Ergon Energy corrected the modelling errors to remove alternative control meter reading costs from the proposed standard control opex forecast.[661] The AER notes PB has verified this adjustment to Ergon Energy's standard control opex model. On this basis, the AER is satisfied that Ergon Energy's revised forecast in relation to metering costs does not include any costs related to alternative control services.

With respect to customer service costs, the AER notes there is still some ambiguity about the costs that should be attributed to standard control services. Ergon Energy corrected the allocation of 7 specific activities, and as noted above justified its inability to further reconcile the data in the opex forecast model with the *Customer care and meter reading* document on the basis of non–comparable dollar terms, the impact of shared costs (overheads) and service classification not being undertaken in accordance with the approved CAM.

Ergon Energy stated the remaining difference (approximately $21 million) was:[662]

> insignificant enough to be considered as being within the inherent range of error related to comparison of historical data with forecast data.

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656 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 686, 689.
657 Ergon Energy, EE reponse to PB.ERG.RRP.01 – opex – other operating costs, 1 March 2010.
658 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 68.
659 Ergon Energy, EE reponse to PB.ERG.RRP.01 – opex – other operating costs, 1 March 2010.
660 Ergon Energy, *Regulatory proposal*, July 2009, AR272c_EE_Customer Care Forecast Report including meter read.pdf, p.1.
661 Ergon Energy, EE response to PB.ERG.RRP.01 – opex – other operating costs, 1 March 2010.
662 Ergon Energy, EE response to PB.ERG.RRP.01 – opex – other operating costs, 1 March 2010.

Ergon Energy also provided benchmarking comparisons developed by Huegin to demonstrate the allowance in the draft decision is inadequate, compared to historical expenditure and other DNSPs.

Despite Ergon Energy's claim that the outstanding difference is insignificant, the AER considers that a difference of $21 million ($2007–08) should be able to be explained. Ergon Energy's inability to reconcile the information used to inform its budget forecasts and its opex forecasts means the AER does not consider Ergon Energy's claim that the opex forecast only incorporates standard control services has been substantiated.

The AER notes Ergon Energy has flagged doubt about the accuracy of the allocation of costs between alternative and standard control services in the *Customer care and meter reading* document and concluded the opex forecast should be accepted as only relating to standard control services. The AER accepts that the *Customer care and meter reading* document was not developed for regulatory purposes and as such an exact reconciliation of costs presented in the opex forecasts and the *Customer care and meter reading* document may not be possible. However, given that it was used to inform Ergon Energy's opex forecasts the AER considers the information should be reconciled to a greater extent than Ergon Energy has managed. The AER considers Ergon Energy has not sufficiently demonstrated its forecast customer service opex solely relates to standard control services.

The AER also notes the comparisons of metering and customers service costs undertaken by Huegin. PB noted that the nature of meter reading activity and the accuracy of historical costs suggest that it is unlikely that any significant alternative control meter reading services are now included in Ergon Energy's standard control opex. Therefore the AER considers the discrepancy in the data presented by Ergon Energy should be attributed to customer services opex.

PB recommended a 20 per cent reduction to total customer service costs on the basis that only 80 per cent of the direct costs are clearly supported in the information provided by Ergon Energy. This results in a reduction of $33 million to be applied to customer services opex forecasts. The AER considers that applying a reduction of $33 million to customer services opex will ensure that any alternative control services costs that have been included in this opex forecast are excluded from the standard control service opex allowance.

AER conclusion

For the reasons discussed, and as a result of the AER's analysis of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast of customer service opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed custeomer service opex by $33 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.

Demand management project management costs

AER draft decision

The AER did not accept Ergon Energy's opex allowance covering the incremental increase in demand management costs in relation to project management activities.[663]

This adjustment resulted in a reduction of $2.5 million ($2009–10) to the forecast controllable opex for the next regulatory control period.[664]

Revised regulatory proposal

Ergon Energy did not accept the draft decision on project management costs and stated its forecast included a number of project and ongoing management costs for the programs. It noted some costs are captured as one off costs but there are ongoing incremental costs associated with managing demand management initiatives. In this case, the incremental costs resulted in the expenditure of $2.5 million.[665]

Ergon Energy submitted that the AER should recognise the need for an ongoing incremental cost associated with demand management projects.[666]

Consultant review

PB noted that Ergon Energy did not provide any new or additional information in its revised regulatory proposal to support its proposed incremental project management costs.

PB considered that demand management costs should not increase even though the volume of demand management projects is forecast to increase in the next regulatory control period. In addition, PB maintained that economies of scale and productivity improvements should be factored into the forecasts. These factors would offset the incremental costs associated with the increase in the number of demand management projects.[667]

In the absence of any new information, PB maintained its recommendation to reduce the demand management project management opex forecast by $2.6 million.[668]

AER considerations

The AER considers that Ergon Energy is seeking an increase in opex allowance to provide for an increase in work volume expected in the next regulatory control period in respect of demand management initiatives.

The AER notes that no detailed justification was provided by Ergon Energy to support its claim that the incremental costs for managing the demand management initiatives should be recognised in the forecast opex allowance. The AER observes that Ergon Energy's revised proposal did not provide any evidence such as a description of

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663 AER, *Draft Decision*, November 2009, pp. 687, 689.
664 AER, *Draft Decision*, November 2009, pp. 687, 689.
665 Ergon Energy, *Revised regulatory proposal,* January 2010, pp. 167–168.
666 Ergon Energy, *Revised regulatory proposal,* January 2010, pp. 167–168.
667 PB, *Review of Ergon Energy's regulatory proposal*, November 2009, p. 88.
668 PB, Review of Ergon Energy's revised regulatory proposal, April 2010, pp. 87–88.

expected increased activities or information on the nature of the increasing and emerging management requirements.

In the absence of new information in Ergon Energy's revised regulatory proposal, the AER confirms its draft decision to exclude $2.6 million of forecast demand management project management opex.

AER conclusion

For the reasons discussed, and as a result of the AER's analysis of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast of project management opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed project management opex by $2.6 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.

Shared costs (overhead costs) – ICT projects

AER draft decision

The AER did not accept Ergon Energy's proposed opex allowance in relation to the opex component of shared ICT costs because the AER did not accept Ergon Energy's proposed new capability ICT capex project to be undertaken by SPARQ.[669]

This adjustment resulted in a reduction of $6.4 million ($2009–10) to the forecast controllable opex for the next regulatory control period.[670]

Revised regulatory proposal

Ergon Energy did not accept the draft decision on this matter. Ergon Energy retained its forecast expenditure from its July 2009 regulatory proposal.[671]

Consultant review

PB reviewed Ergon Energy's revised regulatory proposal in relation to ICT overheads capex. This is discussed in section 7.4.4.6 of this decision. PB recommended a reduction of $2.8 million to Ergon Energy's ICT overheads capex program.[672]

AER considerations

The AER notes that Ergon Energy's expenditure in this category is delivered under its arrangement with SPARQ, for which Ergon Energy is charged a service fee. These service fees are treated as shared costs by Ergon Energy and are discussed in section 7.4.4.6 of this decision.

The AER notes that Ergon Energy allocated shared costs in accordance with its approved CAM, which results in approximately 23 per cent of ICT service fees being allocated to opex.

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669 Reasons for this are discussed further in chapter 7 of this final decision.

670 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 690–691.

671 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 170.

672 PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 57.

The AER requested Ergon Energy to model the proposed adjustment to the SPARQ capex program discussed in section 7.4.4.6 of this decision and Ergon Energy advised the resultant reduction in opex forecast was $0.8 million ($2009–10) for the next regulatory control period.[673]

AER conclusion

For the reasons discussed in section 7.4.4.6 of this decision, and as a result of the AER's analysis of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's forecast of ICT overheads reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed opex allocation of shared ICT costs by $0.4 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.

Solar Bonus Scheme

AER draft decision

In the draft decision, the AER did not accept Ergon Energy's proposal to consider the solar bonus scheme in the context of a pricing adjustment mechanism. The AER required Ergon Energy to provide a forecast of likely solar bonus tariff payments in the next regulatory control period, and included a specific nominated pass through event to enable any under or over recoveries of tariff payments to be recovered or returned to customers.

Revised regulatory proposal

Ergon Energy reiterated its preference for the solar bonus tariff payments to be treated in accordance with its regulatory proposal. However, it provided a forecast of solar bonus payments, estimated on the basis of actual and forecast data for 2009 and 2010, and applying growth rates approved by the AER in the context of the distribution determination for ETSA Utilities. Ergon Energy noted that the growth rates were considered appropriate as the schemes in South Australia and Queensland are essentially the same, and the two schemes commenced at the same time.

Ergon Energy forecast a total solar bonus payments of $16 million in the next regulatory control period. Ergon Energy's forecast is shown in table 8.8.

Table 8.8: Ergon Energy solar bonus tariff payments ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Solar Bonus Scheme	2.4	2.9	3.3	3.6	4.0	16.2

Source: Ergon Energy, *Revised regulatory proposal*, p. 197.

673 Ergon Energy, modelling response, 22 April 2010, PRP1028c, confidential.

AER considerations

The AER notes that Ergon Energy has based its forecast solar bonus scheme tariff payments on the basis of actual payments in 2009 and forecast data for 2010, and growth rates derived from the estimation process used by ETSA Utilities. ETSA Utilities' estimation process has been reviewed by the AER, and is a reasonable forecasting methodology. Based on the information provided by Ergon Energy in its revised regulatory proposal and in response to requests for further information, the AER considers that the approach Ergon Energy used to determine its forecast solar bonus scheme payments for the next regulatory control period is reasonable. The AER considers Ergon Energy's forecast of $16 million for solar bonus scheme tariffs payments for the next regulatory control period is reasonable.

AER conclusion

The AER maintains its position in the draft decision that differences between actual and forecast allowances for solar bonus scheme (feed–in tariff scheme) tariffs will be treated as a nominated pass through event for the next regulatory control period.

The AER's consideration of Ergon Energy's proposed feed–in tariff pass through event is set out at chapter 15 of this decision.

AER conclusion

Ergon Energy advised that the adjustment associated with other opex (excluding input cost escalation) results in a reduction of $39 million ($2009–10) to the forecast opex for the next regulatory control period.[674]

This amount is comprised of an adjustment to the revised regulatory proposal to take account of:

- $1.6 million for GSL payments
- $34 million for customer service opex
- $1.0 million for ICT projects (overhead)
- $2.6 million for demand management project management.

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's other opex forecast reasonably reflects the opex criteria, including the opex objectives. The AER considers reducing the other opex forecast by $39 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for the other opex forecast to comply with the NER. In coming to this view the AER has had regard to the opex factors.

[674] Ergon Energy, response to modelling request, 22 April 2010, confidential.

8.4.3 Smart meters

AER draft decision

The AER included a smart meter event as a nominated pass through event for the Qld DNSPs. The draft decision did not explicitly review any forecast expenditures related to smart meters.[675]

Revised regulatory proposals

Ergon Energy accepted the draft decision to include a smart meter event as a nominated pass through event.[676]

AER considerations

The AER is aware that there is considerable uncertainty regarding the implementation of smart meters in Queensland. Given the degree of uncertainty that currently exists, the AER considers that it is not reasonable to include smart meter expenditures in the forecast capex and opex allowances for the Qld DNSPs.

In response to a request from the AER, Ergon Energy advised that it had proposed amounts in its opex and capex forecasts for a smart meter pilot.[677] As part of its modelling request, the AER asked Ergon Energy remove any capex or opex related to smart meters contained in its revised regulatory proposal.

Ergon Energy advised that the adjustment for the removal of smart meter expenditures resulted in a reduction of $7 million ($2009–10) to its opex forecast.[678]

Energex advised that it did not include any forecast expenditures in relation to smart meters.

The AER notes that if, during the next regulatory period, the Qld DNSPs have smart meter obligations imposed upon them they may make a pass through application as a smart meter event is listed as a nominated pass through event in this decision (see chapter 15 of this decision).

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal and other information, the AER is not satisfied that Ergon Energy's proposed smart meter trial forecast opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing the opex forecast by $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.

[675] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 287.
[676] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 201.
[677] Ergon Energy, Response to modelling request, 22 April 2010, PRP1028c, confidential.
[678] Ergon Energy, Response to modelling request, 22 April 2010, PRP1028c, confidential.

8.4.4 Impact of growth capex

AER draft decision

The Qld DNSPs were requested to take into account the impact of reductions to the capex program prior to undertaking the specific modelling of amendments to the opex forecasts.[679]

In addition to this general request, and consistent with PB's recommendation, the AER reduced Ergon Energy's opex allowance to account for the reduction in maintenance activities that would result from the draft decision to reduce Ergon Energy's proposed growth capex program. This adjustment resulted in a reduction of $8.7 million ($2009–10) to the forecast preventative maintenance opex for the next regulatory control period.[680]

Revised regulatory proposal

Energex did not accept the AER's reduction to proposed growth capex, on the basis that it did not agree with the AER's conclusion that Energex's forecast of maximum demand was overstated. Energex resubmitted its original growth capex proposal, with the exception of the Traveston Dam pump load project, as discussed in section 7.4.3.2 of this decision.[681]

Ergon Energy did not agree with the draft decision to reduce its preventative maintenance opex forecast. Ergon Energy stated this was because in its revised regulatory proposal, it did not accept the draft decision on the reduction in its growth capex program. On this basis, Ergon Energy proposed that its original preventative maintenance forecast base be retained.[682]

AER considerations

The AER considers it is reasonable to expect some link between growth capex and opex. Other network service providers in Australia explicitly incorporate such a link in their opex modelling, and the escalator affects the forecasts for preventative, corrective and forced maintenance components of opex.[683]

The AER also notes that substantial reductions in the Qld DNSPs' forecast growth capex have been implemented, as discussed in chapter 7 of this decision.

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[679] AER, email Modelling request, Energex, 6 November 2009; and AER, email AER modelling request – Ergon, 6 November 2009.

[680] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 668.

[681] Energex, *Revised regulatory proposal*, January 2010, p. 14.

[682] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 151, 152, 212–214.

[683] ETSA Utilities, *Regulatory proposal*, July 2009, p. 149; Jemena, *Jemena electricity networks (Vic) Ltd regulatory proposal 2011–15*, 30 November 2009, p. 129; PowerCor, *Regulatory proposal 2011 to 2015*, 30 November 2009, p. 153; CitiPower, *Regulatory proposal 2011 to 2015*, 30 November 2009, p. 157; SP AusNet, *SPI Electricity Pty Ltd electricity distribution price review 2011–2015 – Regulatory proposal*, public version, November 2009, p. 212; ActewAGL, *ActewAGL distribution determination 2009–14, Regulatory proposal to the AER*, June 2008, p. 164; Country Energy, *Country Energy's electricity network regulatory proposal 2009–14*, June 2008, p. 48; EnergyAustralia, *Regulatory proposal*, June 2008, p. 112.

The AER requested the Qld DNSPs to remodel their forecast opex allowances using the revised estimates of network growth that incorporate the adjustments made to their growth capex forecast.[684]

Energex responded:[685]

> any reduction in growth capex for the 2010–15 regulatory control period will not have a material impact on the forecast 2010–15 opex as these assets are typically on a 5-year inspection and maintenance cycles; but may flow on to the forecast opex for the next regulatory control period.

Ergon Energy similarly stated:[686]

> … it cannot identify a link or driver [such that] a reduction in the capital expenditure forecast for the control period will result in a reduction in the operating expenditure forecast for the control period.

The Qld DNSPs did not identify a specific network growth escalator, and did not model an adjustment in their initial modelling responses.[687] The AER subsequently requested Energex model the reduction in opex resulting from the reduction to growth capex.[688] In response, Energex advised that the reduction as a result of the growth capex reductions would be $40 360 over the next regulatory control period.[689]

The AER notes the Qld DNSPs' statements that the impact of growth capex on preventative maintenance will be lagged, as many new assets (for example, poles) will not have inspections or maintenance scheduled until the completion of the inspection or maintenance cycle. Where the inspection cycle is greater than five years inspections will not occur within the next regulatory control period. Energex also stated that as growth capex has been reduced, there would need to be a related increase in opex to maintain older assets.[690] Ergon Energy also noted that while some visuals inspections may be undertaken when new assets are put into service the costs of these inspections would be immaterial.[691]

The AER has previously accepted that corrective maintenance and forced maintenance may be required on new assets, and theoretically could be required at any time after the installed assets starts providing services. This position is also supported by the Australian Competition Tribunal decision regarding defect maintenance for TransGrid.[692]

684 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 667–668.
685 Energex, email response, re:opex/capex interaction, 14 April 2010, confidential.
686 Ergon Energy, email response, Re: further points for clarification in the modelling, 13 April 2010, confidential.
687 Energex, modelling response, 9 April 2010, confidential; and Ergon Energy, modelling response 19 April 2010, PRP1023c, confidential.
688 AER, re:opex/capex interaction, 15 April 2010.
689 Energex, email response, opex/capex interaction, 21 April 2010, confidential.
690 Energex, email response, re:opex/capex interaction, 14 April 2010, confidential; Ergon Energy, email response, Re: further points for clarification in the modelling, 13 April 2010, confidential.
691 Ergon Energy, email response, Re: further points for clarification in the modelling, 13 April 2010.
692 Australian Competition Tribunal, *Application by EnergyAustralia and Others [2009]ACompT*, [305].

The AER therefore considers that irrespective of whether or not a network growth escalator is explicitly incorporated into the opex modelling, it is reasonable to assume that network growth has informed the Qld DNSPs' opex forecasts.

In reviewing the opex models provided by the Qld DNSPs, the AER was able to confirm an explicit network growth escalator was not applied.[693]

The AER notes Energex's opex modelling incorporates customer growth, rather than specific growth in asset population. However Energex identified that the reductions in growth capex may impact on two specific opex line items. Energex modelled the impact of a 20 per cent reduction in the growth capex for these two line items and estimated the reduction would total $40 000 ($2009–10) in the next regulatory control period.[694]

The AER has reviewed Energex's opex forecasting models and accepts that the impact of the reduction in growth capex is immaterial for Energex in the next regulatory control period.

The AER notes that Ergon Energy applied an asset population growth factor in the derivation of preventative, corrective and forced maintenance opex.[695] The AER considers that on the basis of information provided network growth has been used to develop Ergon Energy's opex forecasts.

Given that Ergon Energy was unable to model the impact of the reduction in growth capex on forecast opex, the AER derived its own estimate. The impact of the AER decision regarding growth capex forecasts represents a reduction in growth capex of around 24 per cent, in the next regulatory control period (see section 7.4.4.1 of this decision).[696] The AER reduced the annual population increase factors for each asset class in Ergon Energy's NARMCOS model by 24 per cent to explicitly account for the reduction in corporate initiated augmentation (growth) capex. The impact of the reduced asset population growth on preventative and corrective maintenance forecasts is a $9.0 million ($2009–10) reduction. The impact on forced maintenance was not included in this modelling as the revisions to forced maintenance discussed in section 8.4.2.3 already include an adjustment for network growth effects.

AER conclusion

The AER considers the impact of any changes of growth capex on the size of the Qld DNSPs' networks must be taken into account when forecasting opex requirements. However, the adjustment to Energex's forecast opex requirement has an immaterial impact on Energex's opex forecast.

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693 See Energex, *Revised regulatory proposal*, January 2010, Distribution and transmission operating programs 2006–2016, confidential, 1July 2009; and Ergon Energy, *Revised regulatory proposal*, January 2010, revised submission SC opex data model.

694 Energex, re:opex/capex interaction, 21 April 2010, confidential.

695 Ergon Energy, *Revised regulatory proposal*, January 2010, Revised submission NARMCOS data model.xls, Inputs sheet, for example cells B545, B520, B430.

696 The AER has estimated the percentage reduction taking into account corporate initiated growth capex only, and has not included any impact from customer initiated capital works.

For the reasons discussed, and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, PB's report and other material, the AER is not satisfied that Ergon Energy's network maintenance opex forecasts reasonably reflect the opex criteria, including the opex objectives. The AER considers reducing the network maintenance opex forecasts by $9.0 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.

8.4.5 Cost escalators

AER draft decision

The AER did not consider Energex's escalation rates for labour costs and materials costs were acceptable. As a result, Energex's forecast opex was reduced by $140 million.[697]

The AER did not consider Ergon Energy's application of a single escalation rate to internal and contract labour costs was appropriate because it diminished the commercial incentive for Ergon Energy to negotiate competitive wage outcomes and it did not differentiate between specialist and general labour resources.

The AER did not consider Ergon Energy's escalation rates for materials costs were acceptable because they did not reflect the most up to date market–based forecasts of future materials costs. Ergon Energy's forecast opex was reduced by $264 million ($2009–10).[698]

Revised regulatory proposals

Energex applied the AER's draft decision escalation rates and indicated that it expected the AER to update these to reflect data available at the time of the final decision.[699] Energex noted that it did not necessarily accept the rationale behind all of the AER's adjustments and that it would provide further comment on escalators in its submission to the AER.[700]

Application of the escalators proposed by the AER resulted in forecast opex for the next regulatory control period of $1617 million in Energex's revised proposal.[701]

Ergon Energy did not agree with certain aspects of the AER's approach to cost escalation, including adjustments in relation to how Ergon Energy applied escalators for real cost inputs as well as adjustments to the calculation of the real cost inputs.

Submissions

Energex provided a detailed proposal on cost escalation in its submission.[702] The approach to cost escalation proposed by Energex is discussed in more detail in appendix F.

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697 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 187.
698 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 192.
699 Energex, *Revised regulatory proposal*, January 2010, p. 18.
700 Energex, *Revised regulatory proposal*, January 2010, p. 1.
701 Energex, *Revised regulatory proposal*, January 2010, p. 20.

Application of the cost escalators proposed by Energex in its submission results in a revised forecast opex of $1670 million.[703]

Consultant review

Labour

The AER engaged Access Economics to provide an update on its growth forecasts for general state labour price indices (LPIs) and the electricity, gas and water (EGW) sector in NSW, Victoria, Queensland, South Australia, ACT and nationally.[704] Access Economics' forecasts are discussed in more detail in appendix F.

Access Economics general labour forecasts are set out in table 8.9 below.

Table 8.9: Access Economics real labour escalation rates for general labour and the EGW sector in Queensland.

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
General	0.4	0.5	0.2	0.4	0.9	1.4	1.5
EGW	1.1	1.1	1.0	0.9	1.3	1.5	1.6

Source: Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010, p. 69.

Materials

PB was not required to assess forecast rates of growth in input costs (this exercise has been undertaken by the AER and is described in detail in appendix F), but it was required to ensure that forecast changes in input costs were appropriately reflected in the cost escalation calculations performed by the Qld DNSPs in forecasting opex.

PB reviewed the cost weightings associated with Energex's proposed new materials cost escalator.

PB noted that SKM established the cost input weightings by applying a set of expenditure based category-level weightings within its database to Energex's asset categories. In order to assess these weightings, PB calculated a comparable set of weightings based on its understanding of DNSPs' project costs and components.[705]

PB considered that its estimates of component weightings were sufficiently similar to those developed by SKM to conclude that the weightings were reasonable and suitable for use in the forecasting of Energex's opex.[706]

PB reviewed Ergon Energy's response to PB's original recommendation to use the same CPI to inflate and deflate values in its cost escalation process. PB concluded that

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[702] Energex, *Submission on Draft Determination*, February 2010.
[703] Energex, email response, AER.EGX.RP.04, 5 March 2010, confidential.
[704] Access Economics, *Forecast growth in labour costs: March 2010 report,* 16 March 2010.
[705] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 5.
[706] PB, *Review of Energex's revised regulatory proposal*, April 2010, p. 6.

Ergon Energy should use the same inflation data to inflate and deflate real and nominal values.[707]

AER considerations

The details of the AER's assessment of the costs escalators proposed by the Qld DNSPs are set out in Appendix F of this decision.

Labour

The AER is satisfied that Access Economic's methodology for forecasting labour costs growth is robust given the application of its formal econometric modelling approach.[708]

The AER considers that union collective agreement (UCA) rates should not automatically be reflected within escalation rates for the next regulatory control period and these rates do not provide a realistic expectation of the DNSPs' labour costs.

The AER also considers that internal labour cost escalators should not be applied to contract labour costs because contractors do not form part of the internal workforce to which awards generally apply and the proportions of technical and general labour in the internal and contract labour forces of the DNSPs differ.

Construction costs

The AER considers that to develop a robust forecast it is appropriate to update the forecast construction cost escalators using the most recent data. The AER therefore considers it appropriate to apply the updated construction cost forecasts from the Construction Forecasting Council.[709]

Materials

The AER considers that the method adopted by the Qld DNSPs, with the exception of the trade weighted index (TWI) component, provides a realistic expectation of the real materials costs required for the Qld DNSPs to achieve the capex objectives in the next regulatory control period.

The AER does not accept inclusion of the TWI in the cost escalation proposed by the Qld DNSPs because it recognises TWI related cost increases prior to the regulatory control period but provides no possibility of capturing cost decreases during the regulatory control period.

AER conclusion

Table 8.10 sets out the AER's conclusion on Energex's real cost escalators over the next regulatory control period. More detailed information on the AER's assessment is in appendix F of this decision.

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[707] PB, *Review of Ergon Energy's revised regulatory proposal*, April 2010, p. 52.

[708] See AER, *Draft decision, Queensland draft distribution determination,* November 2009, p. 605 for an overview of the AEM approach.

[709] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 599.

Table 8.10: AER conclusions on Energex's real cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Aluminium	–18.76	–6.96	23.00	–1.20	0.40	–2.62	–3.58
Copper	–27.33	17.42	20.03	–5.42	–4.19	–7.48	–8.63
Steel	7.09	–28.29	33.03	1.00	0.80	–2.29	–3.25
Crude oil	–17.34	–3.69	25.80	–2.97	0.24	–1.74	–2.46
Exchange rates	0.744	0.856	0.721	0.738	0.725	0.728	0.738
Inflation rate	1.46	3.00	2.50	2.75	2.50	2.50	2.50
Materials	–5.05	–5.31	10.71	–0.43	0.11	–1.20	–1.67
Land and easements	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Construction	–0.09	1.90	0.31	1.10	2.66	2.51	0.81
Internal labour	0.12	2.22	0.20	0.86	1.27	1.52	1.63
Contract labour	0.99	0.97	0.83	0.78	1.22	1.50	1.61

Note: AER analysis, except Energex's materials cost escalator, which is a composite based on materials inputs listed in this table. Source: Energex, *Response to AER modelling request (Energex FD)*, 9 April 2010, confidential.

The impact of the application of the AER's input cost escalators on Energex's forecast opex is illustrated in table 8.11.

Table 8.11: Impact of the application of AER input cost escalators on Energex's opex forecasts ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Impact of AER's revised escalators, modelled by Energex	–10.5	–9.4	–9.4	–7.9	–5.9	–43.1

Note: Totals may not add due to rounding.

Table 8.12 sets out the AER's conclusion on Ergon Energy's real cost escalators over the next regulatory control period. More detailed information on the AER's assessment is in appendix F of this decision.

Table 8.12: AER conclusions on Ergon Energy's real cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Aluminium	–18.76	–6.96	23.00	–1.20	0.40	–2.62	–3.58
Copper	–27.33	17.42	20.03	–5.42	–4.19	–7.48	–8.63
Steel	7.09	–28.29	33.03	1.00	0.80	–2.29	–3.25
Crude oil	–17.34	–3.69	25.80	–2.97	0.24	–1.74	–2.46
Exchange rates	0.744	0.856	0.721	0.738	0.725	0.728	0.738
Inflation rate	1.46	3.00	2.50	2.75	2.50	2.50	2.50
Commercial land	4.20	5.50	5.40	5.00	5.00	5.40	5.80
Rural land	6.80	8.10	8.00	7.60	7.60	8.00	8.40
Construction	–0.09	1.90	0.31	1.10	2.66	2.51	0.81
Internal labour	0.18	1.83	0.21	0.75	1.19	1.50	1.60
Contract labour	1.15	1.08	0.98	0.88	1.29	1.53	1.64

Source: AER analysis.

The impact of the application of the AER's input cost escalators on Ergon Energy's forecast opex is illustrated in table 8.13.

Table 8.13: Impact of the application of AER input cost escalators on Ergon Energy's opex forecasts ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Impact of AER's revised escalators, modelled by Ergon Energy	–5.69	–8.44	–10.02	–10.64	–10.64	–45.44

Note: Totals may not add due to rounding.

8.4.6 Self insurance

Energex

AER draft decision

The AER applied a principled approach to assessing the Qld DNSPs' self insurance allowances within the draft decision. On this basis the AER rejected Energex's proposed self insurance premiums. In particular the AER rejected Energex's $8.4 million storm catastrophe self insurance allowance, and considered that an efficient premium for storm catastrophe self insurance could not be reasonably determined. Further, the AER rejected Energex's $6.3 million public liability self insurance allowance and considered that the most appropriate premium was $37 640 over the next regulatory control period. The AER also rejected Energex's proposed self insurance premium of $0.4 million in relation to retailer credit risk and considered that an efficient premium could not be reasonably determined.[710]

Revised regulatory proposal

Energex sought to have storm catastrophe and retailer credit risk included as specified nominated pass through events.[711] The AER's detailed assessment of these proposed pass through events is set out in chapter 15.

Energex resubmitted its original proposal in relation to public liability risks of $6.3 million. Energex considered that the AER's determination of a substitute public liability premium was 'fundamentally flawed'.[712] Energex provided an external quote to lower the deductibles on its public liability policy with its revised regulatory proposal.[713]

AER considerations

The AER's detailed consideration of Energex's revised regulatory proposal in relation to self insurance is set out in appendix H.

Storm catastrophe

While the AER notes that Energex has sought to include storm catastrophe as a defined nominated pass through event, rather than seeking to self insure for these events, the AER reiterates its draft decision, which considered that storm catastrophe losses are not suitable for self insurance.

Retailer credit risk

The AER assessed Energex's proposal to address retailer credit risk losses via the cost pass through mechanism in chapter 15 of this decision.

Public liability

The AER rejected Energex's public liability self insurance premium. Using the external quote provided by Energex as a maximum efficient benchmark, the AER considered that $4.75 million over the next regulatory control period was the appropriate public liability self insurance opex allowance for Energex.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Energex's revised regulatory proposal and other material, the AER is not satisfied that Energex's proposed self insurance allowance reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Energex's proposed self insurance opex by $1.5 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 and the self insurance principles outlined in appendix H.

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710 AER, *Draft decision, Queensland draft distribution determination*, November 2009, appendix K.

711 Energex, *Revised regulatory proposal*, January 2010, p. 23.

712 Energex, *Revised regulatory proposal*, January 2010, pp. 24–25.

713 Energex, *Revised regulatory proposal*, January 2010, Appendix 4.1, Willis Australia Non–binding public liability premium estimate – December 2009, confidential.

Table 8.14 summarises the proposed self insurance allowances and the AER's draft decision.

Table 8.14: AER's conclusion on Energex's self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed	1.2	1.2	1.3	1.3	1.3	6.3
AER adjustments	0.2	0.2	0.3	0.3	0.3	1.5
Total self insurance	0.9	0.9	0.9	0.9	0.9	4.7

Note: Totals may not add due to rounding.

Ergon Energy

AER draft decision

The AER applied a principled approach to assessing the Qld DNSPs' self insurance allowances within the draft decision. On this basis, the AER rejected Ergon Energy's proposed self insurance premiums. In particular the AER rejected Ergon Energy's $5.3 million storm catastrophe self insurance allowance, and considered that an efficient premium for storm catastrophe self insurance could not be reasonably determined. Further, the AER rejected Ergon Energy's $16.3 million public liability self insurance allowance and considered that the most appropriate premium was $3218 over the next regulatory control period.[714]

Revised regulatory proposal

Ergon Energy did not accept the AER's draft decision and resubmitted its original self insurance proposal of $21.5 million. Ergon Energy considered that the AER's proposed approach to handling storm catastrophe costs was untenable, and that it should be compensated for costs of storms that fall between the upper demarcation of the maintenance budget and the cost pass through materiality threshold.[715] Additionally, Ergon Energy considered that the AER's derivation of a substitute public liability premium was 'fundamentally flawed'. Ergon Energy included an external quote to lower the deductibles on its public liability policy with its revised regulatory proposal.[716]

AER considerations

The AER's detailed consideration of Ergon Energy's revised regulatory proposal in relation to self insurance is set out in appendix H. The AER noted that Ergon Energy did not have any data on a storm that would be considered a storm catastrophe as defined by Finity, its self insurance consultant. The AER also considers that a DNSP may fund these types of losses via a prudent reprioritisation of the opex pool of funds.

714 AER, *Draft decision, Queensland draft distribution determination*, November 2009, Appendix K.

715 Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP968c, Finity, Response to AER.

716 Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP968c, Finity, Response to AER, p. 9.

The AER also considered that the geographic spread of Ergon Energy's assets may be a considerable mitigating factor against storm catastrophe risks, and this factor may partly be why Ergon Energy has not experienced a storm catastrophe event as defined by Finity. In addition, the AER noted that any capex associated with emergency asset replacement would be added to the asset base, and that the assets destroyed would still continue to earn a return even though they would not be providing a service. The AER considered that an efficient self insurance premium for storm catastrophe events could not be estimated and no self insurance allowance was provided.

The AER also rejected Ergon Energy's public liability self insurance premium, and, using the external quote provided by Ergon Energy as a maximum efficient benchmark, considered that $3.75 million over the next regulatory control period was the appropriate public liability self insurance premium. In addition, in accordance with the efficiency benefit sharing scheme, the AER removed 'business as usual', attritional liability costs and reclassified these costs as controllable opex.

AER conclusion

For the reasons discussed and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal, and other material, the AER is not satisfied that Ergon Energy's forecast self insurance opex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's self insurance opex by $17.8 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. This reduction includes the reclassification of $11.7 million of attritional public liability losses to the controllable opex category. In coming to this view the AER has had regard to the opex factors and the self insurance principles outlined in appendix H.

Table 8.15 summarises the proposed self insurance allowance and the AER's decision.

Table 8.15: AER conclusion on Ergon Energy's self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposed	4.2	4.2	4.3	4.4	4.5	21.5
AER adjustments	3.4	3.4	3.5	3.6	3.7	17.8
Attritional liability reclassified as controllable opex	2.2	2.	2.4	2.4	2.5	11.7
Total self insurance	0.7	0.7	0.7	0.7	0.7	3.7

Note: Totals may not add due to rounding.

8.4.7 Debt raising costs

AER draft decision

The AER determined an allowance of $25.3 million and $22.0 million in relation to benchmark debt raising costs for Energex and Ergon Energy respectively. This was calculated on the basis of an allowance of 9.0 basis points per annum (bppa) for direct debt raising costs and no allowance for the indirect debt raising costs.[717]

Revised regulatory proposal

Energex acknowledged the draft decision reducing its proposed allowance on debt raising costs for the next regulatory control period. It included the draft decision allowance as part of its forecast opex in its revised regulatory proposal.[718]

Ergon Energy did not accept the draft decision reducing its proposed debt raising costs and maintained the position in its regulatory proposal. However, for modelling purposes in its revised regulatory proposal, Ergon Energy used the AER's substituted costs in the draft decision.[719] Ergon Energy's proposed debt raising allowance is shown in table 8.16.

Table 8.16: Qld DNSPs' revised debt raising allowances ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	4.1	4.7	5.1	5.6	6.1	25.6
Ergon Energy	3.8	4.2	4.7	5.2	5.7	23.7

Source: Energex, *Revised regulatory proposal*, January 2010, PTRM, input sheet, confidential.
Ergon Energy, *Revised regulatory proposal*, January 2010, PTRM, input sheet, confidential.

AER considerations

The AER notes that Ergon Energy did not accept the draft decision in relation to debt raising costs and maintained the position outlined in its regulatory proposal. In its regulatory proposal, Ergon Energy proposed an allowance of 15.5 bppa comprising:[720]

- 12.5 bppa for direct debt raising costs
- 3.0 bppa for indirect debt raising costs.

The AER notes that Ergon Energy has not provided any new information in response to the draft decision to support its revised regulatory proposal on these matters.

As noted in the draft decision, 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

[717] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 168–171.
[718] Energex, *Revised regulatory proposal*, January 2010, p. 25.
[719] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 173–174.
[720] Ergon Energy, *Regulatory proposal*, July 2009, p. 307.

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.[721] The AER confirms its draft decision and does not consider that the allowance for debt raising costs should include indirect debt raising costs.

Consistent with the draft decision and in accordance with the approach based on the ACG methodology,[722] the AER updates the benchmark direct debt raising costs allowance using the nominal vanilla weighted average cost of capital (WACC) (used to amortise up-front costs) of 9.72 per cent. The AER has also updated the size of the benchmark bond issue to correctly equal the median domestic bond issue size of the five year rolling window. This reduces the benchmark bond issue from $263 million to $250 million.[723]

This results in the debt raising costs shown in table 8.17.

Table 8.17: Direct debt raising costs with a nominal vanilla WACC of 9.72 per cent

Fee	Explanation	1 Issue	3 Issues	7 Issues	18 Issues	19 Issues
Amount Raised	Multiples of median MTN ($250m)	$250 million	$750 million	$1 750 million	$4 500 million	$4 750 million
Gross underwriting fee	Median gross underwriting spread, up front per issue	7.24	7.24	7.24	7.24	7.24
Legal and roadshow	$115K upfront per issue	0.74	0.74	0.74	0.74	0.74
Company credit rating	$50K per annum	2.00	0.67	0.29	0.11	0.11
Issue credit rating	4 basis points up front per issue	0.64	0.64	0.64	0.64	0.64
Registry fees	$3.5K up front per issue	0.14	0.14	0.14	0.14	0.14
Paying fees	$4/$1million per annum	0.04	0.04	0.04	0.04	0.04
Total	Basis points per annum	10.8	9.5	9.1	8.9	8.9

Source: ACG, Bloomberg, AER analysis.

Energex has an opening RAB of $7.9 billion. On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of Energex's opening RAB is around $4.7 billion. Based on the ACG methodology, this debt size would require around 19 bond issues. As such, the AER considers that an allowance of 8.9 bppa for debt raising costs is a reasonable benchmark for Energex. Using the PTRM, this

721 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 737.
722 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 170.
723 AER, *Final decision, South Australian distribution determination*, May 2010, section 8.4.6.

benchmark is multiplied by the debt component of Energex's opening RAB to derive an average allowance of $5.0 million per annum ($2009–10).

Ergon Energy has an opening RAB of $7.1 billion. On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of Ergon Energy's opening RAB is around $4.3 billion. Based on the ACG methodology, this debt size would require around 18 bond issues. As such, the AER considers that an allowance of 8.9 bppa for debt raising costs is a reasonable benchmark for Ergon Energy. Using the PTRM, this benchmark is multiplied by the debt component of Ergon Energy's opening RAB to derive an average allowance of $4.4 million per annum ($2009–10).

AER conclusion

The AER's conclusion on benchmark debt raising costs for the Qld DNSPs over the next regulatory control period is set out in table 8.18. The AER considers that setting the benchmark debt raising costs for Energex and Ergon Energy to $25 million and $22 million ($2009–10) respectively for the next regulatory control period, consistent with the approach set out in the draft decision, results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and reflects 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 8.18: AER conclusion on Qld DNSP's debt raising costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	4.1	4.6	5.0	5.5	5.9	25.1
Ergon Energy	3.7	4.1	4.4	4.8	5.1	22.1

Note: Total may not add due to rounding.

8.4.8 Equity raising costs

AER draft decision

The AER included an allowance of $36.8 million and $11.9 million ($2009–10) in relation to benchmark equity raising costs for Energex and Ergon Energy respectively. These amounts excluded indirect equity raising costs, and the impact of capital contributions on the tax payable in the cash flow analysis. The AER included the equity raising costs in the Qld DNSPs' RABs and amortised these costs over a standard asset life, based on a weighted average life of all assets in their respective RABs.[724]

Revised regulatory proposal

Energex acknowledged the draft decision allowance on equity raising costs for the next regulatory control period. It also acknowledged the draft decision to transfer equity raising costs from forecast opex to the RAB. Energex's revised regulatory proposal included the allowance for equity raising costs in the RAB. Energex noted

[724] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 173–176.

the applicable asset life will be recalculated in accordance with the AER's methodology and adjustments made in the revised regulatory proposal.[725]

Energex submitted that the assumed payout ratio for dividend imputation credits used in the cash flow model for estimating equity raising costs should be 71 per cent, consistent with its proposed estimate of gamma.

Ergon Energy did not accept the draft decision reducing its proposed equity raising costs and maintained the position in its regulatory proposal. It also did not accept the draft decision approach of amortising equity raising costs. However, for modelling purposes in its revised regulatory proposal, Ergon Energy used the AER's substituted costs in the draft decision and amortised these costs over the life of the RAB.[726]

AER considerations

Energex submitted that its equity raising costs allowance should be set assuming a 71 per cent payout ratio for imputation credits in the cash flow model, consistent with its proposed estimate for the payout ratio in estimating gamma.[727] As discussed in chapter 9 of this decision and taking account of the advice of its consultants, the AER considers that an assumed imputation credit payout ratio of 100 per cent is consistent with the PTRM framework and the Officer WACC framework. Therefore, the AER confirms its draft decision that the assumed payout ratio for imputation credits of 100 per cent be applied in the cash flow model for estimating equity raising cost for the Qld DNSPs.

The AER notes that Ergon Energy did not accept the draft decision in relation to equity raising costs and maintained the position outlined in its regulatory proposal. In its regulatory proposal, Ergon Energy proposed:

- indirect equity raising costs of 3.3 per cent of the total amount raised through seasoned equity offerings (SEOs)[728]

- direct equity raising costs of 4.5 per cent of the total funds raised through SEOs and 2 per cent of funds raised through dividend reinvestment plans.[729]

The AER notes that Ergon Energy has not provided any new information in response to the draft decision to support its revised regulatory proposal on these matters.

As noted in the draft decision, 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 reflects the efficient costs of achieving the opex objectives and the costs that a prudent operator in the circumstances of the relevant DNSP would require to

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725 Energex, *Revised regulatory proposal*, January 2010, p. 26.
726 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 173–174.
727 Energex, *Revised regulatory proposal*, January 2010, p. 26.
728 Ergon Energy, *Regulatory proposal*, July 2009, p. 307.
729 Ergon Energy, *Regulatory proposal*, July 2009, p. 307.

achieve the objectives.[730] The AER confirms its draft decision and does not consider that the allowance for equity raising costs should include indirect equity raising costs.

Consistent with the draft decision, the AER considers the best estimate of the direct costs of raising funds through dividend reinvestment plans is 1 per cent of the total funds raised using this method. This is based on the AER's analysis of recent dividend reinvestment plans in Australia, as outlined in the draft decision.[731] The AER also considers the best estimate of the direct costs of SEOs is 3 per cent of the total funds raised using SEOs. This is based on the AER's analysis of recent SEOs in Australia, as outlined in the draft decision.[732]

Amortisation of costs

The AER notes that while Ergon Energy did not accept the draft decision to amortise equity raising costs, it applied this approach in its revised regulatory proposal. The AER's consideration of amortising equity raising costs and its assessment of the appropriate standard life is discussed in chapter 10 of this decision.

AER conclusion

The AER's conclusion on benchmark equity raising costs for the Qld DNSPs over the next regulatory control period is set out in table 8.19. The AER considers that setting the benchmark equity raising costs for Energex and Ergon Energy to $33 million and $14 million ($2009–10) respectively for the next regulatory control period, consistent with the approach set out in the draft decision, results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and reflects 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.

[730] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 767.
[731] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 775.
[732] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 775.

Table 8.19: AER conclusion on benchmark equity raising cost ($m, nominal)

Cash flow analysis	Energex	Ergon Energy	Notes
Dividends	1301.8	886.7	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	390.5	266.0	30% of dividends paid
Cost of dividend reinvestment plans	3.9	2.7	Dividends reinvested multiplied by benchmark cost (1%)
Capex funding requirement	5703.7	4681.1	This is the forecast capex funding requirement (not the capex value that includes a half year WACC adjustment)
Debt component	3292.1	2489.1	Set to equal 60% of RAB increase (not capex)
Equity component	2411.6	2192.0	Residual of capex funding requirement and debt component
Retained cash flows available for reinvestment	1376.7	1770.9	Includes dividends reinvested
External equity requirement	1034.9	421.2	Equal to equity component less retained cash flows
External equity raising cost	31.0	12.6	External equity requirement multiplied by benchmark direct cost (3%)
Total equity raising cost	35.0	15.3	Sum of dividend reinvestment plan cost and external equity raising cost
Total equity raising cost ($2009–10)	32.7	14.2	To be added to the RAB at the start of the next regulatory control period

The amounts specified in table 8.18 have been amortised over the weighted average standard life of the Qld DNSPs' RABs for the purposes of providing the equity raising cost allowance associated with the forecast capex over the next regulatory control period.[733]

8.4.9 Interest rate hedging costs

AER draft decision

The AER did not agree with the Qld DNSPs' categorisation of the claims for interest rate hedging costs as opex. The AER considered this to be a claim for a higher cost of capital.[734]

[733] For Energex a standard life of 46.1 years for amortisation purposes, consistent with Energex's weighted average asset life, has been applied. For Ergon Energy a standard life of 48.0 years for amortisation purposes, consistent with Ergon Energy's weighted average asset life, has been applied.

[734] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 182.

The AER did not approve an allowance for interest rate hedging costs on new borrowings for the Qld DNSPs. The AER considered that the proposal would represent a fundamental change in the regulatory framework administered by the AER.[735]

The AER considered that insufficient evidence had been provided by the Qld DNSPs to support their claims and they had not demonstrated:[736]

- the AER's cost of capital benchmark was not appropriate for these businesses
- sufficient compensation was not currently provided to these businesses via the regulatory framework
- if interest rate hedging was not undertaken, it would adversely impact on the benchmark BBB+ credit rating and 60:40 gearing ratio.

Revised regulatory proposals

The Qld DNSPs did not re–submit claims for an interest rate hedging cost allowance on new borrowings. However, the Qld DNSPs commented on the draft decision.

Energex

Energex acknowledged the draft decision to reject an allowance for interest rate hedging costs. It noted the AER's position that approval of such an allowance may represent a fundamental change in the regulatory framework administered by the AER. However, Energex considered the AER's reasoning for rejecting the proposal did not fully consider the merits of the issue.[737]

Energex confirmed it would not be making a further proposal in relation to hedging costs, as it did not have any new evidence. However Energex indicated it would provide a submission to the AER, confirming it did not agree with the AER's reasons for rejecting the proposal and setting out concern that some arguments were not fully considered.[738]

Ergon Energy

Ergon Energy submitted that it did not accept the draft decision, and that it maintained its position in its regulatory proposal. It stated that for modelling purposes it would use the AER's substituted costs, being a zero allowance.[739]

Following a request from the AER for clarification on these statements, Ergon Energy confirmed that it would not submit any further material/arguments in relation to interest rate hedging costs.[740]

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[735] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 180.
[736] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 180–182.
[737] Energex, *Revised regulatory proposal*, January 2010, p. 25.
[738] Energex, *Email to AER – hedging costs*, AER.EGX.RP.1.6, 5 February 2010, confidential.
[739] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 174.
[740] Ergon Energy, *Email to AER – hedging costs*, AER.ER.RRP.13, 15 February 2010.

Submissions

The AER received a submission from Energex on interest rate hedging costs,[741] which included a report from Strategic Finance Group Consulting (SFG). Energex had concerns with two aspects of the draft decision:[742]

- the categorisation of the claims
- the assessment of the need to hedge interest rate risk.

Categorisation of claims

Energex disagreed that its hedging cost claims should be categorised as cost of capital issues rather than opex, restating that interest rate hedging costs represent efficient costs of achieving the opex objectives. Energex set out concerns with the legal and economic aspects of the draft decision.[743]

Legal issues

Energex stated it is reasonable for hedging costs to be estimated over the same averaging period used to set the risk–free rate and debt risk premium, and it was not aware of anything in the NER to the contrary.[744]

Means for allowing hedging costs

Energex and SFG submitted that a hedging cost allowance was no different to insurance costs, which are included as part of opex and not in the WACC.[745]

SFG also disagreed with the AER's statement that the claims for interest rate hedging costs must either be a risk premium allowance for risk currently borne by equity providers and/or an allowance for higher expected costs (required return) on debt in the future. It submitted:[746]

- the cash flow required to hedge interest rate risk can be estimated
- hedging interest rate risk was is a common and prudent business practice
- once the risk is hedged, providers of capital require no additional expected return in relation to it (interest rate risk should and has been hedged by Energex so the providers of capital are not exposed to the risk).

The need to hedge interest rate risk

Energex expressed concern with some of the AER's statements about rejecting the need for an allowance for interest rate hedging, particularly the rejection of the information originally submitted by SFG. It claimed the information showed that a

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741 Energex, *Submission on draft determination*, February 2010, pp. 19–20.
742 Energex, *Submission on draft determination*, February 2010, SFG, *Appendix 3 to Energex submission on draft determination*, February 2010, pp. 1–6.
743 Energex, *Submission on draft determination*, February 2010, p. 19.
744 Energex, *Submission on draft determination*, February 2010, p. 20.
745 Energex, *Submission on draft determination,* February 2010, p. 19.
746 Energex, submission on draft determination, February 2010, Appendix 3 – SFG, p. 3.

DNSP could be exposed to a credit rating downgrade if interest rates moved materially.[747]

Maintenance of credit rating without hedging
SFG was concerned that the AER was implying that the assumed BBB+ credit rating would be maintained irrespective of any deterioration in the key financial ratios that form the basis of Standard and Poor's assessment of credit ratings. It considered the question should be whether an unhedged change in interest rates would cause the key financial ratios to deteriorate sufficiently to put the BBB+ credit rating in jeopardy.[748] Energex and SFG stated their original submission showed that a DNSP could in fact be exposed to a credit rating downgrade if interest rates moved materially.[749] SFG was unclear why its evidence was insufficient, or what other evidence, if any, could be presented.[750]

Energex considered that the AER had not presented evidence for its assumption that because Energex has relatively stable cash flows, its credit rating was unlikely to be changed even with lower cash flow coverage and higher gearing.[751]

Whether DNSPs would hedge if compensated or not
SFG considered that it is likely that a DNSP would hedge regardless of whether it received compensation, as it is a prudent business practice, but that the same could be said of all insurances. It stated that the relevant question was whether the insurance premium was reasonable and prudent for the benchmark DNSP.[752]

SFG submitted that the AER's statement that a DNSP may choose not to hedge regardless of any allowance could also be said of any allowance. It submitted that the relevant question was whether hedging costs are prudent expenses, not whether the DNSP may elect not to incur the expense even if it is included in the opex.[753]

Equity investors already compensated for risk
SFG expressed concern with the AER's statement that interest rate risk is a risk for which equity investors in these firms already appear to be compensated. It submitted that the AER suggested that the estimated equity beta includes an allowance for the risk that interest rates may increase (thereby deteriorating the firm's key financial ratios and threatening its credit rating). It suggested the argument is based on the supposition that the comparable firms on which the equity beta estimate is based do not hedge and are exposed to the same interest rate risk that would apply to the benchmark DNSP if it also did not hedge. SFG submitted it is standard for the comparable firms to hedge this type of risk so that they do not remain exposed to changes in interest rates. Consequently the beta estimates for these comparable firms are not affected by unhedged interest rate risks.[754]

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[747] Energex, *Submission on draft determination*, February 2010, p. 20.
[748] Energex, *Submission on draft determination*, February 2010, *Appendix 3* – SFG, p. 4.
[749] Energex, *Submission on draft determination*, February 2010, *Appendix 3* – SFG, p. 4.
[750] Energex, *Submission on draft determination*, February 2010, *Appendix 3* – SFG, p. 5.
[751] Energex, *Submission on draft determination*, February 2010, *Appendix 3* – SFG, p. 20.
[752] Energex, *Submission on draft determination*, February 2010, Appendix 3 – SFG, p. 5.
[753] Energex, *Submission on draft determination*, February 2010, Appendix 3 – SFG, p. 5.
[754] Energex, *Submission on draft determination*, February 2010, Appendix 3 – SFG, p. 6.

AER considerations

The AER notes it has not had before it a building block proposal from the Qld DNSPs comprising of an opex forecast for an allowance for interest rate hedging costs on new borrowings in the next regulatory control period, nor a sufficiently concrete methodology upon which a forecast expenditure could be developed. Nevertheless, the AER assessed the merits of the claims in the form advanced by the Qld DNSPs. The draft decision disallowed an allowance for interest rate hedging costs, on a number of economic grounds and cited insufficient evidence in support of the economic merits of the claims.

In their revised regulatory proposals, the Qld DNSPs did not resubmit their claims, therefore the AER does not have a proposed forecast opex or methodology to assess.

Energex, as part of a subsequent submission to the AER, advanced a number of concerns with the draft decision. The AER has considered Energex's concerns and acknowledges that it questions a number of the AER's conclusions in the draft decision, in particular the extent of hedging undertaken by the comparator firms used to set the equity beta used in the WACC review.[755] While noting the conceptual and practical complexity of these questions, the AER considers that the submission has not advanced on the revised regulatory proposal in actually submitting specific forecast opex amounts for interest rate hedging costs or a sufficiently concrete methodology for determining interest rate hedging costs.

The AER considers that because neither of the Qld DNSPs' proposed forecast opex amounts for interest rate hedging costs or sufficiently concrete methodologies for determining interest rate hedging costs, the Qld DNSPs' proposed opex has been assessed on the basis that costs for interest rate hedging are excluded from the proposed forecast opex. Therefore the AER confirms its draft decision of not approving an allowance for interest rate hedging costs.

AER conclusion

The AER does not approve an opex allowance for interest rate hedging costs on new borrowings for the Qld DNSPs in the next regulatory control period.

8.4.10 Benchmarking

AER draft decision

The AER conducted a simple ratio analysis for a variety of opex ratios, which compared forecast allowances over the next regulatory control period with actual and forecast regulatory allowances from 2007–08.

The AER also undertook regression analysis, which was conducted using actual opex from 2007–08.[756] [757]This analysis was informed by benchmarking work that has been

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755 AER, *Final decision, Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, 1 May 2009.

756 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 624–626 and pp. 659–662.

757 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 199–201.

undertaken by Ofgem in the United Kingdom, and by Wilson Cook for the AER.[758] This work has a number of specific limitations.

The AER also considered benchmarking work undertaken by consultants on behalf of the Qld DNSPs.[759]

The AER considered the opex ratio analysis and regression analysis met the benchmarking requirements of clauses 6.5.7(e)(4) of the NER.

Revised regulatory proposal

Ergon Energy provided reports from Benchmark Economics and Huegin addressing the issue of benchmarking.

Submissions

The Energy Consumers Coalition of South Australia (ECCSA), the EUAA, Cement Australia and EnergyAustralia made submissions regarding benchmarking.

AER considerations

The AER reviewed the issues raised in submissions and provided further information on benchmarking in appendix G of this decision.

AER conclusion

As required under clauses 6.5.6(e) and 6.5.7(e) of the NER, the AER has had regard to benchmark expenditure (opex and capex) that would be incurred by an efficient DNSP over the regulatory control period in coming to its conclusions on the forecast opex and capex allowances of the Qld DNSPs.

The AER will continue to develop more robust benchmarking techniques, and improve the quality of available information in order to expand its use of benchmarking in evaluating opex and capex proposals.

8.5 AER conclusion

Energex

The AER has reviewed Energex's proposed forecast opex allowance and, for the reasons set out in this chapter, is not satisfied that the proposed forecast opex allowance reasonably reflects the opex criteria under clause 6.5.6(c) of the NER, including the opex objectives. 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 opex:

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[758] Wilson Cook, *Review of proposed expenditure of ACT & NSW electricity DNSPs: Volume 1, Main Report*, October 2008, pp. 17–25; and Wilson Cook, *Review of proposed expenditure of NSW & ACT electricity DNSPs: EnergyAustralia's submissions of January and February 2009*, March 2009, pp. 13–15.

[759] AER, *Draft decision, Queensland draft distribution determination*, November 2009, appendix I, pp. 624–625 and pp. 659–660.

- does not reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives
- does not reflect the efficient costs that a prudent operator in the circumstances of Energex would require to achieve the opex objectives
- 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 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 opex for Energex is $1634 million, as set out in table 8.20.

Table 8.20: AER conclusion on Energex's total opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex's proposed forecast opex[a]	314.8	317.2	324.8	332.3	327.6	1616.7
Energex's amended forecast opex[b]	325.8	328.5	336.3	342.6	336.4	1669.7
Adjustments to controllable opex	–0.7	–0.7	–0.8	–0.8	–0.9	–4.0
Adjustments to self insurance	–0.2	–0.3	–0.3	–0.3	–0.4	–1.5
Adjustment to debt raising	–0.0	–0.1	–0.2	–0.2	–0.3	–0.8
Adjustment to input cost escalators	–10.5	–9.4	–9.4	–7.9	–5.9	–43.1
Adjustment for overheads removed in capex adjustments	3.2	1.5	2.7	3.0	3.5	13.9
Total AER approved opex allowance	317.6	319.4	328.3	336.3	332.5	1634.1

Note: Totals may not add due to rounding.

(a) The revised regulatory proposal forecasts were derived using the AER's escalators as outlined in the draft decision. Excludes proposed equity raising costs. The AER will allow Energex to amortise a total amount of $32.7 million ($2009–10) in benchmark equity raising costs for the next regulatory control period.

(b) The amended opex forecast is derived using Energex's input cost escalators, as outlined in its submission to the AER.

Ergon Energy

The AER has reviewed Ergon Energy's proposed forecast opex allowance and, for the reasons set out in this chapter, 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 opex:

- does not reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives
- does not reflect the efficient costs that a prudent operator in the circumstances of Ergon Energy would require to achieve the opex objectives
- 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 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 controllable opex for Ergon Energy is $1801 million, as set out in table 8.21.

Table 8.21: AER conclusion on Ergon Energy's total opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy's proposed forecast opex[a]	372.7	387.7	389.2	388.8	379.3	1917.7
Adjustments to controllable opex	–20.1	–21.9	–21.1	–23.8	–25.9	–112.7
Adjustments to self insurance	–3.3	–3.3	–3.4	–3.5	–3.6	–17.2
Adjustment to debt raising costs	–0.1	–0.1	–0.3	–0.4	–0.6	–1.5
Adjustment to input cost escalators	–5.7	–8.4	–10.0	–10.6	–10.6	–45.4
Adjustment for overheads	7.8	14.4	13.8	12.3	12.1	60.4
Total AER approved opex allowance	351.3	368.4	368.2	362.7	350.6	1801.2

Note: Totals may not add due to rounding.

(a) This amount includes debt raising costs. This amount excludes proposed equity raising costs. The AER will allow Ergon Energy to amortise a total amount of $14.2 million ($2009–10) in benchmark equity raising costs for the next regulatory control period.

8.6 AER decision

In accordance with clause 6.12.1(4)(ii) of the NER, the AER does not accept Energex's proposed forecast opex for the next regulatory control period. The AER is not satisfied that Energex's forecast opex, taking into account the opex factors, reasonably reflects the opex criteria in clause 6.5.6 of the NER.

The AER's reasons are set out in section 8.4 of this decision.

The AER's estimate of Energex's required opex for the next regulatory control period, that reflects the opex criteria taking into account the opex factors, is set out at table 8.20 of this decision.

In accordance with clause 6.12.1(4)(ii) of the NER, the AER does not accept Ergon Energy's proposed forecast opex for the next regulatory control period. The AER is not satisfied that Ergon Energy's forecast opex, taking into account the opex factors, reasonably reflects the opex criteria in clause 6.5.6 of the NER.

The AER's reasons are set out in section 8.4 of this decision.

The AER's estimate of Ergon Energy's required opex for the next regulatory control period, that reflects the opex criteria taking into account the opex factors, is set out at table 8.21 of this decision.

9 Estimated corporate income tax

This chapter sets out the AER's consideration of issues raised in response to the draft decision on the estimation of corporate income tax for the Qld DNSPs. This includes the assumed value of imputation credits (gamma).

Under the imputation tax system operating in Australia, resident investors are able to offset their tax liabilities using imputation credits attached to dividend earnings. Any imputation credits in excess of an investor's tax liabilities can be claimed by the investor as a tax rebate. This means there is an inverse relationship between the assumed value of imputation credits and the tax building block allowance.

9.1 AER draft decision

The AER must make a decision on the estimated costs of corporate income tax to a DNSP in accordance with clause 6.5.3 of the NER. This clause provides the following formula for the calculation of the estimated cost of corporate income tax (ETC_t) of a DNSP for each regulatory year:

$$ETC_t = (ETI_t \times r_t)(1 - \gamma)$$

where:

ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the DNSP, operated the business of the DNSP, such estimate being determined in accordance with the post–tax revenue model;

r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and

γ is the assumed utilisation of imputation credits.

For these purposes:

(1) the cost of debt must be based on that of a benchmark efficient DNSP, and

(2) the estimate must take into account the estimated depreciation for that regulatory year for tax purposes, for a benchmark efficient DNSP, of assets where the value of those assets is included in the regulatory asset base for the relevant distribution system for that regulatory year.

The formula outlined in clause 6.5.3 of the NER incorporates a value for imputation credits (γ or gamma) in determining the appropriate company tax allowance. Under the Australian imputation tax system, domestic investors receive a credit for tax paid at the company level (an 'imputation credit') that offsets part or all of their personal income tax liabilities. For eligible shareholders, imputation credits represent a benefit from the investment in addition to any cash dividend or capital gains received.

The generally accepted regulatory approach in Australia has been to define the value of imputation credits as a product of the 'imputation credit payout ratio' (F) and the 'utilisation rate' (θ or theta).

The AER assessed each of the inputs to the post–tax revenue model (PTRM) that are used to calculate the expected cost of corporate income tax.

The AER considered that the Qld DNSPs' proposed tax remaining and tax standard asset lives were appropriate. The AER also considered the Qld DNSPs' proposed opening tax asset bases to be appropriate and reasonable. Using these inputs, the AER used the PTRM to calculate the allowance for corporate income tax, as set out in table 9.1.

Table 9.1: AER draft decision on corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	32.2	35.5	39.1	43.0	45.9	195.7
Ergon Energy	0.0	20.1	29.3	34.0	33.1	116.5

Note: Ergon Energy has no tax allowance for 2010–11 due to the carry forward of tax losses from previous years.

The AER considered the Qld DNSPs' regulatory proposals and the supporting information provided did not constitute persuasive evidence to justify a departure from a gamma of 0.65, as specified in the statement of regulatory intent (SORI).[760] In forming its view the AER considered the information provided by interested parties in response to the gamma determined in the SORI and considered it against its underlying criteria.[761]

9.2 Revised regulatory proposals

The Qld DNSPs did not accept the draft decision on gamma and proposed a gamma of 0.2, consistent with their original regulatory proposals. The Qld DNSPs submitted a report from Strategic Finance Group Consulting (SFG) to support their proposed gamma of 0.2.

9.2.1 Energex

Energex stated the SFG report provided further support for a gamma of 0.2. Energex submitted concerns have been raised with both the Beggs and Skeels (2006) and the Handley and Maheswaran (2008) studies, which were relied upon by the AER. In particular, Energex submitted the data used in the Handley and Maheswaran (2008) study has not been made available for review and therefore lacks transparency.[762]

760 AER, *Electricity transmission and distribution network service providers, Statement of revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009.

761 NER, clause 6.5.4(h)(1). The underlying criteria was set out in the draft decision, see AER, *Draft decision, South Australian draft distribution determination*, November 2009, p. 275.

762 Energex, *Revised regulatory proposal*, January 2010, pp. 38–39.

Energex submitted there is significant persuasive evidence, including previous evidence from the Joint Industry Associations and the SFG report, for the AER to depart from the 0.65 gamma set in the SORI. Energex stated that this evidence supports a gamma of 0.2.[763]

Energex proposed a total tax allowance of $528.9 million for the next regulatory control period.[764] This revised allowance reflects changes by Energex to various factors that affect revenues and costs.

Energex also revised its opening tax asset base as at 1 July 2010 and remaining tax asset lives at this date.[765] This was due to the revisions Energex made to capex for 2008–09 in its roll forward model (RFM) as discussed in chapter 5 of this decision.

9.2.2 Ergon Energy

Ergon Energy disagreed with the basis for the AER's gamma of 0.65 in the draft decision, including the AER's estimated range for theta and its assumed payout ratio for imputation credits. Ergon Energy submitted a report from SFG with its revised regulatory proposal to support its proposed gamma of 0.2.[766]

Ergon Energy has proposed a total tax allowance of $376.1 million for the next regulatory control period.[767] This revised allowance reflects changes to all factors that affect revenues and costs including the matters discussed below.

In its revised PTRM, Ergon Energy updated its estimated tax loss carried forward for 2009–10, revising this estimate down by $148 million compared to the draft decision. It also revised its opening tax asset base as at 1 July 2010 and remaining tax asset lives at this date.[768] This was due to the revisions Ergon Energy made to capex for 2008-09 and 2009–10 in its RFM, as discussed in chapter 5 of this decision.

9.3 Submissions

Energex made a submission in relation to gamma. Energex attached a report from Synergies on the estimation of gamma based on tax statistics with its submission.[769]

9.4 Consultants review

9.4.1 Gamma

The AER engaged consultants to provide expert advice on issues relating to the estimation of gamma raised by the Qld DNSPs.

Professor Michael McKenzie and Associate Professor Graham Partington from the University of Sydney provided advice on the estimation of gamma focussing on

763 Energex, *Revised regulatory proposal*, January 2010, p. 40.
764 Energex, *Revised regulatory proposal*, January 2010, Revised PTRM, confidential.
765 Energex, *Revised regulatory proposal*, January 2010, p. 41.
766 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 179–180.
767 Ergon Energy, *Revised regulatory proposal*, January 2010, Revised PTRM, confidential.
768 Ergon Energy, *Revised regulatory proposal*, January 2010, Revised PTRM, confidential.
769 Synergies, *Issues relating to cost of capital, response to the AER's draft decision*, February 2010.

dividend drop–off based estimates of theta. [770] McKenzie and Partington reviewed the SFG dividend drop-off study submitted by Energex and Ergon Energy in support of their proposed gamma of 0.2 and found significant data and methodological issues.[771] McKenzie and Partington also advised that relying on one type of study such as the SFG study would be inappropriate and that much more evidence can be adduced to support the AER's gamma value.[772]

Associate Professor John Handley from the University of Melbourne provided advice on issues relating to the estimation of gamma, focussing on conceptual matters, and the use of taxation statistics in estimating gamma.[773] Handley advised that the Synergies report submitted by Energex did not address the issue of double counting in Synergies' estimate of theta, which was identified in the draft decision.[774] Handley also advised that SFG's statements relating to the reliability of estimates of theta from tax statistics were incorrect.[775]

9.4.2 Tax asset base

In the draft decision, the AER (with the assistance of McGrathNicol Corporate Advisory (McGrathNicol)) assessed the Qld DNSPs' tax asset bases for RAB and non-RAB components for each year since the commencement of the National Tax Equivalents Regime (NTER). Based on this assessment the AER accepted that the tax asset bases proposed by the Qld DNSPs. The remaining tax asset lives and standard tax asset lives were also accepted as being consistent with the NER and the NTER.

The AER subsequently re–engaged McGrathNicol to identify any significant changes in the Qld DNSPs' revised regulatory proposals in the following aspects of their tax asset base:

- the starting point for calculating the initial tax asset base as at 1 July 2010
- the historic depreciation and tax depreciation assumptions (including the standard tax asset lives used by the DNSPs and the remaining tax asset lives calculated by the DNSPs as at 1 July 2010)
- the treatment of past additions and disposals
- the treatment of depreciation on capital contributions

770 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010.
771 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, pp. 4–5.
772 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, p. 4.
773 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010.
774 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 22–23.
775 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 17–22.

- the assumptions used to split assets between standard control, direct control, alternative control, negotiated and unregulated services
- the treatment of work-in-progress
- the size of any tax losses as at 1 July 2010 and the treatment of any such losses going forward.

9.5 Issues and AER considerations

9.5.1 Assumed utilisation of imputation credits (gamma)

9.5.1.1 The payout ratio for imputation credits

Synergies contended the payout ratio for imputation credits has been consistently below 100 per cent since the introduction of the imputation taxation scheme and a payout ratio of 70 per cent is reasonable.[776] The AER notes the WACC review assumed payout ratio of 100 per cent for imputation credits based on a number of considerations, including:[777]

- a 100 per cent payout ratio is consistent with the Officer WACC framework that assumes cash flows to perpetuity
- it is consistent with the PTRM, which assumes cash flows to perpetuity and that cash flows are fully distributed at the end of each period
- there are significant difficulties in estimating the time value loss associated with retained imputation credits, but it is likely that retained imputation credits do have value
- based on an observed payout ratio from tax statistics of 71 per cent and the assumption that retained imputation credits do have value, the actual payout ratio in practice is unlikely to be significantly less than 100 per cent.

Synergies estimate of the payout ratio from tax statistics

Synergies stated the draft decision incorrectly concluded that estimating the imputation credit payout ratio from tax statistics results in double counting credits created. Synergies stated that imputation credits generated in one company and then transferred to an interposed entity will be counted as being created twice. However, the imputation credits are also recorded as being distributed twice when estimating the payout ratio using tax statistics, which means that in any one year the two effects countervail each other.[778]

Handley noted that the issue of double counting affects Synergies' estimation of theta using tax statistics. However, Handley also noted that in estimating the payout ratio using tax statistics, the effect of double counting credits created is largely cancelled

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776 Synergies, *Issues relating to cost of capital, response to the AER's draft decision*, February 2010, pp. 6–8.

777 AER, *Final decision, WACC parameters*, May 2009, p. 420.

778 Synergies, *Issues relating to cost of capital*, February 2010, pp. 7–8.

out by double counting of credits distributed.[779] The AER agrees with Handley and notes that this was a misinterpretation by the AER in the draft decision. The AER considers that the issue of double counting severely affects Synergies' estimate of theta using tax statistics, [780] but does not severely affect Synergies' estimate of the payout ratio using tax statistics. The issue of double counting in Synergies' estimate of theta is discussed below in the context of estimates of theta from tax statistics.

The payout ratio incorporating the value of retained imputation credits

SFG stated if a payout ratio of 71 per cent is assumed, it is impossible for retained credits to be routinely distributed between one and five years after they are created.[781] Synergies submitted that the past 20 years of corporate data shows that the payout ratio has consistently been below 100 per cent and that 70 per cent is a reasonable estimate of the payout ratio.[782]

In both the draft decision and the WACC review, the AER considered the payout ratio in any one year is approximately 71 per cent, as estimated by Hathaway and Officer (2004). However, the AER also considered that retained imputation credits that are not paid out immediately are likely to have value to investors, which should be incorporated in estimating the payout ratio.[783] The AER notes McKenzie and Partington's advice that empirical evidence from Hubbard and Kemsley (2001), and Ricketts and Wilkinson (2008) supported the view that retained imputation credits have positive value.[784]

The AER also notes Handley's advice that the general consensus is the observed payout ratio in any one year is approximately 70 per cent, but that the issue of contention is the likely value of retained imputation credits. Handley noted the likely value of retained imputation credits cannot be reliably estimated without significant further research. In particular, Handley noted that, in recognising the value of undistributed imputation credits, a further three parameters would need to be estimated to obtain a gamma estimate (in addition to theta)—the payout ratio (and

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779 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 23. Double counting occurs when aggregated company statistics are used. In estimating of theta using tax statistics, Synergies used aggregated company tax statistics to estimate credits created, but not credits distributed–thus theta was underestimated. However in estimating the payout ratio using tax statistics, Synergies used aggregate company tax statistics to estimate credits created as well as credits distributed. Therefore the issue of double counting was not as severe when estimating the payout ratio. See footnote 4 of the Handley report.

780 The AER notes Synergies estimate of theta uses credits actually used (which does not incorporate double counting) and divides this by the dollar value of dividends paid taken from aggregate company statistics (which does incorporate an unknown amount of double counting). Consequently, Synergies' estimate of theta is downwards biased by an unknown amount.

781 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, p. 17.

782 Synergies, *Issues relating to cost of capital*, February 2010, pp. 6–8.

783 AER, AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 204–205 and AER, *Final decision, WACC parameters*, 1 May 2009, pp. 415–420.

784 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, pp. 25–26.

implicitly the percentage of imputation credits retained), the appropriate discount rate for retained imputation credits, and the expected retention period.[785]

As noted in the WACC review, the AER is not aware of any independent and reliable empirical research that specifically explores the likely value of retained imputation credits. However, the AER considers an assumption that retained imputation credits are worthless is inappropriate. The AER notes that this view is consistent with the advice of its consultants.[786] In the WACC review the AER demonstrated that under a reasonable set of assumptions the payout ratio including any time value loss associated with retained imputation credits was not significantly less than 100 per cent.[787] That said, the AER acknowledges that a retention period of five years may be more appropriate (for example a retention period consistent with the term of the risk–free rate). However, as already discussed, the AER is unaware of any independent and reliable research on this matter.

The AER's basis for assuming a 100 per cent payout ratio

SFG stated the Officer (1994) paper which sets out the Officer WACC framework also includes a worked example that assumes a distribution rate of 76 per cent.[788] Handley noted the Officer WACC framework clearly assumes that cash flows continue into perpetuity, which is equivalent to assuming a 100 per cent payout ratio.[789] Handley also noted the worked example in the Officer (1994) paper is internally inconsistent with the Officer WACC framework.[790] The AER agrees with Handley and considers that the assumption of a 100 per cent payout ratio is consistent with the Officer WACC framework, which clearly assumes cash flows to perpetuity.

As noted above, the AER considers the actual payout ratio, incorporating the value of retained imputation credits is between 70 per cent and 100 per cent, which is consistent with the advice of its consultants.[791] However, in the WACC review, the AER did not rely on this alone to conclude that a payout ratio of 100 per cent was appropriate.

The AER notes that the estimate of corporate income tax (incorporating a value for gamma) forms part of the PTRM framework, which employs a benchmark regulatory

785 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 35–38.
786 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, pp. 25–26; and Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 35–38.
787 AER, *Final decision, WACC Parameters*, 1 May 2009, p. 418.
788 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 15–16.
789 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 40.
790 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 40.
791 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, p. 27 and Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 38.

framework. Consistent with the WACC review, the AER considers the assumption of a 100 per cent payout ratio is appropriate because:[792]

- it is consistent with the PTRM, which assumes cash flows to perpetuity and thus the full distribution of cash flows at the end of each period

- it is consistent with the Officer WACC framework, which clearly assumes cash flows to perpetuity.

In the WACC review the AER also noted that the assumption of a 100 per cent payout ratio simplifies the framework for estimating gamma.[793] The AER considers this remains appropriate due to the difficulty in reliably estimating the value retained imputation credits.

Based on the factors discussed above, the AER considers it remains appropriate to assume a 100 per cent payout ratio consistent with the draft decision and the WACC review.

9.5.1.2 Market practice

SFG submitted the market practice is to not incorporate a value for gamma when conducting valuation exercises. In particular SFG stated that the value of gamma does not affect the equilibrium cost of capital, which SFG submitted is the forward looking rate of return commensurate with prevailing conditions in the market for funds.[794]

The AER notes clause 6.5.3 of the NER requires a value for gamma to be incorporated in estimating the cost of corporate income tax (the tax building block). Clause 6.5.2 of the NER requires that the rate of return for a distribution network service provider to be calculated as a nominal post-tax WACC. Having regard to clause 6.5.2 and 6.5.3 of the NER, the AER uses the cost of corporate income tax (and implicitly the estimated value of gamma) to convert the rate of return into a post-tax rate of return. This involves estimating a post-tax cost of equity and a post-tax cost of debt. The AER utilises the Officer WACC framework to convert the conventional cost of equity into an after company tax cost of equity.

SFG submitted imputation credits are likely to have value to investors. However, SFG contended the equilibrium cost of capital in Australia does not incorporate a value for gamma since it is not used in valuation exercises, which is why gamma should be set to zero in estimating the rate of return.[795]

The AER does not consider it appropriate to assume that imputation credits are worthless, either explicitly or implicitly, by setting gamma to zero when estimating the post-tax rate of rate of return.

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792 AER, *Final decision, WACC parameters*, 1 May 2009, p. 420.
793 AER, *Final decision, WACC parameters*, 1 May 2009, p. 420.
794 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 7–9.
795 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 9–10.

The AER notes the advice of McKenzie and Partington, which stated that the Truong, Partington and Peat (2008) study illustrated the majority firms that do not account for imputation credits do so because it is too difficult to incorporate a value for gamma. The Truong, Partington and Peat (2008) study finds only 6 out of 89 firms surveyed cited the reason for not incorporating a value for gamma is because they considered that imputation credits have zero market value.[796]

Based on the considerations above, particularly the fact that imputation credits are likely to have value to investors, the AER considers it inappropriate to set gamma to zero when estimating the post–tax rate of return for the Qld DNSPs.

9.5.1.3 Estimating theta from tax statistics

Use of tax statistics to estimate theta

SFG submitted it is inappropriate to estimate theta from tax statistics because the AER relied on the following three propositions, which SFG claimed are either false or have no basis:[797]

1. gamma does not affect the cost of capital
2. the forcible removal of foreign investment would (in reality) not affect the cost of capital of Australian firms
3. the forcible removal of foreign investment would increase the estimate of theta under all methodologies.

In relation to SFG's first proposition, the AER notes that SFG appears to have misinterpreted the AER's conclusion based on Handley's advice in the WACC review. SFG submitted that the AER's conclusion in the WACC review was that an increase in gamma will not decrease the cost of equity to the firm.[798] However, the AER actually concluded that for any assumed value of gamma the total return to the shareholder will remain the same and thus the value of the firm will remain the same.[799]

For clarity, the AER notes in the WACC review, it concluded that for any *one* given value of gamma, the valuation of a company will remain the same. The AER did not conclude that changes in gamma will not affect the value of the firm, rather the inclusion of gamma does not affect the cost of capital for the firm as long as it is consistently reflected in cash flows and the discount rate. This is noted in Handley's March 2010 advice to the AER.[800]

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796 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, pp. 27–28.

797 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 31–35.

798 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, p. 31.

799 AER, *Final decision, WACC parameters*, 1 May 2009, p. 455.

800 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 17–18.

In relation to SFG's second proposition, it stated that if simple average redemption rates are used the removal of foreign investors would increase gamma and reduce the cost of equity to the firm. SFG submitted that this is unreasonable.[801]

The AER notes Handley's advice that SFG incorrectly analysed the conventional cost of equity, without incorporating any change to the grossed up cost of equity, to make the conclusion that the removal of foreign investors would reduce the cost of equity.[802] Handley demonstrated that if the change to the grossed up cost of equity is correctly incorporated, an increase in gamma would also increase both the grossed up cost of equity and the conventional cost of equity. [803] The AER notes this is because the conventional cost of equity is expressed by Officer (1994) as a modification of the grossed up cost of equity. This is illustrated by the following equations:

$$\text{Grossed up cost of equity} = r_e \tag{1}$$

$$\text{Conventional cost of equity} = r_e \frac{1-T}{1-T(1-\gamma)} \tag{2}$$

The AER notes that equation 1 represents the 'after-company-before-personal tax' cost of equity. This is because theoretically, under an imputation tax system, the payment of franked dividends will remove the effect of taxation on company profits that are eventually paid out as dividends. Thus the investor will not be double taxed on their dividend returns—the imputation credits paid can be collected from the tax office either as an offset or a tax refund. Equation 2 represents the 'after-company-after-some-personal tax' cost of equity. This is because company profits have already been taxed before being paid out as dividends. Without incorporating a value for gamma, this reflects a cost of equity where some company tax has already been collected by the tax office out of shareholders dividends.

Handley's advice noted that SFG analysed the conventional cost of equity (equation 2), and then assumed gamma would increase if foreign investors were removed. However, SFG did not assume an increase in the grossed up cost of equity, which it should have.[804]

Based on Handley's advice, the AER considers SFG's proposition that the removal of foreign shareholders would decrease the cost of equity if taxation redemption rates are used is incorrect.

In relation to SFG's third proposition, it stated the AER assumes that the estimate of theta would increase if foreign investors were removed and that this is true under all

801 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 33–34.

802 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 19–21.

803 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 21.

804 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 19–22.

methodologies. SFG stated this is inappropriate because, unlike redemption rates, techniques that use observed market prices to estimate theta do not automatically incorporate an increase in gamma from a reduction in foreign investors.[805]

The AER considers the assumption that theta would increase following a reduction in foreign investors is a reasonable assumption with a strong basis. As noted in the WACC review, domestic investors are likely to value imputation credits more highly than foreign investors.[806] This is readily reflected in estimates of theta from tax statistics and theory would suggest that this is also likely to be true under market based estimates of theta, such as dividend drop–off studies. However, the AER notes that dividend drop–off based estimates of theta are highly variable and are subject to multicollinearity and noise issues as discussed below. This is consistent with the advice provided by McKenzie and Partington.[807]

SFG submitted that market based estimates of theta provide observable results, which avoid the need for assumptions and thus market based estimates of theta should be preferred to estimates based on tax statistics.[808]

The AER notes McKenzie and Partington's advice, which stated that dividend drop–off based estimates of theta do not rely on observability alone but are in fact dependent on the assumptions of the model chosen.[809] Based on this advice and the concerns outlined below in relation to market based estimates of theta, the AER considers it appropriate to rely on both tax statistics studies and dividend drop–off studies in estimating theta.

Synergies submission on the use of tax statistics to estimate theta

In the draft decision, the AER noted Handley's advice that Synergies' estimate of theta from tax statistics was understated by an unknown amount due to a serious methodological flaw.[810] Handley's March 2010 advice re-iterated his earlier advice that Synergies' estimate of theta takes the value of credits actually used from the Australian Tax Office (ATO) tax statistics and divides this by the dollar value of imputation credits paid from aggregated company tax statistics.[811] The AER considers this to be a problem because credits actually used is not double counted in the ATO tax statistics, but the dollar value of dividends paid taken from aggregate company

805 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 34–35.

806 The AER notes that imputation credits are likely to have some value to non-resident investors, but it is likely to be less than the value of imputation credits to domestic investors. Non-resident investors can sell shares to domestic investors who are able readily utilise imputation credits and there may be other tax agreements with foreign countries that may enable the utilisation of imputation credits by non-resident investors.

807 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010.

808 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, p. 35.

809 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, p. 14.

810 AER, *Draft decision*, *Queensland distribution determination* November 2009, pp. 208–209.

811 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 21.

statistics does incorporate an unknown amount of double counting. Consequently, Synergies' estimate of theta is downwards biased by an unknown amount.

Synergies submitted, in the context of the payout ratio, the issue of double counting is largely cancelled out and therefore its estimate of theta is also not subject to double counting.[812] The AER notes, as discussed above, that double counting does not severely affect Synergies estimate of the payout ratio because in estimating the payout ratio aggregate company statistics are used in both the numerator and the denominator. This means double counting is largely cancelled out over time when estimating the payout ratio. However, the issue of double counting does affect Synergies' estimate of theta from tax statistics and this has not been addressed by Synergies. As a result, the AER considers that Synergies' estimate of theta from tax statistics cannot be relied upon.

Synergies also submitted that market based estimates should be used rather than tax statistics based estimates because the Monkhouse approach defines theta as the value of distributed imputation credits to investors, as a proportion of their face value.[813]

The AER notes McKenzie and Partington's advice that market based estimates of theta in the form of dividend drop–off studies are subject to significant concerns due to noise in the data and the likely effects of multicollinearity on the regression results. McKenzie and Partington advised that given the drawbacks of both dividend drop–off based estimates and taxation statistics based estimates, it is best to consider the evidence across all sources rather than one type of study alone.[814]

Based on the advice of McKenzie and Partington, and consistent with the draft decision, the AER considers it appropriate to use a tax statistics based estimate of theta in addition to a market based estimate.

9.5.1.4 Estimating theta from market prices

In the WACC review, the AER concluded that the Beggs and Skeels (2006) estimate of theta was the most reliable market based estimate of theta currently available.[815] SFG submitted that its dividend drop–off based estimate of theta of 0.23 uses an updated data set. SFG submitted that this estimate is supported by Associate Professor Skeels.[816]

The AER considers that SFG's estimate of theta is unreliable for the following reasons:

- Within the same sub–sample period of 1 July 2000 to 1 May 2004, the SFG study produces significantly different results to the Beggs and Skeels (2006) study. For

812 Synergies, *Issues relating to cost of capital, response to the AER's draft decision*, February 2010, pp. 9–12.
813 Synergies, *Issues relating to cost of capital, response to the AER's draft decision*, February 2010, pp. 9–12.
814 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, pp. 3–5.
815 AER, *Final decision, WACC parameters*, 1 May 2009, pp. 447–448.
816 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 28–29.

this reason the AER considers that the SFG study's methodology is likely to materially differ from Beggs and Skeels' (2006) methodology.[817]

- McKenzie and Partington noted that SFG's estimates are likely to be affected by multicollinearity as well as other data and methodological issues, which suggests that SFG's theta estimate of 0.23 is unreliable.[818]

SFG also submitted that dividend drop–off estimates of theta are conditional on the particular value of cash dividends that is adopted.[819] The AER notes McKenzie and Partington's advice, which stated that placing restrictions on parameters may bias the least squares estimate unless the restrictions are true.[820] To this end the AER does not consider it appropriate to set the value of a dollar of cash dividends to 100 cents in the context of estimating theta using dividend drop–off studies.

As noted in the WACC review, the AER considers dividend drop–off based estimates of theta are subject to considerable imprecision due to issues such as multicollinearity.[821] For this reason, the AER considers that the independent statistical significance of the estimate of theta and the estimate for the value of cash dividends is necessary for reliable results. Therefore, the AER considers it inappropriate to ascribe a particular value to cash dividends.

The AER notes dividend drop–off studies such as Beggs and Skeels (2006) attempt to separately estimate the value of cash dividends and the value imputation credits. This ensures that the estimate of theta is not biased by an ascribed value for cash dividends.

9.5.1.5 Time period for estimating theta

In the WACC review, the AER used the post–July 2000 estimates of theta from Beggs and Skeels (2006) to determine a reliable point estimate of theta from market prices. The AER used post–July 2000 estimates due to the tax regime change in 2000, which allowed the full rebate of imputation credits to resident tax payers.[822]

SFG submitted that the Beggs and Skeels (2006) estimates for the year 2000 were unreliable. SFG submitted the AER inappropriately concluded that a structural break occurred following the 2000 tax regime change based on these unreliable estimates.[823]

The AER notes that there are strong conceptual grounds for assuming a structural break following the 2000 tax regime change because this change allowed the full rebate of imputation credits in excess of tax liabilities, which was not previously

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817 This is discussed in AER, *Draft decision, South Australian draft distribution determination*, 25 November 2009, pp. 268–269.

818 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, pp. 23, 44–50.

819 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 28–29.

820 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, p. 46.

821 AER, *Final decision, WACC parameters*, 1 May 2009, p. 437.

822 AER, *Final decision, WACC parameters*, 1 May 2009, pp. 426–430.

823 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 24–25.

allowed. This was also noted in the WACC review and is supported by conclusions of Beggs and Skeels (2006).[824]

In the WACC review, the AER noted the Beggs and Skeels (2006) conclusion that the 2000 tax regime change had a permanent impact on the value of imputation credits based on results from the 1998–2000 interval and 2001–2004 interval.[825] Beggs and Skeels (2006) did not rely on results from the year 2000 alone to reach this conclusion. The AER also notes McKenzie and Partington's advice, which stated that in theory a clear case cannot be made for estimating across tax regimes.[826]

SFG submitted Handley and Maheswaran (2008) assumed that resident investors could redeem 100 per cent of imputation credits distributed following the 2000 tax regime change.[827] The AER notes that this issue was considered in detail in the explanatory statement on the WACC review.[828]

In the WACC review explanatory statement, the AER noted that there are strong conceptual grounds to assume a structural break following the 2000 tax regime change and that this was appropriately incorporated in the Handley and Maheswaran (2008) tax statistics study. However, given that there was a methodological change for the post–2000 period, the AER took a cautious view and determined a point estimate for theta of 0.74. This estimate was calculated as the mid-point of the pre–2000 estimate of 0.67 and the post–2000 estimate of 0.81 from the Handley and Maheswaran (2008) study.[829] The 0.74 point estimate of theta from the Handley and Maheswaran (2008) study was used in the AER's WACC review final decision.[830]

SFG submitted that, in the absence of a structural break, a longer sample of data (including pre–2000 data) should be used to estimate theta. As discussed above, the AER considers that there is evidence of a structural break following the 2000 tax regime change, which is supported by the empirical data and conclusions of Beggs and Skeels (2006), as well as the advice of McKenzie and Partington.

The AER concludes that estimates of theta for the post–July 2000 period are the most appropriate estimates to determine a forward looking estimate of theta. The AER considers this is appropriately incorporated in its point estimates of theta from the Handley and Maheswaran (2008) tax statistics study and the Beggs and Skeels (2006) dividend drop–off study.

9.5.1.6 Consistency issues related to the AER's estimate of theta

SFG submitted that the value of a dollar of cash dividend should be set to 100 cents when estimating the value of imputation credits using dividend drop–off studies because this maintains consistency with the AER's use of the capital asset pricing

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824 AER, *Final decision, WACC parameters*, 1 May 2009, pp. 426–430.
825 AER, *Final decision, WACC parameters*, 1 May 2009, p. 429.
826 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, p. 42.
827 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, p. 24.
828 AER, *Explanatory statement, WACC parameters*, December 2008, pp. 310–318, 333.
829 AER, *Explanatory statement, WACC parameters*, December 2008, pp. 332–333.
830 AER, *Final decision, WACC parameters*, 1 May 2009, pp. 466–467.

model (CAPM).[831] SFG submitted that dividend yield studies[832] estimate a dollar of cash dividends to be valued at 100 cents and that the 'relevant and important' dividend drop–off studies estimate the value of a dollar of cash dividends to be 100 cents.[833]

The AER notes that it has not used a dividend *yield* study to estimate a value for theta. The AER relied on the Beggs and Skeels (2006) dividend *drop–off* study to determine a reliable estimate of theta from market prices.[834] SFG referred to Boyd and Jagganathan (1994) and Graham, Michaely and Roberts (2003) as 'relevant and important' dividend drop–off studies that estimate the value of a dollar of cash dividend to be 100 cents.

The AER notes Handley's advice that, contrary to SFG's view, the majority of empirical evidence from dividend drop–off studies supports a value for a dollar of cash dividend of less than 100 cents.[835] Handley further noted that:[836]

- the Boyd and Jagganathan (1994) paper relies substantially on arbitrage arguments (in addition to equilibrium considerations) and therefore the results of the paper should be interpreted with caution

- only a small subset (5 per cent) of stocks analysed by Graham, Michaely and Roberts (2003) provide an estimate where a dollar of cash dividends is valued at 100 cents. When the full sample of stocks is used, a dollar of cash dividend is valued at less than 100 cents.

Taking account of Handley's advice the AER considers that the majority of empirical evidence from dividend drop–off studies supports a value for a dollar of cash dividends less than 100 cents, which is consistent with the Beggs and Skeels (2006) estimates.

SFG submitted that it would be possible to maintain consistency with the CAPM by constraining the value of a dollar of cash dividends to be 100 cents when estimating the value of theta using dividend drop–off studies. SFG also constructed a joint confidence interval for sets of estimates for the value of cash dividends and imputation credits based on the data it used in its dividend drop–off study. SFG

[831] SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, p. 37.
[832] Dividend yield studies were relied upon in the WACC review to justify the use of the CAPM.
[833] SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, p. 43.
[834] The AER agrees with Handley's March 2010 advice, which noted general agreement that dividend yield studies generally estimate the value of a dollar of cash dividends to be valued at 100 cents. See Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 26. However, the AER has used a dividend drop–off study and the majority of dividend drop–off studies estimate a dollar of cash dividends to be worth less than 100 cents. As discussed below, it is inappropriate to ascribe a value for cash dividends in a dividend drop–off study, because it will necessarily bias the estimate of theta due to the presence of multicollinearity.
[835] Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, p. 27.
[836] Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 26–28.

submitted that estimates where a dollar of cash dividends is constrained to being valued at 100 cents falls within its joint confidence interval.[837]

As noted above, the AER considers dividend drop–off based estimates of theta are subject to considerable imprecision due to issues such as multicollinearity. For this reason, the AER considers that the independent statistical significance of the estimate of theta and the estimate for the value of cash dividends is necessary for reliable results in the context of a dividend drop–off study.

The AER considers it inappropriate to ascribe a value for cash dividends when estimating theta using dividend drop–off studies, because it is likely to bias the estimate of theta. This is consistent with the advice McKenzie and Partington.[838]

The AER also notes that the joint confidence interval constructed by SFG simply illustrates the high variability of estimates possible based on SFG's data. This was noted in Handley's advice, which stated that an estimate for theta of 0.78 would also fall within SFG's joint confidence interval.[839] McKenzie and Partington also noted that what SFG's joint confidence interval does, is to illustrate the likely impact of multicollinearity on dividend drop–off based estimates of theta.[840]

The AER concludes that the estimates of theta and the value of a dollar of cash dividends should be estimated independently in the context of a dividend drop–off study. Constraining the value of a dollar of cash dividend to 100 cents is likely to bias the estimate of theta in a dividend drop–off study. The AER concludes that the Beggs and Skeels (2006) estimates are reasonable as the majority of dividend drop–off studies estimate the value of a dollar of cash dividends to be less than 100 cents.

9.5.1.7 Conclusion

The AER has considered the information provided by Energex and Ergon Energy on gamma as part of their revised regulatory proposals and Energex's submission to the AER, including consultants' reports. The issues raised relate to both the assumed payout ratio for imputation credits and the assumed utilisation of imputation credits, theta.

For the reasons outlined above, the AER confirms its draft decision on the value of gamma. The AER considers that the most appropriate value for the payout ratio is 100 per cent. This value provides simplicity because it does not require estimation of the exact value of retained imputation credits. A 100 per cent payout ratio is consistent with the Officer WACC framework and is also consistent with the cash flow perpetuity assumptions made within the PTRM.

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837 SFG, *Gamma: further evidence to support departure from the AER's statement of regulatory intent*, 7 December 2009, pp. 41–43.

838 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, p. 44.

839 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010, pp. 30–31.

840 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010, pp. 45–47.

The AER considers that the most reasonable and reliable estimate of theta currently available is 0.65. Based on the advice of its consultants, the AER does not consider that SFG's estimate of theta can be relied upon due to data and methodological issues. The AER considers that the best estimate of theta from market based studies is 0.57 as estimated in the Beggs and Skeels (2006) dividend drop–off study for the post–July 2000 period. However, due to the high variability of dividend drop-off based estimates of theta, the AER has also relied on the 0.74 point estimate of theta from the Handley and Maheswaran (2008) tax statistics study.

The AER notes that Energex requested the underlying data from the Handley and Maheswaran (2008) tax statistics study.[841] Ideally the AER would prefer that the underlying data be made public. However, due to the proprietary nature of the data used by Handley and Maheswaran, the AER has been unable to obtain the underlying data. The AER also notes that it has been unable to obtain the underlying data from the Beggs and Skeels (2006) dividend drop–off study for similar reasons.

Notwithstanding this, the AER notes that both the Handley and Maheswaran (2008) study and the Beggs and Skeels (2006) study are independent, published studies, which have been academically peer reviewed. The AER considers that the process of review before an academic journal article can be published is robust and therefore the study can be reasonably relied upon.

Overall, the AER does not consider that the information provided by Energex and Ergon Energy in support of their revised regulatory proposals constitutes persuasive evidence justifying a departure from the gamma of 0.65 set in the SORI and applied in the draft decision. In forming its view the AER has considered the information provided by interested parties in response to the gamma determined in the SORI and applied in the draft decision, and assessed it against the underlying criteria.

9.5.2 Tax asset bases

Under clause 6.5.3(2) of the NER, the estimate for the cost of corporate income tax must take into account the estimated tax depreciation of assets for a benchmark efficient DNSP, where the value of those assets is included in the RAB. Achieving this outcome requires:

- the tax asset values of the RAB assets to be consistent with those used for tax purposes
- the tax standard lives and tax remaining lives of the RAB assets to be consistent with those used for tax purposes.

Common issues

Notwithstanding Energex's treatment of equity raising costs as discussed below, the AER notes that neither of the Qld DNSPs altered their standard tax asset lives from those approved in the draft decision. Accordingly, the AER confirms its position in

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841 Energex, *Revised regulatory proposal*, January 2010, p. 39 and Energex, *Letter on gamma factor*, 6 April 2010, confidential.

the draft decision that these standard tax asset lives are consistent with the requirements of the NER.

Energex did not provide a standard tax asset life for equity raising costs in its revised PTRM or an explanation for not doing so. In the draft decision, the AER applied the same standard asset life associated with equity raising costs for regulatory depreciation (or amortisation) and tax depreciation purposes. However, after further investigation of this matter, the AER identified an ATO determination that requires equity raising costs to have a standard tax asset life of 5 years.[842] The AER therefore uses a standard tax asset life for equity raising costs of 5 years in the Qld DNSPs' PTRMs. The AER's decision on the Qld DNSPs' standard asset lives associated with equity raising costs for regulatory depreciation purposes is discussed in chapter 10 of this decision.

Energex

McGrathNicol noted that Energex had provided revised actual capex for 2008–09.[843] The revised capex figure for 2008–09 is discussed in chapter 5 of this decision. The AER has accepted these changes and the resulting impact on Energex's tax asset base. For similar reasons, the AER has also accepted the impact of the revised forecast for metering capex in 2009–10 on Energex's tax asset base.

McGrathNicol did not identify any further significant changes in Energex's revised regulatory proposal regarding the tax asset base (including the remaining tax asset lives).[844] The AER therefore confirms its draft decision in relation to the tax asset base issues assessed by McGrathNicol.

Ergon Energy

McGrathNicol noted that Ergon Energy had provided revised capex for 2008–09 based on actuals and revised forecast capex for 2009–10.[845] The AER accepts both these changes made by Ergon Energy to its revised regulatory proposal and the resulting impact on its tax asset base. The revisions to the capex figures for 2008–09 and 2009-10 were discussed in chapter 5 of this decision.

Due to insufficient information, McGrathNicol could not form a firm opinion on the appropriateness of Ergon Energy's calculation of the tax loss carried forward and suggested the AER investigate this matter further.[846] In response to several questions from the AER, Ergon Energy provided information that highlighted that revised capital contribution and opex figures for 2008–09 and 2009–10 had resulted in the

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842 ATO, *Guide to depreciating assets 2001–02: Business» related costs - section 40-880 deductions, ATO reference; NO NAT7170.*

843 McGrathNicol, *Assessment of the revised proposal of Energex's tax asset base*, 29 March 2010, p. 4.

844 McGrathNicol, *Assessment of the revised proposal of Energex's tax asset base*, 29 March 2010, pp. 4–5.

845 McGrathNicol, *Assessment of the revised proposal of Ergon Energy's tax asset base*, 29 March 2010, p. 4.

846 McGrathNicol, *Assessment of the revised proposal of Ergon Energy's tax asset base*, 29 March 2010, p. 5.

change in the tax loss carried forward amount.[847] Based on this information, the AER is satisfied that the information provided by Ergon Energy adequately explains the tax loss carried forward in the revised regulatory proposal.[848]

McGrathNicol did not identify any other significant changes in Ergon Energy's revised regulatory proposal regarding the tax asset base, although it did reiterate certain findings in its report for the draft decision, including the issue of the tax loss carried forward.[849] Besides the tax loss carried forward, these matters were previously considered by the AER, which is satisfied that these matters have been appropriate dealt with or are otherwise immaterial.

As discussed in chapter 5 of this decision, the AER required Ergon Energy to provide forecast disposals for 2009–10. These forecasts reduce the tax asset base and remaining tax lives as proposed by Ergon Energy in its revised regulatory proposal. These changes are reflected in the AER's revisions to Ergon Energy's PTRM.

9.6 AER conclusion

The AER does not consider that there is persuasive evidence justifying a departure from the gamma of 0.65 set in the SORI and applied in the draft decision. The AER does not consider that Energex or Ergon Energy have demonstrated that, in light of the underlying criteria, a material change in circumstances since the date of the SORI, or any other relevant factor makes the gamma value of 0.65 set in the SORI and applied in the draft decision inappropriate.

The AER considers that the gamma value of 0.65 adopted in the WACC review and subsequently in the draft decision is the best estimate of gamma based on the most reliable evidence available. The market based estimates of theta in the form of dividend drop–off studies are subject to significant concerns due to noise in the data and the likely effects of multicollinearity on the regression results. Therefore, the AER considers that a theta estimate of 0.65, based on an estimate from tax statistics as well as an estimate from market prices, is better than a market based estimate alone.

The AER considers that, subject to the adjustments noted above, the tax inputs into the Qld DNSPs' PTRM and RFM are consistent with the tax provisions of the NER.

The allowances for corporate income tax determined by the AER are presented in table 9.2. These figures are calculated using the PTRM and based on the tax inputs discussed above.

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[847] Ergon Energy, email to the AER, *AER.ERG.RRP.14*, 15 February 2010, Ergon Energy, email to the AER, *AER.ERG.RRP.35*, 22 March 2010 and Ergon Energy, email to the AER, *AER.ERG.RRP.38*, 22 March 2010.

[848] The AER notes that the opex figures reported in the regulatory information notice are based on the AER approved cost allocation methodology (CAM). However, the opex figures used in the calculation of the tax loss carried forward are based on the QCA's CAM, which is appropriate given that Ergon Energy was regulated by the QCA during the period in question.

[849] McGrathNicol, *Assessment of the revised proposal of Ergon Energy's tax asset base*, 29 March 2010, p. 6.

Table 9.2: AER conclusion on corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	32.5	35.1	38.5	42.5	45.6	194.3
Ergon Energy	9.6	27.4	29.6	34.4	33.4	134.4

Note: Totals may not add due to rounding.

9.7 AER decision

In accordance with clause 6.12.1(7) of the NER the estimated cost of corporate tax to Energex for each regulatory year of the next regulatory control period is as specified in table 9.2 of this decision.

In accordance with clause 6.12.1(7) of the NER the estimated cost of corporate tax to Ergon Energy for each regulatory year of the next regulatory control period is as specified in table 9.2 of this decision.

10 Depreciation

This chapter sets out the annual allowances for regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB). It also sets out the AER's assessment of the Qld DNSPs' proposed asset lives used to calculate their depreciation schedules for the next regulatory control period.

Regulatory depreciation is used to model the nominal asset values over the regulatory control period and provides the depreciation allowance in the annual revenue requirement. The annual regulatory depreciation allowance is an amortised value of the RAB, derived using a specified depreciation schedule that reflects the nature of the assets over their economic life. Regulatory practice has been to assign a regulatory life (standard or remaining life) to each category of assets that equals its expected economic life.

10.1 AER draft decision

The AER assessed the remaining asset lives and standard asset lives used by the Qld DNSPs as inputs to their post tax revenue models (PTRM), and the resulting regulatory depreciation allowances.

The AER accepted Energex's proposed remaining asset lives. The AER did not accept the remaining asset lives proposed by Ergon Energy due to an error which had a significant impact on Ergon Energy's depreciation allowance. The AER accepted the standard asset lives proposed by the Qld DNSPs.[850]

The AER also accepted Ergon Energy's claim for accelerated depreciation in relation to assets destroyed by Cyclone Larry, although the amount to be recovered was revised to reflect the timing of when these assets were written off in Ergon Energy's accounts.[851]

On the basis of the AER's approved asset lives, opening RAB, and forecast capex allowance, the AER determined the Qld DNSPs' regulatory depreciation allowances for the next regulatory control period, as set out in table 10.1.

Table 10.1: AER conclusion on regulatory depreciation allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex	87.1	97.2	108.9	120.6	121.7	535.6
Ergon Energy	151.0	158.3	157.9	171.4	152.2	790.8

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 227.
Note: These depreciation allowances included equity raising costs that were amortised.
The depreciation allowance for Ergon Energy did not include its accelerated depreciation claim for destroyed assets. These assets were accounted for separately in the PTRM.

850 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 221–222.
851 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 224–225.

No submissions were received regarding the depreciation allowances of the Qld DNSPs.

10.2 Revised regulatory proposals

10.2.1 Energex

Energex proposed a total regulatory depreciation allowance of $513 million for the next regulatory control period, reflecting revisions to its RAB and assets lives.

Energex stated that its revision to the opening RAB as at 1 July 2010 to account for actual capital expenditure in 2008–09 impacts on the calculation of remaining asset lives to apply for the next regulatory control period. Energex stated that its revised remaining asset lives were based on the same methodology reviewed and accepted by the AER in its draft decision.[852]

Energex accepted the draft decision to include equity raising costs in the RAB and amortise these costs over a standard asset life, based on a weighted average life of all assets in the RAB at 1 July 2010.[853] Energex stated that following the update of the capex for 2008–09 in the RAB, it had recalculated the standard asset life of the equity raising costs to be 46.1 years.

10.2.2 Ergon Energy

Ergon Energy proposed a total regulatory depreciation allowance of $782 million for the next regulatory control period, reflecting revisions to its RAB and revised assets lives.

Ergon Energy noted that it had accepted the draft decision to:[854]

- revise the remaining asset lives, due to an error in the way these were calculated in its regulatory proposal
- reduce the accelerated depreciation allowance for Cyclone Larry from $11 million to $10.5 million.

Ergon Energy also updated its RAB for actual capex for 2008–09 and provided a revised capex forecast for 2009–10 in its roll forward model (RFM). These changes affected the remaining lives of each asset class as at 1 July 2010.

Ergon Energy did not accept the draft decision to amortise equity raising costs.[855] However, Ergon Energy did not provide any new arguments in support of its position. It also applied the AER approach to amortising equity raising costs in the PTRM and recalculated a standard asset life for equity raising costs of 48.0 years.

[852] Energex, *Revised regulatory proposal*, January 2010, p. 34.
[853] Energex, *Revised regulatory proposal*, January 2010, p. 26.
[854] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 183.
[855] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 173–174.

10.3 Issues and AER considerations

10.3.1 Standard asset lives

The standard asset lives for the Qld DNSPs are unchanged from those proposed in their regulatory proposals and accepted by the AER in its draft decision. The AER therefore confirms its draft decision and accepts the standard asset lives proposed by the Qld DNSPs. These standard asset lives are reproduced in tables 10.2 and 10.3.

10.3.2 Remaining asset lives

The remaining asset lives were revised by the Qld DNSPs, as a result of:

- Energex — updated its actual capex for 2008–09 and provided a revised forecast for metering capex in 2009–10
- Ergon Energy — updated its actual capex for 2008–09 and revised capex forecasts for 2009–10.

The AER has accepted the revisions made by Energex to its remaining asset lives as contained in its revised regulatory proposal. The AER has also accepted the revisions made to the remaining lives of meters due to revised forecast expenditure on smart meters in 2009-10.[856] The approach Energex has taken to determine its remaining asset lives is consistent with the approach approved in the draft decision.

Ergon Energy revised its remaining asset lives consistent with the approach determined by the AER in the draft decision, which corrected for an error Ergon Energy had made in its regulatory proposal. However, as discussed in chapter 5, the AER made an adjustment to Ergon Energy's RFM, including forecast disposals for 2009–10, which has also affected the remaining asset lives. The AER's calculation of Ergon Energy's remaining asset lives are set out in table 10.3. These remaining asset lives differ marginally from those proposed by Ergon Energy in its revised regulatory proposal.

The AER observes that Ergon Energy had removed all capex (from 2008–09 to 2014–15) associated with the asset category buildings (system) from its revised RFM and PTRM. This change meant that there was no opening RAB value, or remaining asset life, associated with buildings (system) in Ergon Energy's revised regulatory proposal. Ergon Energy explained that in reviewing the draft decision, it identified that it had incorrectly allocated a percentage of forecast capex costs to buildings (system). In its revised regulatory proposal, Ergon Energy stated that it had corrected this error. Ergon Energy also noted that buildings (system) was an asset category in its regulatory accounts to the QCA that ceased being used in 2004–05 when the asset category 'Substation Establishment' was established and the associated asset values were transferred into this category. This came about because the QCA undertook an asset revaluation and the QCA's consultants combined the buildings (system) largely associated with zone substations, into the substation establishment asset category which also includes all site civil works.[857]

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[856] This matter was discussed in chapter 5 of this decision.
[857] Ergon Energy, *email to the AER, Response to AER.ERG.RRP.23*, 2 March 2010.

The AER has accepted Ergon Energy's explanation regarding the treatment of buildings (system). As the asset category is no longer used by Ergon Energy, the AER has deleted this asset category from its analysis and table 10.3.

10.3.3 Equity raising costs

Energex accepted the draft decision to amortise equity raising costs, but Ergon Energy did not. Given that Ergon Energy did not include any new arguments in its revised regulatory proposal in support of its position, the AER has confirmed its draft decision that equity raising costs should be included in the Qld DNSPs' opening RAB and amortised based on a standard asset life.

The AER has recalculated the standard asset lives for the Qld DNSPs' equity raising costs using the same approach as for the draft decision, which was accepted by the Qld DNSPs in their revised regulatory proposals. These standard lives match those calculated by the Qld DNSPs and are set out in tables 10.2 and 10.3.

10.4 AER conclusion

The AER has accepted the standard and remaining asset lives for the Qld DNSPs as set out in tables 10.2 and 10.3.

Table 10.2: AER approved remaining and standard asset lives for Energex (years)

Asset class	Standard life	Remaining life
System assets		
Overhead (OH) sub-transmission lines	51	37
Underground (UG) sub-transmission cables	45	34
OH distribution lines	45	28
UG distribution cables	60	47
Distribution equipment	35	27
Substation bays	45	32
Substation establishment	58	31
Distribution substation switchgear	45	28
Zone transformers	50	40
Distribution transformers	41	30
Low voltage services	35	30
Metering	25	10
Communications- pilot wires	29	19
System buildings	60	59
System easements[a]	na	na
System land[a]	na	na
Non-system assets		
Communications	7	0
Control Centre-System control and data acquisition (SCADA)	12	8
Information technology (IT) Systems	5	5
Office equipment and furniture	7	7
Motor vehicles	9	6
Plant and equipment	7	4
Research and development	5	0
Buildings	40	28
Easements[a]	na	na
Land[a]	na	na
Equity raising costs	46.1	na

(a) These assets are not depreciated and therefore do not have asset lives.

Table 10.3: AER approved remaining and standard asset lives for Ergon Energy (years)

Asset class	Standard life	Remaining life
System assets		
OH sub-transmission lines	55	35
UG sub-transmission cables	45	23
OH distribution lines	50	35
UG distribution cables	60	47
Distribution equipment	35	19
Substation bays	45	33
Substation establishment	60	31
Distribution substation switchgear	45	35
Zone transformers	50	28
Distribution transformers	45	22
Low voltage services	35	4
Metering	25	5
Communications- pilot wires	35	20
Generation assets	30	6
Other equipment	40	37
Control Centre- SCADA	7	4
Land and easements (system)[a]	na	na
Non-system assets		
Communications	30	7
IT Systems	5	2
Office equipment and furniture	7	5
Motor vehicles	10	8
Plant and equipment	10	8
Buildings	40	13
Land and easements[a]	na	Na
Land improvements	40	37
Equity raising costs	48.0	na

(a) These assets are not depreciated and therefore do not have asset lives.

On the basis of the AER's approved asset lives, opening RAB, and forecast capex allowance, the AER determines the Qld DNSPs' regulatory depreciation allowances for the next regulatory control period, as set out in table 10.4.

Table 10.4: AER conclusion on regulatory depreciation for the Qld DNSPs ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014-15	Total
Energex	78.5	87.2	98.1	110.2	111.5	485.5
Ergon Energy	145.0	146.9	150.3	164.1	144.6	750.9

Note: Regulatory depreciation represents the net effect of the straight line depreciation of the Qld DNSPs' assets and the indexation of those assets due to inflation.
These depreciation allowances included equity raising costs that were amortised.
The depreciation allowance for Ergon Energy does not include its accelerated depreciation claim for destroyed assets. These assets are accounted for separately in the PTRM.

10.5 AER decision

In accordance with clause 6.12.1(8) of the NER the AER has not accepted the depreciation allowances submitted by Energex. The AER has determined the depreciation allowances for Energex set out in table 10.4 of this decision.

In accordance with clause 6.12.1(8) of the NER the AER has not accepted the depreciation allowances submitted by Ergon Energy. The AER has determined the depreciation allowances for Ergon Energy set out in table 10.4 of this decision.

11 Cost of capital

This chapter sets out the AER's consideration of the rate of return for the Qld DNSPs for the next regulatory control period, and deals with issues raised in the Qld DNSPs' revised regulatory proposals and submissions—specifically the determination of the risk–free rate, debt risk premium (DRP) and inflation forecast.

11.1 AER draft decision

The AER's statement of regulatory intent (SORI) defines a number of the weighted average cost of capital (WACC) parameter values to be adopted by the Qld DNSPs for the purposes of setting a rate of return, unless there is persuasive evidence for a departure from the SORI. This persuasive evidence could be on the basis of a material change in circumstances or any other relevant factor.[858] For the parameters where the values are calculated based upon a method—the nominal risk–free rate and the DRP—the SORI sets out the method to be used by the AER for determining the values.

The Qld DNSPs adopted the WACC parameters specified in the SORI for the equity beta, market risk premium (MRP), gearing ratio and credit rating.[859] The AER noted the acceptance of these parameters.[860]

The AER calculated an indicative nominal vanilla WACC of 10.06 per cent for the Qld DNSPs. The indicative WACC was higher than that proposed by the Qld DNSPs because the risk–free rate and DRP had increased since the time the Qld DNSPs prepared their proposals. The WACC determined by the AER did not include a proposed convenience yield.

Table 11.1 outlines the WACC parameter values for the draft decision. The AER noted that it would update the nominal risk–free rate and DRP, based on the agreed averaging period, and update the expected inflation rate at a time closer to the Qld DNSPs' final distribution determinations.

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858 NER, clause 6.5.4(h).

859 AER, *Electricity transmission and distribution network service providers, Statement of revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution)*, 1 May 2009; Energex, *Regulatory proposal*, July 2009, p. 245 and Ergon Energy, *Regulatory proposal*, July 2009, p. 389.

860 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 228–235, 257–262, 265.

Table 11.1: AER draft conclusion on WACC parameters

Parameter	Energex	Ergon Energy
Nominal risk–free rate	5.44%	5.44%
Real risk–free rate	2.92%	2.92%
Expected inflation rate	2.45%	2.45%
Gearing level (Debt:Equity)	60:40	60:40
Market risk premium	6.5%	6.5%
Equity beta	0.8	0.8
Debt risk premium	4.24%	4.24%
Nominal pre-tax return on debt	9.68%	9.68%
Nominal post-tax return on equity	10.64%	10.64%
Nominal vanilla WACC	10.06%	10.06%

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 282.

11.2 Revised regulatory proposals

The Qld DNSPs adopted a nominal vanilla WACC of 10.06 per cent for modelling purposes, consistent with the draft decision.[861]

Energex noted that it did not agree with aspects of the draft decision, made specific comments on the debt risk premium, and stated that it did not have any other new evidence to submit.[862]

Ergon Energy stated that it did not accept the draft decision in relation to WACC in its entirety, made specific comments with regard to the nominal risk–free rate, debt risk premium and expected inflation, and re-proposed all parameter values from its regulatory proposal.[863]

11.3 Submissions

On 15 February 2010, Energex made a submission on its revised regulatory proposal.[864] Energex submitted that the risk–free rate applied over the entire five year regulatory control period should not be set during abnormal market conditions.[865] Energex stated that the AER has not responded to elements of its initial proposal

[861] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 281–282; Energex, *Revised regulatory proposal*, January 2010, p 37; and Ergon Energy, *Revised regulatory proposal*, 14 January 2010, p. 188.

[862] Energex, *Revised regulatory proposal*, January 2010, p 37

[863] Ergon Energy, *Revised regulatory proposal*, 14 January 2010, p. 188.

[864] Energex, *Submission on draft determination*, February 2010.

[865] Energex, *Submission on draft determination*, February 2010, pp. 14–15.

regarding the DRP. To calculate the DRP, Energex suggested an average of Bloomberg and CBASpectrum data sources be used instead of only CBASpectrum.[866] Energex also noted issues—consistent with comments by the AER in the draft decision—regarding the possible change to inflation estimation methodology, and the verification of liquidity in the market for indexed Commonwealth government securities (CGS).[867]

The Energy Users Association of Australia (EUAA) submitted that the allowed cost of capital was too high, noting that it had already submitted this information to the AER as part of the review of WACC parameters.[868] In addition, the EUAA noted a paper by Mountain and Littlechild which found that the cost of capital set by Ofgem for regulated utilities in the United Kingdom (UK) was lower than the draft decision for the Qld DNSPs. The EUAA considered that in the context of international capital markets there was no valid reason why the cost of capital should be higher in Australia.

11.4 Issues and AER considerations

11.4.1 Nominal risk–free rate

AER draft decision

The AER determined a nominal risk–free rate of 5.44 per cent (effective annual compounding rate) in the draft decision. This was based on the average across the 40 business days from 19 August 2009 to 13 October 2009 for CGS yields with a 10–year maturity, using indicative mid-rates published by the Reserve Bank of Australia (RBA). The AER agreed to the Qld DNSPs' proposed averaging period to estimate the risk–free rate and that the start and end dates would remain confidential until the expiration of the period. The AER noted that the risk–free rate would be updated, based on the agreed averaging period, at the time of the final decision.[869]

Revised regulatory proposals

The Qld DNSPs' revised regulatory proposals have adopted the methodology for calculating the nominal risk–free rate set out in the AER draft decision.

Ergon Energy stated that it has adopted this methodology for modelling purposes but maintains that its June 2009 regulatory proposal for inclusion of a convenience yield remains appropriate.[870]

Energex has agreed that an adjustment to the risk–free rate—such as a convenience yield—is currently not necessary.[871]

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866 Energex, *Submission on draft determination*, February 2010, p. 15.
867 Energex, *Submission on draft determination*, February 2010, p. 16.
868 This statement is not referenced to a particular WACC review submission. EUAA, *Submission to the AER on QLD DNSPs*, February 2010, p. 6.
869 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 256.
870 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 186.
871 Energex, *Revised regulatory proposal*, January 2010, p 37.

Submissions

Energex considered that the risk–free rate should not be set during abnormal market conditions, and noted that major economic shocks before the AER's final decision could cause an abnormal risk–free rate to persist for the next regulatory control period.[872]

The EUAA stated that the Qld DNSPs were not funded through Commonwealth government gilts, and that it was therefore inappropriate to set the risk–free rate based on Australian CGS. The EUAA submitted that the risk–free rate component of both the cost of equity and the cost of debt should be set with regard to international capital markets, where much cheaper capital was available.[873]

AER considerations

The AER notes that although Ergon Energy does not agree with the draft decision on the risk–free rate, it has not submitted any new evidence on this matter.[874] The AER therefore considers that its draft decision deals with all relevant material raised by Ergon Energy,[875] and confirms that there is no persuasive evidence justifying a departure from the SORI.

The AER notes that although Energex has withdrawn its proposal for the risk–free rate to include a convenience yield, it has made this contingent upon the absence of economic shocks that result in the return of abnormal market conditions.[876] The AER notes Energex does not define economic shocks or the criteria for how abnormal market conditions are to be assessed. In the absence of such fundamental information on how such events are to be assessed the AER does not consider it reasonable to further consider this matter. In any case, taking into account the prevailing conditions in the market for funds, the AER considers that the methodology specified in the SORI when applied to the agreed averaging period provides an unbiased estimate of expected returns.

The AER considers that the proposal by the EUAA to set the risk–free rate with regard to international capital markets is not consistent with the basis on which other parameters of the cost of capital are estimated. That is, the AER applies a domestic CAPM,[877] deriving estimates of all WACC parameters on this basis, and it would be invalid to change one component of the WACC equation in isolation.[878] The AER also notes that submissions from user groups to the WACC review were given appropriate consideration as part of that process.

The AER updates the risk–free rate based on the averaging period proposed by the Qld DNSPs and agreed to by the AER. For this decision, the AER determines the risk–free rate, based on the average across 40 business days from 1 February 2010 to

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872 Energex, *Submission on draft determination*, February 2010, pp. 14–15.
873 EUAA, *Submission to the AER on QLD DNSPs*, February 2010, pp. 6–7.
874 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 186.
875 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 232–254.
876 Energex, *Submission on draft determination*, February 2010, pp. 14–15.
877 AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, 1 May 2009, pp. 97–101.
878 The EUAA also proposed changing the allowed rate of return to be based on an international cost of capital model—this is considered in section 11.4.4.

26 March 2010 (inclusive) for CGS yields with a 10–year maturity, using indicative mid-rates published by the Reserve Bank of Australia (RBA). The resulting nominal risk–free rate is 5.64 per cent (effective annual compounding rate). The AER has determined the nominal risk–free rate in accordance with clauses 6.5.2(c)–(d) of the NER and the SORI.

11.4.2 Debt risk premium

AER draft decision

The AER determined a DRP of 4.24 per cent. The AER considered the use of CBASpectrum's BBB+ fair value curve provided the best available prediction of observed yields for purposes of determining the DRP on the benchmark BBB+ 10–year corporate bond, with respect to the indicative averaging period used in the draft decision.

Revised regulatory proposals

The Qld DNSPs adopted the DRP of 4.24 per cent outlined in the draft decision, but noted concerns regarding the determination of this value.

Energex reiterated the view stated in its regulatory proposal that the midpoint between the Bloomberg and CBASpectrum fair value curves is a good approach to measuring the cost of debt. Energex stated that the AER is yet to address the method that it will use to estimate a 10–year rate from Bloomberg following the cessation of publication of the 10–year BBB and A fair value yields.[879]

Ergon Energy stated the draft decision created uncertainty over the source of information for determining the DRP in the final determination. Further, Ergon Energy noted there was no clear statement on how the 10–year Bloomberg BBB estimate would be determined, and proposed two methods:

- linear extrapolation method—extrapolating the 7–year Bloomberg BBB rate based on the difference between the 5–year and 7–year Bloomberg BBB yields
- credit rating extrapolation method—adding the difference between the 7–year and 10–year Bloomberg AAA yields to the 7–year Bloomberg BBB yield.

Ergon Energy stated it does not accept the draft decision for the calculation of the DRP but has used the value for modelling purposes in its revised regulatory proposal.[880]

Submissions

The EUAA submitted that the benchmark firm would have access to international capital markets and the AER inappropriately set the DRP by referencing the (higher) cost of debt in Australian capital markets. To demonstrate this point, the EUAA noted that Ofgem recently estimated the cost of debt at 3.6 per cent (real), based on the cost for UK distribution networks to access international bonds. The EUAA also presented

879 Energex, *Revised regulatory proposal*, January 2010, p. 37.
880 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 186.

a February 2010 research note from Credit Suisse, which indicated that SP AusNet sourced offshore debt at a DRP of 280 basis points less than the DRP set by the AER in the ETSA Utilities draft decision. The EUAA considered this was a clear case of overcompensation, and the AER was in error to set the benchmark compensation based upon the Australian cost of debt.[881]

Energex submitted that an average of the CBASpectrum and Bloomberg fair value curves should be used in place of only the CBASpectrum fair value curve. Energex submitted that there were two matters from its regulatory proposal that the AER has failed to respond to in the draft decision:[882]

- how a 10–year Bloomberg BBB yield will be estimated
- the method that the AER currently use to test alternative data sources available.

Energex recommended, supported by advice from Synergies Economic Consulting (Synergies),[883] that an average of the linear extrapolation method and the credit rating extrapolation method be used to estimate the 10–year Bloomberg BBB yield.

Further, Energex—based on Synergies' analysis—stated further refinements should be made to the AER's method used to test the alternative data sources to minimise analytical subjectivity.[884] Synergies specifically identified that the AER should:[885]

- make a clear statement as to what constitutes an outlier to remove the subjectivity with the current approach
- change its approach and consider spreads as opposed to yields to increase the credibility of the results of the model
- reconsider the weighting of bonds in the sample analysis so that longer dated bonds could have a greater weighting than shorter dated bonds.

AER considerations

The AER notes that the DRP is set with regard to the Australian benchmark BBB+ corporate bond rate. The (isolated) experience of a particular business's (SP AusNet) recent capital raising are not directly relevant but experience of individual businesses will be reflected in the fair value curve that is used to establish the benchmark DRP. Further, as discussed above, the proposal by the EUAA to set the DRP with regard to international capital markets is not consistent with the basis on which the other parameters of the cost of capital are estimated. That is, the AER applies a domestic

881 EUAA, *Submission to the AER on QLD DNSPs*, February 2010, pp. 6–7.
882 Energex, *Submission on draft determination*, February 2010, p. 15.
883 Synergies, *Issues relating to cost of capital: Response to AER's draft decision*, February 2010, pp. 19–20. Submitted as appendix 4 to Energex, *Submission on draft determination*, February 2010.
884 Energex, *Submission on draft determination*, February 2010, p. 15.
885 Synergies, *Cost of capital issues*, February 2010, pp. 20–22.

CAPM,[886] deriving estimates of all WACC parameters on this basis, and it would be invalid to change one component of the WACC equation in isolation.[887]

In order to estimate the benchmark DRP the AER must decide which data source (Bloomberg, CBASpectrum or an average of the two) in respect of the fair value curve is to be used. In this section the AER's standard methodology to select between these data sources is outlined. Refinements and augmentations to the approach are considered. Finally, the method, including any refinements or augmentations, is applied to select a data source and estimate the benchmark DRP.

AER standard methodology to select a fair value curve

The data source used to estimate the DRP is selected by:

1. Defining a population of corporate bonds that closely reflect the characteristics of bonds that would be issued by the benchmark DNSP.[888]
2. Considering whether any of these bonds should be excluded from the analysis on the basis that the yields for these bonds are not representative of their credit rating.
3. Comparing the observed yields of this sample of bonds to the fair value curves of CBASpectrum, Bloomberg and an average of the two curves, in order to determine which curve aligns most closely to the observed yields.

The population of bonds is defined as BBB+ fixed rate corporate bonds,[889] with a term to maturity over two years, issued in Australia by Australian companies with observations available from Bloomberg, CBASpectrum and UBS over the agreed averaging period. The AER excludes bonds from the population where information is not available from all three data sources to ensure consistency and completeness of the data used in later steps.

The AER then considers whether any of the bonds in the population should be excluded from the analysis because the yields for the particular bonds are not representative of their credit rating. To do this the AER uses graphs of yields of the sample of bonds over time to identify any anomalies. If anomalous bonds are identified then that bond's yields are tested using the Chow test. The Chow test is used to identify whether the anomaly is statistically significant, which may indicate an outlier.

The Chow test is commonly used to determine the existence of a sudden and permanent change in the data sets—it compares two time periods to determine if they have the same explanatory factors.[890] If the change is statistically significant then the AER considers relevant market developments to assess whether a fundamental shift in

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886 AER, *Final decision, WACC parameters*, May 2009, pp. 97–101.

887 The EUAA also proposed changing the allowed rate of return to be based on an international cost of capital—this is considered in section 11.4.4.

888 BBB+ fixed rate corporate bonds, with a term to maturity over two years, issued in Australia by Australian companies with observations available from Bloomberg, CBASpectrum and UBS over the averaging period.

889 Consistent with the credit rating set out in the SORI.

890 G. Chow, *Tests of equality between sets of coefficients in two linear regressions*, Econometrica, July 1960, vol. 28(3).

the market perception of the business has occurred. A bond may be excluded from the sample and assessed as an outlier after consideration of these matters.

The bonds left after excluding such outlying bonds are referred to as the sample of bonds. The sample of bonds is used to conduct the comparison of observed yields to the fair value curves of CBASpectrum, Bloomberg and an average of the two curves. The comparison is conducted using the weighted sum of squared errors.[891] The weighted sum of squared errors is a mathematical formula which provides a measure of how closely each fair value curve fits to observed bond yields. A smaller value indicates a better fit.

A similar approach to that described above was reviewed by the Australian Competition Tribunal (Tribunal) which found that there was no compelling case for departing from the AER's methodology.[892] The Tribunal also noted that the AER needs to reconsider the data sources and methodology in future determinations.[893] The AER has reconsidered its methodology and has made some refinements, as described below.

The AER considers that selecting a fair value curve that most closely aligns to the observed yields in the sample of bonds is a reasonable approach to estimating a benchmark DRP, consistent with clause 6.5.2(e) of the NER.

Refinements and augmentations to the AER standard methodology

The Qld DNSPs' revised regulatory proposals and submission raise the following issues in response to the draft decision:

- the extrapolation of Bloomberg's BBB fair value curve from a term of seven years to 10 years
- removal of subjectivity regarding the method used to determine which bonds in the population should be excluded from the sample of bonds for analysis
- the weighting of bonds and if longer dated bonds could have a greater weighting than shorter dated bonds.

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891 The weighted sum of squared errors is defined as:

$$WSSE = \frac{1}{n}\sum_{i=1}^{n}\left\{\left[\sum_{j=1}^{t_i}\left(Observed_{i,j} - Fair_{i,j}\right)^2\right]\frac{1}{t_i}\right\}$$

Where:

n is the number of bonds in the sample

t_i is the number of observations for the ith bond

$Observed_{i,j}$ is the jth observed yield for the ith bond, taken from either Bloomberg, CBASpectrum or UBS

$Fair_{i,j}$ is the jth fair yield for the ith bond, taken from either Bloomberg, CBASpectrum or an average of the two.

892 Australian Competition Tribunal, *Application by Energy Australia and other [2009] ACompT8*, November 2009, p. 39.

893 Australian Competition Tribunal, *Application by Energy Australia and other [2009] ACompT8*, November 2009, p. 39.

Extrapolation of Bloomberg BBB fair value curve
On 9 October 2007 Bloomberg ceased publishing values for the BBB fair value curve beyond a term of eight years. This required the AER to establish a method to extrapolate the fair value curve from a term of eight to 10 years. In order to do this the AER added the spread between the 8–year and 10–year Bloomberg A fair value estimates to the 8–year Bloomberg BBB fair value estimate.[894]

On 19 August 2009 Bloomberg ceased publishing both its BBB and A rated fair yield estimates beyond a term of seven years. Consequently, the AER can no longer use the Bloomberg A fair value curve to extrapolate the Bloomberg BBB fair value curve to 10 years.

The AER considers a number of possible data sources for overcoming this data limitation:

- Bloomberg AA and AAA fair value curves
- Bloomberg CGS fair value curve
- Bloomberg semi-government fair value curves (NSW, VIC, QLD and WA)
- Bloomberg's interest rate swaps curve
- a linear extrapolation based on the spread between the 5–year and 7–year Bloomberg BBB fair value estimates.

For the first four of these sources the difference between the 7–year and 10–year yield is used to extrapolate the Bloomberg BBB fair value curve to a term of 10 years. For the last source the difference in the term to maturity between the yields is only two years so the spread is multiplied by 1.5 to estimate a three year spread.

The AER evaluates these options by comparing each extrapolated 10–year fair value curve to the Bloomberg BBB fair value curve over the period from 10 November 2005 to 9 October 2007. This period is selected because it represents the most recent period for which the 10–year Bloomberg BBB fair value curve is available.

The difference between the extrapolated curve and the actual Bloomberg BBB fair value curve on each day during the period is squared and averaged over this period. This measurement is called the mean squared difference. A lower mean squared difference indicates a more accurate extrapolation. That is, the lowest mean squared difference indicates the best estimate of the fair value curve possible in the circumstances. The results of this analysis are shown in table 11.2.

[894] Bloomberg's BBB fair value estimates are assumed to approximate BBB+ fair values estimates due to the estimation technique employed and the market being disproportionately weighted with BBB+ rated bonds.

Table 11.2: Results of testing of extrapolation methods

	Mean squared difference
Bloomberg AA	na[a]
Bloomberg AAA	0.0025
Bloomberg CGS	0.0041
Bloomberg NSW	0.0048
Bloomberg VIC	0.0053
Bloomberg QLD	0.0047
Bloomberg WA	0.0049
Bloomberg interest swaps	0.0047
Linear	0.0122

(a) This data is unavailable as Bloomberg did not publish a AA fair value curve over the required term of maturities during the period under consideration.

Based on this analysis, the AER considers that the spread between the 7–year and 10–year Bloomberg AAA fair value estimates provides a reasonable approach to extrapolating the Bloomberg BBB fair value curve to a term of 10 years.

Determining which bonds to exclude from the sample

Under the AER's standard methodology, even though a bond may be eligible for inclusion in the sample of bonds because it has certain characteristics[895] it may be excluded from the sample if it is identified as not being representative of a BBB+ rated bond. This may be the case if the observed yield on the bond makes it an outlier. Synergies, in its report provided by Energex, has asked for a clear statement about what it considers to be an outlier.[896] The revised approach adopted by the AER to identifying outliers is outlined below.

Based on a CEG report on the bond sample and the Synergies report,[897] three statistical tests to determine whether the observed yield on a bond is an outlier were proposed:[898]

895 BBB+ fixed rate corporate bonds, with a term to maturity over two years, issued in Australia by Australian companies with observations available from Bloomberg, CBASpectrum and UBS over the averaging period.

896 Synergies, *Cost of capital issues*, February 2010, pp. 21–22

897 The CEG report was submitted to the AER as part of the concurrent review of the South Australian distribution network service provider, ETSA Utilities. CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates, A report for ETSA Utilities*, January 2010 and Synergies, *Cost of capital issues*, February 2010.

898 CEG, *Testing fair value estimates*, January 2010, pp. 16–18, and Synergies, *Cost of capital issues*, February 2010, p. 21.

- Chauvenet's test—an observation is an outlier if it lies outside a confidence interval of the mean with a level of significance of 1/2n where n is the number of observations in the sample
- classic outlier test—an observation is an outlier if it lies further than two standard deviations from the mean
- box plot test—an observation is an outlier if it exceeds the 75th percentile by 1.5 times the interquartile range or lies below the 25th percentile by 1.5 times the interquartile range.

The AER considers CEG and Synergies' approaches of testing the spreads to CGS and not absolute yields, is appropriate and the AER has augmented its methodology for identifying outliers to include this suggestion.[899]

The AER also considers that the three tests suggested by CEG can be used to augment the AER's approach to identifying outliers.

Weighting of bonds in sample

Synergies suggested that bond weightings be considered with regard to maturities—with longer dated bonds having a greater weighting in the sample analysis. It is suggested by Synergies that this practice of weighting be implemented until bonds with maturities of at least 10 years can be included in the sample for analysis.[900]

The AER considers this suggestion has merit. For example, if two fair value curves matched observed yields equally, the curve that more accurately reflected the longer dated bonds would be preferred, and a weighting could encapsulate this.

Any weighting, however, would be subjective, as is pointed out by Synergies, and it is unclear what range a 'correct' value would hold, nor its mathematical form.[901]

As no specific recommendation has been made by Synergies, and considering the subjectivity involved, no weighting based on maturity has been added to the DRP estimation methodology.

Selection of the fair value curve using the AER methodology

Step 1 of the AER's methodology is to identify the population of BBB+ bonds from which the sample of bonds is drawn. For this final decision, the relevant population of BBB+ bonds is set out in table 11.3.

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899 CEG, *Testing fair value estimates*, January 2010, pp. 15–16, and Synergies, *Cost of capital issues*, February 2010, p. 21.

900 Synergies, *Cost of capital issues*, February 2010, pp. 21–22.

901 Synergies, *Cost of capital issues*, February 2010, p. 22

Table 11.3: Population of BBB+ rated corporate bonds

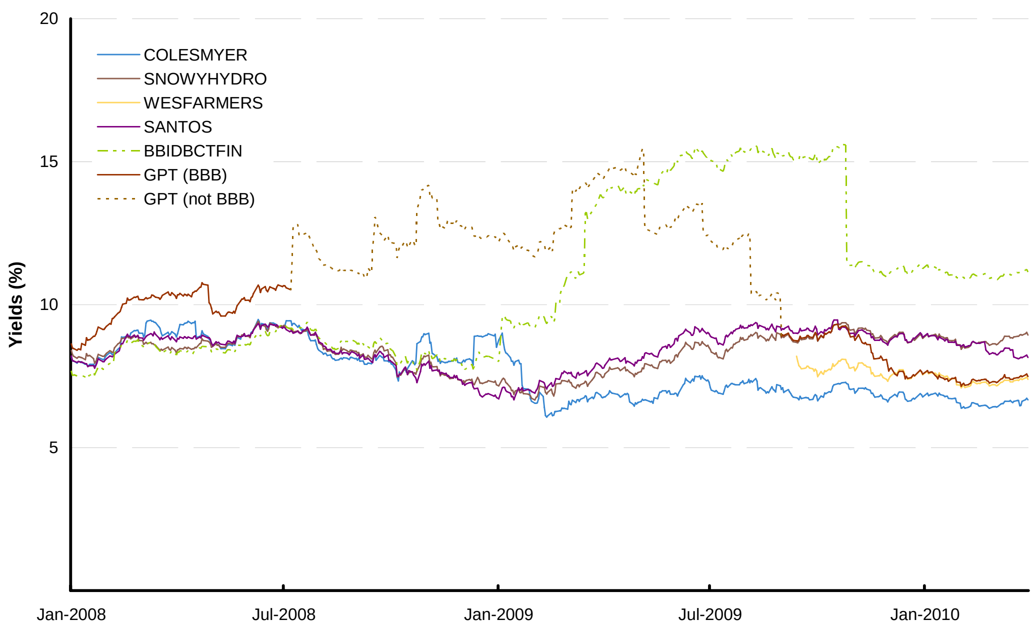
Issuer	Matures on	International securities identification number
Coles Myer	25 July 2012	AU300CML1014
Snowy Hydro	25 February 2013	AU000SHL0034
GPT	22 August 2013	AU300GPTM218
Wesfarmers	11 November 2014	AU3CB0126860
Santos	23 September 2015	AU300ST50076
Babcock and Brown Infrastructure	9 June 2016	AU300BBIF018

Source: Bloomberg, CBASpectrum, UBS Rate sheet.

In step 2, as outlined above, prior to selecting the appropriate fair value curve, the AER identifies outliers in the population of bonds to determine the relevant sample of bonds for analysis.

On examination of the data, the AER considers the period beginning in early 2009 may represent a structural change impacting the underlying value of the Babcock and Brown Infrastructure (BBI) bond.

Figure 11.1: Yields on the population of BBB+ bonds—UBS



Source: UBS, Rate sheets 1 January 2007–26 March 2010.

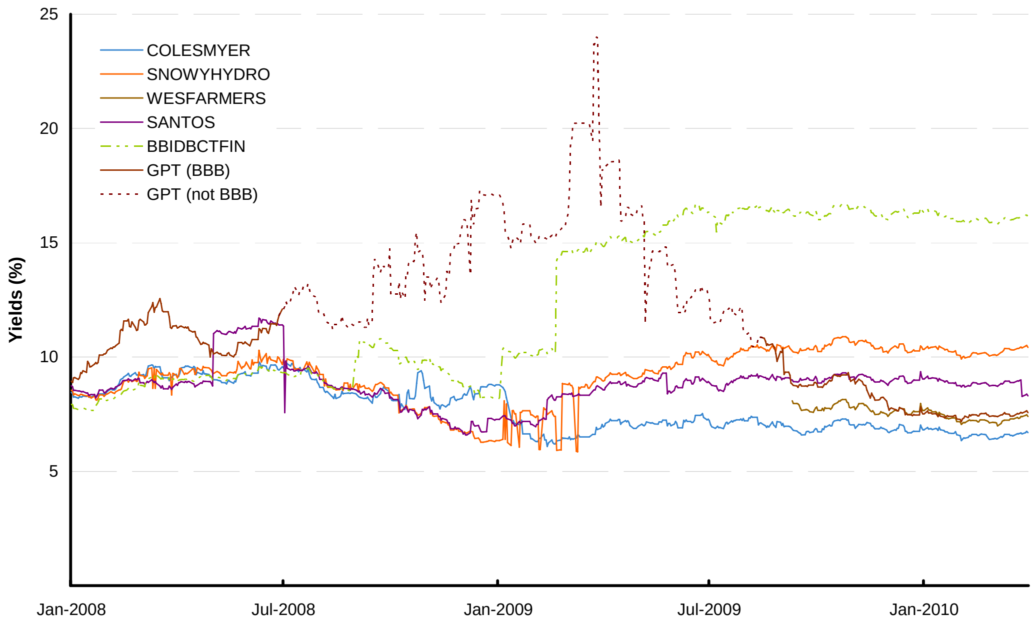
As shown in figure 11.1, based on data from UBS, the average observed yield for the BBI bond was around 7.5 per cent between January 2008 and December 2008. This increased significantly to around 13 per cent between December 2008 and March 2009. Based on this initial inspection, the Chow test on the spread between the yields on the BBI bond and CGS indicates that the change in yield is statistically significant.

The AER also considers market developments in late 2008 and early 2009, which include the voluntary suspension of trading in Babcock and Brown shares and attempts to de–link Babcock and Brown and its associated companies, are likely to affect the reliability of the observed yield for the BBI bond.[902]

Using the augmentations to the AER's standard methodology as suggested by CEG, Chauvenet's test, the classical outlier test and the box plot test all indicate that after late 2008, the yield on the BBI bond is an outlier when compared to other bonds in the population.

The AER also compared the UBS data with the data from CBASpectrum, as shown in figure 11.2. This review shows that the BBI yield observed from CBASpectrum also exhibits a structural change in early 2009, although it does not exhibit the second period of structural change in late 2009 that is observed in the UBS data.

Figure 11.2: Yields on the population of BBB+ bonds—CBASpectrum



Source: CBASpectrum.

The AER considers that this provides additional evidence that even in late 2009 there is significant divergence in yields for the BBI bond, as reported by CBASpectrum and UBS, suggesting the observed yield for this bond is unreliable and cannot be included in the sample for analysis.

As a result of this analysis, the AER considers that the BBI bond should be excluded from the sample of BBB+ rated bonds that is used in the comparison of fair value curves to observed yields.

Once the sample of bonds is identified, the AER tests the sample of observed bond yields against the fair value estimates from Bloomberg and CBASpectrum.

902 Babcock and Brown, *Suspension from official quotation*, 12 January 2009.

Table 11.4 outlines the average bond yields observed from Bloomberg, CBASpectrum and UBS, and average fair value estimates for the sample of bonds over the averaging period, 1 February to 26 March 2010.

Table 11.4: Sample of BBB+ bonds—observed yields and fair values between 1 February and 26 March 2010 (per cent)

Issuer	Average observed yield			Average fair value	
	Bloomberg	CBASpectrum	UBS	Bloomberg	CBASpectrum
Coles Myer	6.54	6.54	6.50	7.30	7.21
Snowy Hydro	8.53	10.19	8.71	7.50	7.53
GPT	7.32	7.45	7.35	7.73	7.71
Wesfarmers	7.26	7.22	7.26	8.34	8.04
Santos	8.81	8.82	8.43	8.82	8.27

Source: Bloomberg, CBASpectrum, UBS, AER analysis.

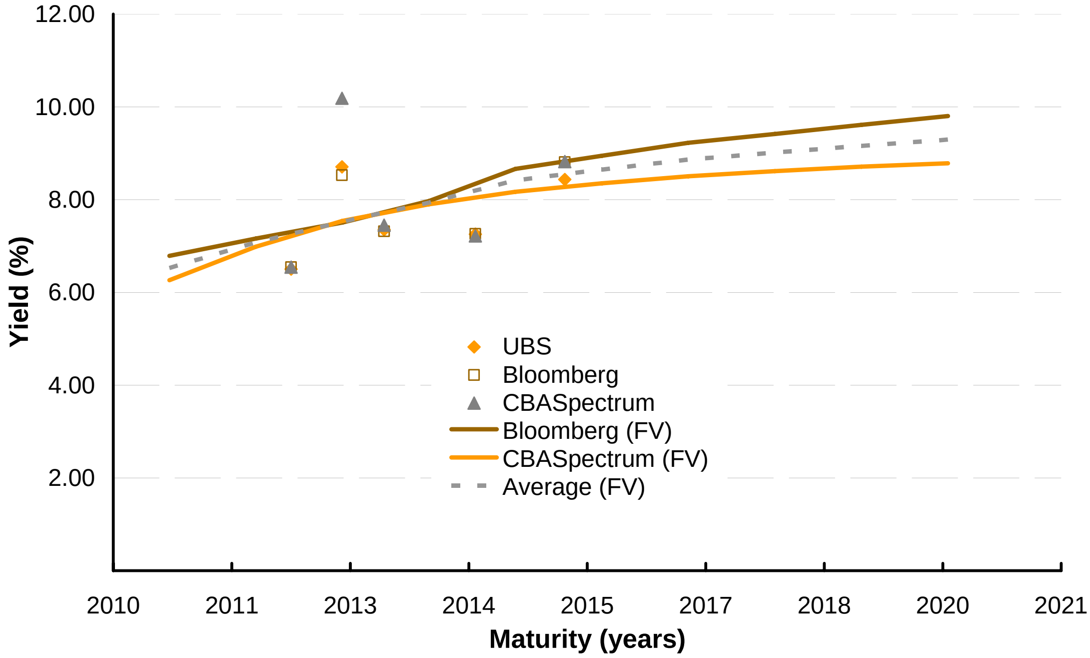
The observed yields were compared to the Bloomberg BBB fair value curve, the CBASpectrum BBB+ fair value curve and an average of the two curves using the weighted sum of squared errors. Table 11.5 and figure 11.3 show the results.

Table 11.5: Fair value and observed yield analysis using weighted sum of squared errors between 1 February and 26 March 2010 (per cent)

		Fair value source		
		Bloomberg	CBASpectrum	Average
Observation source	UBS	0.72	0.54	0.61
	Bloomberg	0.63	0.54	0.57
	CBASpectrum	1.83	1.71	1.75

Source: Bloomberg, CBASpectrum, UBS, AER analysis.

Figure 11.3: Fair value and observed yield analysis based on BBB+ bond sample



Source: Bloomberg, CBASpectrum, UBS, AER analysis.

CBASpectrum's BBB+ fair value curve best matches the observed yields. This is because CBASpectrum's BBB+ fair value curve has the smallest weighted sum of squared errors no matter which data source is used for the observed bond yields. The weighted sum of squared errors is a mathematical formula which provides a measure of how closely each fair value curve fits to observed bond yields. A smaller value indicates a better fit. Therefore, the AER considers that CBASpectrum's BBB+ fair value curve provides estimates which are more closely aligned to observed yields for a sample of BBB+ bonds.

Summary

Based on its analysis conducted over the averaging period, using the AER's methodology, augmented for additional tests as suggested by CEG and Synergies, the AER considers that CBASpectrum's fair value curve provides estimates which are more closely aligned to observed yields for a sample of BBB+ bonds. The AER's approach has been put in place to reduce the need for an arbitrary selection of the data source used to estimate the DRP.

The AER considers that its approach results in an estimate of the benchmark DRP consistent with clause 6.5.2(b) of the NER, under which the rate of return for a DNSP is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the Qld DNSPs.

The AER determines the benchmark DRP by averaging the yield on a 10–year BBB+ corporate bond over the averaging period of 40 business days between 1 February 2010 and 26 March 2010 (to match the period used for estimating the risk–free rate). The resulting DRP is 3.33 per cent (effective annual compounding rate). Adding this

DRP to the risk–free rate of 5.64 per cent provides a return on debt of 8.98 per cent.[903]

The AER is satisfied that the DRP is consistent, under clause 6.5.2(e) of the NER, with the margin between the annualised nominal risk–free rate and the observed annualised Australian benchmark corporate bond rate corresponding to BBB+ credit rating and maturity of 10 years.

11.4.3 Expected inflation rate

AER draft decision

The AER determined a 10–year inflation forecast of 2.45 per cent per annum, consistent with the period adopted for the WACC parameters. The inflation forecast was based on a geometric average of the RBA's forecasts of short–term inflation—currently extending out to two years—and the mid–point of the RBA's target inflation band for the remaining years in the 10–year period. This methodology was deemed likely to result in the best forecast available.[904] The AER observed that the proposals from the Qld DNSPs were broadly consistent with this methodology apart from the use of an arithmetic average instead of a geometric average. The AER noted that the inflation forecast would be updated using the latest forecasts at the time of the final decision.[905]

The AER also noted that it would re-examine the use of market implied inflation forecasts—derived from the comparison of nominal fixed interest CGS with inflation indexed CGS—at the time of the final decision.[906]

Revised regulatory proposals

The Qld DNSPs have accepted the inflation rate methodology set out in the draft decision. The Qld DNSPs expressed concern regarding the future assessment of the liquidity of indexed CGS and a potential change in methodology for calculating the expected inflation rate at the final decision stage of the regulatory process.[907]

Energex acknowledged the use of an arithmetic average in their original regulatory proposal was unintended.[908] Ergon Energy accepted the change to a geometric average from its preferred arithmetic average, based on the immaterial difference between the two approaches.[909]

Submissions

Energex submitted that the market for inflation indexed CGS may not produce an efficient price discovery process. Energex stated that if the AER proposed to use this market data to derive the expected inflation rate, it must establish that it is credible

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903 Figures do not add up due to rounding.
904 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 280.
905 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 280.
906 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 279-280.
907 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 187; and Energex, *Revised regulatory proposal*, January 2010, p. 40.
908 Energex, *Revised regulatory proposal*, January 2010, p. 40.
909 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 187.

and reliable. Some examples of tests to establish credibility were proposed by Synergies.[910]

AER considerations

In forecasting inflation, the AER is guided by the NER requirement that the appropriate methodology should result in the best estimate of expected inflation.[911] The AER confirms its draft decision that the best estimate of expected inflation is represented by the methodology based on the average of RBA forecasts and targets, as outlined in the draft decision.[912]

With the issuance of indexed CGS by the Australian Office of Financial Management resuming in September 2009, the AER is continuing to assess the functionality of the market for these securities.[913] As the AER would prefer the use of an objective market based inflation forecasting methodology, the historically adopted approach—calculated as the difference between the nominal CGS yield and the indexed CGS yield—will be reassessed for future determinations.

For this decision, the AER updates the inflation forecast for the first two years of the next regulatory control period using the latest published RBA inflation expectations as shown in table 11.6.[914] The methodology used to derive the best estimate of expected inflation is consistent with that outlined in the draft decision and accepted by the Qld DNSPs. Based on this methodology, the AER considers that an inflation forecast of 2.52 per cent per annum produces the best estimate for a 10 year period.

Table 11.6: AER conclusion on inflation forecast (per cent)

	June 2011	June 2012	June 2013	June 2014	June 2015	June 2016	June 2017	June 2018	June 2019	June 2020	Geometric average
Forecast inflation	2.50	2.75	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.52

Source: RBA, Statement on monetary policy, 4 February 2010, p. 58.

11.4.4 Overall cost of capital

AER draft decision

In the draft decision the AER considered whether the individual components and the resulting overall rate of return would contribute, or be likely to contribute, to the achievement of the national electricity objective. This included evaluation of the relative values of the return on equity and the return on debt.[915]

910 Energex, *Submission on draft determination*, February 2010, p. 16.
911 NER, clause 6.4.2(b)(1).
912 AER, *Final decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April 2009, p. xxi; and AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. xxxviii.
913 AOFM, *Issuance program*, 5 November 2009, viewed 9 March 2010, http://www.aofm.gov.au/content/borrowing/calendar.asp
914 RBA, *Statement of Monetary Policy*, 4 February 2010, p. 58.
915 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 239–257.

Based on a nominal risk–free rate of 5.44 per cent, the nominal pre-tax rate of return on debt was 9.68 per cent, the nominal post-tax rate of return on equity was 10.63 per cent, and the overall nominal vanilla WACC was 10.06 per cent. The AER considered that both its approach and these values would contribute, or be likely to contribute, to the achievement of the national electricity objective.[916]

Revised regulatory proposals

Energex submitted, with reference to a report by Strategic Finance Group (SFG), that the AER's dismissal of Energex's cost of equity analysis was unreasonable. SFG identified problems with some statements and assumptions made by the AER in the draft decision.[917]

Submissions

The EUAA submitted that the allowed cost of capital was too high, noting that it had already submitted this information to the AER as part of the review of WACC parameters.[918] In addition, the EUAA considered that evidence from the UK showed a lower overall cost of capital and that the AER should set its benchmark rate of return with regard to international capital markets. The EUAA stated that the AER must justify its use of an equity beta of 0.8 since it is higher than the equity beta of 0.2 Ofgem allows for UK regulated electricity networks.[919] Further, the EUAA noted that the UK distribution networks accepted the Ofgem proposals, inferred that this meant the rate of return estimated by Ofgem was appropriate (or more than appropriate), and argued by extension that the AER's rate of return was too high.

AER considerations

In the draft decision the AER outlined the regulatory requirements, revenue and pricing principles and its considerations that are of particular relevance to the determination of the rate of return.[920] The AER continues to asses the individual WACC parameters and overall cost of capital with regard to these factors, so as to determine the WACC in a manner that will contribute, or be likely to contribute, to the achievement of the national electricity objective.[921]

The AER considers that the material submitted to the WACC review was fully considered as part of that process, and its reasons for adopting the WACC parameters in the SORI are set out in its final decision on the WACC review.[922]

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916 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 255–257.

917 SFG, *Response to aspects of the draft determination: Report prepared for ENERGEX and Ergon Energy*, 2 February 2010. Submitted as appendix 3 to Energex, *Submission on draft determination*, February 2010.

918 This statement is not referenced to a particular WACC review submission. EUAA, *Submission to the AER on QLD DNSPs*, February 2010, p. 6.

919 EUAA, *Submission to the AER on QLD DNSPs*, February 2010, p. 7.

920 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 234, 236, 258, 260–262.

921 NEL, section 16(1).

922 AER, *Final decision, WACC parameters*, May 2009.

International comparisons of the rate of return

The AER notes that the WACC review explicitly considered the form of the CAPM (domestic or international).[923] After evaluation of all submissions, the AER adopted a domestic CAPM framework, with foreign investors recognised to the extent of their presence in the Australian domestic capital market.[924] The AER notes that market observations do not support the conclusion that the Australian capital market is fully integrated with international capital markets.[925] The AER considers that this approach produces estimates commensurate with prevailing market conditions relevant to the benchmark firm consistent with the requirements of the NER,[926] and therefore rejects the EUAA's claim that the rate of return should be determined in an international framework.

The AER observes that the EUAA has relied upon a paper by Mountain and Littlechild which stated that the equity beta set in Australia was above that set for comparable entities in the UK by Ofgem. The AER notes that this paper refers to an asset beta rather than an equity beta.[927] Ofgem's consultant, PricewaterhouseCoopers, estimated the asset beta for UK regulated utilities at between 0.31 and 0.38, with a resulting equity beta range of between 0.7 and 1.1.[928] Ofgem estimated the asset beta at between 0.24 and 0.34, with a resulting equity beta range of between 0.69 and 0.97.[929] Notwithstanding that the AER's equity beta of 0.8 is within these ranges, the AER maintains its position that international evidence is of limited relevance to the estimation of an equity beta for use in a domestic CAPM.[930] Full details of the AER's derivation of the equity beta of 0.8, including consideration of relevant data from Australian equities, are contained in the WACC review.[931]

The AER considers there are several contentious links in the EUAA's argument that the acceptance of Ofgem's proposals by the UK network businesses means the AER's rate of return is too high. First, the argument ignores the cross–country differences already noted by the AER. Second, the UK legislative regime only allows the networks to appeal the entire decision, not a specific component in isolation (as noted

923 AER, *Issues paper, Review of the weighted average cost of capital (WACC) parameters for electricity transmission and distribution, August 2008,* pp. 12–13; AER, *Explanatory statement, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, December 2008, pp. 51–53 and AER, *Final decision, WACC parameters*, May 2009, pp. 97–101.

924 AER, *Final decision, WACC parameters*, May 2009, pp. 100–101.

925 AER, *Explanatory statement, WACC parameters*, December 2008, p. 53 and AER, *Final decision, WACC parameters*, May 2009, p. 100.

926 NER, clauses 6.5.2 and 6.5.4(e).

927 EUAA, *Submission to the AER on QLD DNSPs*, February 2010, p. 6 and B. Mountain and S. Littlechild, *Comparing electricity distribution network costs and revenues in New South Wales and Great Britain*, University of Cambridge Electricity Policy Research Group Working Paper 0930, 18 December 2009, p. 13.

928 PricewaterhouseCoopers, *Final report: Office of Gas and Electricity Markets, Advice on the cost of capital analysis for DPCR5*, 1 December 2009, p. 47 (table 22).

929 Ofgem, *Electricity Distribution Price Control Review, Final Proposals, Allowed Revenues and Financial Issues*, 7 December 2009, p. 14.

930 AER, *Final decision, WACC parameters*, May 2009, pp. 260–264.

931 AER, *Final decision, WACC parameters*, May 2009, pp. 239–344.

by Mountain and Littlechild).[932] As such, no inference can be drawn about the UK regulated networks' acceptance of a particular component of Ofgem's proposal (such as the rate of return).

Relative returns on debt and equity

Although Energex did not dispute the application of the SORI WACC parameters in this instance, it continued to question the reasonableness of the overall estimate of the return on equity arising from the AER's approach and submitted a report from SFG.[933]

All parties—including the AER, the Qld DNSPs, and SFG—consider that conventional finance theory predicts that the return on equity should be higher than the return on debt. In the WACC review, the AER stated:

> …given the residual risk resulting from greater uncertainty of cash flows borne by equity holders, economic reasonableness would imply that the cost of equity would be greater than the cost of debt. Accordingly, to ensure that service providers are provided with a reasonable opportunity to recover efficient costs the regulatory return on equity should be greater than the regulatory cost of debt (at least on average).[934]

The key concern for the Qld DNSPs in their regulatory proposals was that the return on debt should be higher than the return on equity. The AER notes that such concern is unfounded since the return on debt and return on equity generated using the agreed averaging period do not show such a pattern. The expected return on equity calculated from the risk–free rate of 5.64 per cent, an MRP of 6.5 per cent and an equity beta of 0.8, is 10.84 per cent. Table 11.7 shows the return on debt based on the range of credit ratings and data sources examined by SFG in its original report on this matter, updated for the current averaging period.

[932] B. Mountain and S. Littlechild, *Comparing electricity distribution network costs and revenues in New South Wales and Great Britain*, University of Cambridge Electricity Policy Research Group Working Paper 0930, 18 December 2009, pp. 9–10.

[933] The SORI sets out a method to determine the risk–free rate, but a value for the other return on equity parameters (MRP and equity beta), so once the risk–free rate is set the expected return on equity is also estimated. Hence, Energex raises this issue as part of its response on the risk–free rate. Energex, *Submission on draft determination*, February 2010, pp. 14–15 and appendix 3, SFG, *Response to the draft determination*, February 2010.

[934] AER, *Final decision, WACC parameters*, May 2009, p. 42.

Table 11.7: Return on debt with 10–year maturity from CBASpectrum and Bloomberg fair value curves

Data Source		CBASpectrum	Bloomberg
Return on debt with given credit rating (%)	BBB	9.39	10.04 [a]
	BBB+	8.98	na
	A-	8.56	na
	A	8.38	8.80 [a]
	AA	8.05	7.97 [b]
	AAA	7.38	7.35
Return on equity		10.84	

Source: Bloomberg, CBASpectrum, AER analysis.
Notes: Yields are based on average of 40 business days from 1 February 2010 to 26 March 2010. Annualised yields are reported, using the standard AER methodology—that is, based on the DRP from each data provider added to the nominal risk–free rate reported by the RBA.
(a) Extrapolated from seven years to 10 years using the Bloomberg AAA curve.
(b) Extrapolated from five years to 10 years using the Bloomberg AAA curve.

The expected return on equity is higher than the expected return on debt from either data provider as shown in table 11.2. The AER considers that this supports the conclusion that the return on equity is set appropriately using the SORI.

The AER does not rely on the fact that its approach currently produces relative returns in accordance with theory. Equally, Energex's contention does not demonstrate that the SORI methodology is inappropriate. In their regulatory proposals, the Qld DNSPs submitted a report from SFG that showed a period where, if the SORI was applied, the resulting return on equity was below (several different) estimates of the return on debt.[935] The new SFG report submitted by Energex continued to put forward analysis in respect of this period—the 20 business days prior to the 9 April 2009 (the SFG sample period)—as evidence that the SORI values and methods produce a return on equity that is unreasonable and implausible.[936] That is, the Qld DNSPs—and their consultant, SFG—contended that the AER's approach is implausible and unreasonable because it once produced a return on equity below the return on debt. Energex concluded:[937]

> If a business had its WACC reset over the same period in which SFG's analysis was undertaken, it would have locked in an outcome that the AER is now suggesting was a function of abnormal market conditions. The issues the AER has raised with SFG's analysis has merely highlighted the concerns facing regulated businesses, including Energex, that face having a reset occur over such a period, with a WACC outcome locked in for a subsequent 5 year period.

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[935] SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for Energex and Ergon Energy*, 28 May 2009.
[936] SFG, *Response to aspects of the draft determination, Report prepared for Energex and Ergon Energy*, 2 February 2010.
[937] Energex, *Submission on draft determination*, February 2010, p. 15.

The AER evaluates the specific claims about relative returns below, but first notes two broad conceptual issues with this conclusion. The AER considers that the Qld DNSPs—based on the SFG report—invalidly evaluated ex-ante expectations against ex-post outcomes.

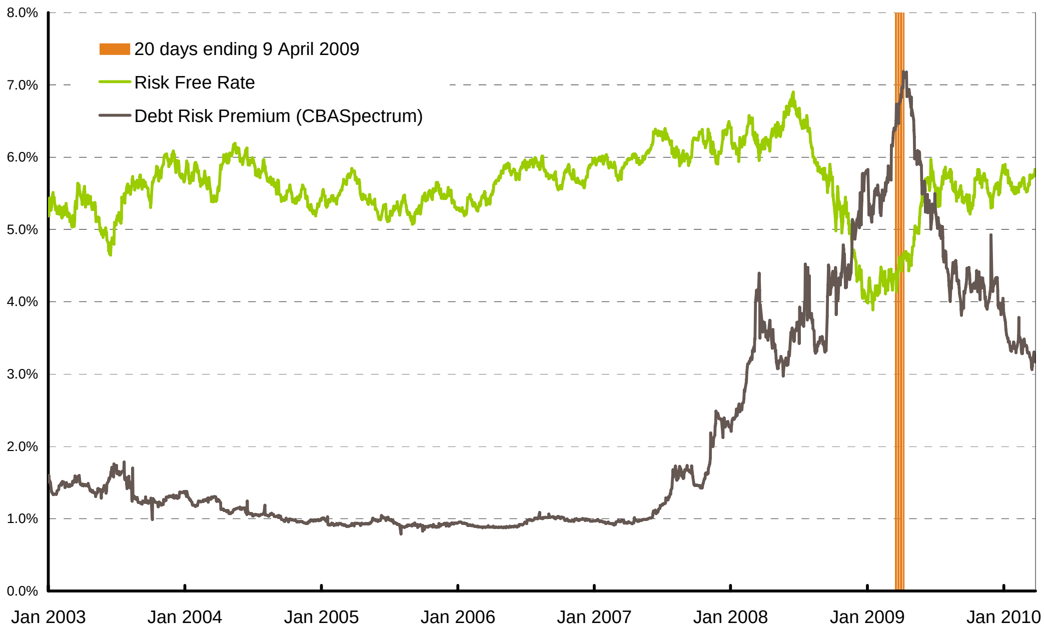
Expectations and outcomes

The AER notes that the CAPM is a model of expectations, not of outcomes. Prior to a given period, the equity investor accepts risk in exchange for an expected rate of return. These expectations are based on all information available to the investor at that time, which (logically) does not include the rate of return outcome for the given period.[938] As such, the return on equity estimated by the CAPM can only be assessed in terms of expectations.

However, the AER notes that SFG has attempted to use rate of return outcomes to assess the validity of rate of return expectations. In other words, SFG asked the question 'were rate of return outcomes in the SFG sample period abnormal'? This question is only indirectly linked to the real issue, which is 'given the market conditions in the SFG sample period, what would be the expected rate of return'?

In retrospect, it is apparent that the SFG sample period combined the top of the estimated debt risk premium (based on CBASpectrum's fair value curve) together with a relatively low risk–free rate (based on observed CGS yields). This is illustrated in figure 11.1.

Figure 11.1: Averaging period selected by SFG compared against the debt risk premium and risk–free rate



Source: CBASpectrum, RBA, AER analysis.

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938 Note that the available information does include past rate of return outcomes, which is why the expected rate of return is often based on the average rate of return outcomes.

After increasing steeply from the middle of 2007 and reaching a peak in around April 2009, the debt risk premium drops steeply after 9 April 2009. The risk–free rate fell quickly around the middle of 2008 reaching a relatively low level around January 2009, before increasing over 160 basis points in the following 6 months (including 9 April 2009). However, on 9 April 2009, an investor is not aware of the rate of return outcome for the 10 April 2009. The investor does not know whether the debt risk premium will decline consistently over the next 12 months, or the future path of the risk-free rate. The AER considers that these rate of return outcomes were not able to influence the expectations set during the SFG sample period.

The AER considers that there were relevant measures of the expected rate of return available during the SFG sample period. The AER notes that both the debt risk premium and the risk–free rate are based on market transactions—that is, data observed from transactions where entities buy and sell financial instruments relevant to the following 10 years (the relevant length of the period under consideration). The entities engaging in these transactions are disclosing their expectations about what will happen during this time. Most importantly, these expectations are not invalidated if at a subsequent point in time outcomes do not match the expectations.

Further, the AER clarifies that it is not asserting that the SFG sample period is abnormal but it does incorporate some of the post-GFC volatility. When the return on equity outcome is highly variable, and debt yields are less volatile it is not unreasonable for debt holders to obtain a higher return outcome than equity holders for a limited period. The AER notes that its WACC review statement on relative returns makes clear that the relationship will hold *only on average*:

> …the regulatory return on equity should be greater than the regulatory cost of debt (at least on average).[939]

Incentive regulation and commitment

As a further issue, the AER notes that the incentive regulatory regime depends on advance commitment. Under the building block framework, the AER sets total revenue based on the total projected efficient costs of the DNSP, where it can gain the benefit or suffer the detriment of any variation from this forecast. As part of this, the return on capital building block is set with reference to a WACC established on benchmark principles—the DNSP gains the benefit or suffers the detriment of any variation of their circumstances from the efficient benchmark.

The averaging period is used to anchor the determination of future expectations consistent with achieving an unbiased estimate . The AER, in accordance with the NER requirements, establishes an agreed averaging period which considers a period proposed by the DNSP. In assessing the proposed period the AER takes account of:

- having the averaging period as close as possible to the date of the final decision, in order to incorporate the most up-to-date information that could best inform rate of return expectations

[939] AER, *Final decision, WACC parameters*, May 2009, p. 42.

- a period that is long enough to avoid contamination from transient fluctuations, which do not reflect useful information that could inform rate of return expectations.

Given this context, there is a strong reason not to allow an ex-post variation of the averaging period after observing 'abnormal' rate of return outcomes. The commitment to the averaging period, in advance, prevents any gaming of the regulatory regime that might otherwise be possible. If the DNSP was allowed the option to vary the averaging period after it had occurred, it would choose to do so only in circumstances where such variation would be likely to increase the rate of return. This would systematically bias the allowed rate of return upwards.

Specific rate of return comparisons

SFG identified four specific comparisons that it considered supported the conclusion that the SORI-derived rate of return on equity is too low.[940] SFG argued that during its selected sample period, the return on debt was higher than:[941]

- the return on levered equity for domestic investors
- the return on unlevered equity for domestic investors
- the return on levered equity for foreign investors
- the return on unlevered equity for foreign investors.

<u>*Return on levered equity for domestic investors*</u>

As background, the draft decision noted:[942]

- If the Bloomberg data service was used to estimate the debt risk premium, the relative returns matched theoretical expectations for the 20 business days to 9 April 2009. That is, the expected return on debt was below the expected levered return on equity for domestic investors.
- If the CBASpectrum data service was used to estimate the debt risk premium across this same period, the relative returns did not match the theoretical expectations. That is, the expected return on debt was above the expected levered return on equity for domestic investors.

The key question is therefore which fair value curve used to estimate the debt risk premium was accurate. The AER notes that it tested the fair yield curves against observed bond yields in the final decision for NSW DNSPs, for a period (2 February

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940 SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for Energex and Ergon Energy*, 28 May 2009, pp. 1–2 and SFG, *Response to aspects of the draft determination, Report prepared for Energex and Ergon Energy*, 2 February 2010, p. 7.

941 SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 7 (table 1) and SFG, *Response to aspects of the draft determination, Report prepared for Energex and Ergon Energy*, 2 February 2010, pp. 7–12.

942 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 244.

to 20 March 2009) that overlaps that selected by SFG.[943] The AER found that the Bloomberg fair value curve was the better predictor of observed bond yields in that period. The AER considers this provides a reasonable basis to conclude that the CBASpectrum cost of debt estimate for the 20 business days to 9 April 2009 was likely to be overstated.[944]

The latest SFG report presents no new information on the merits of CBASpectrum relative to Bloomberg in the SFG sample period. However, it did make a statement about the AER's assessment of the cost of debt in the draft decision. Although SFG included this statement in its section on the return to unlevered equity, the issue is relevant to both levered and unlevered equity. SFG stated:[945]

> *AER's cost of equity is correct and market estimates of the cost of debt are wrong*
>
> 50. The Draft Decision contends that the AER's estimate of the unlevered return on equity is correct and it is actually the debt yield estimates published by CBA Spectrum and Bloomberg that are unreasonable and implausible since they report yields above the AER's estimate of the unlevered return on equity.
>
> 51. This is extraordinary.

The AER notes that SFG appears to have misunderstood the AER's statement, which stated only that the cost of debt estimate from CBASpectrum (not Bloomberg) could be inferred to be implausible.[946] In the SFG sample period, the CBASpectrum and Bloomberg fair value curves differed by more than 270 basis points.[947] The AER considers that it is reasonable and logical to conclude that they cannot both be correct, and that it is 'extraordinary' for SFG to hold the view that two debt estimates which differ so significantly can simultaneously both be accurate.

If the CBASpectrum estimate is incorrect, but the Bloomberg estimate is correct, then the relative returns are consistent with the standard theoretical prediction—that is, the expected return on equity is higher than the expected return on debt.[948]

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943 AER, *Final decision, New South Wales distribution determination*, 28 April 2009, pp. 225–232.

944 Further, the AER notes that SFG referred to its selected 20 days averaging period as being not materially different from the averaging period used in the AER's final decision for the NSW distribution networks. SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 4 (paragraph 14).

945 SFG, *Response to aspects of the draft determination, Report prepared for Energex and Ergon Energy*, 2 February 2010, p. 10.

946 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 244.

947 SFG reported the CBASpectrum return on 10–year BBB+ debt at 11.7 per cent, and the Bloomberg equivalent (using the AER's extrapolation method) at 8.2 per cent for the 20 days to 9 April 2009. This is a difference of 370 basis points. Noting that SFG disputed the AER's extrapolation method, the Bloomberg return on 7–year BBB debt (which requires no extrapolation) was 7.7 per cent, and the CBASpectrum equivalent was 10.4 per cent, a difference of 270 basis points. SFG, *Response to aspects of the Draft Determination, Report prepared for ENERGEX and Ergon Energy*, 2 February 2010, p. 10 and AER analysis.

948 This statement refers to the return on levered equity for domestic investors; the additional scenarios proposed by SFG (unlevered equity, and non-resident investors) are considered below. See AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 240.

The AER considers that this is symptomatic of a more general limitation, in that both Energex and SFG overlook an alternative explanation for the relative returns. SFG repeatedly calculated that the expected return on debt is above the expected return on equity on the basis of the sample period it selected.[949] There are two alternative interpretations of such an observation—either the return on equity is too low, or the return on debt is too high. However, SFG has not considered the latter outcome, and asserted that the return on equity is the incorrectly specified parameter.[950] This view may stem from the terms of reference set by the Qld DNSPs, which SFG reported were:[951]

> Our instructions are to provide an opinion as to whether the regulatory estimate of the cost of equity capital is economically reasonable or plausible.

The presumption that the relative comparison should find fault with the return on equity, rather than the return on debt, then flows through to the Energex submission on the cost of capital.[952]

Considering the hypothetical scenario where the return on debt reported by CBASpectrum during the SFG sample period was correct, and therefore the expected return on equity was below the expected return on debt, the AER notes that the evidence provided by SFG could still be interpreted as supporting a reduction in the return on debt. The AER notes that it currently provides a conservative allowance for the cost of debt. In particular, the term assumption used when setting the debt risk premium overcompensate the benchmark DNSP.

<u>Return on unlevered equity for domestic investors</u>

SFG stated:[953]

> The Draft determination accepts that the parameters in the SORI imply that the required return on unlevered equity in the benchmark DNSP is lower than the required return on debt in the benchmark DNSP.

The AER does not consider that such an implication is correct. SFG's inference appears to be based on the AER statement:[954]

> Although SFG's manipulation may be correct it is merely a theoretical return…

The AER clarifies that the use of 'may' in this sentence was intended as a conditional statement, not acceptance, and notes that the AER clearly stated it had a number of

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949 SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for Energex and Ergon Energy*, 28 May 2009, pp. 14–18 and SFG, *Response to aspects of the draft determination, Report prepared for Energex and Ergon Energy*, 2 February 2010, pp. 7–11.

950 SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 3.

951 SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for Energex and Ergon Energy*, 28 May 2009, p. 1 (paragraph 3).

952 Energex, *Submission on draft determination*, February 2010, p. 14.

953 SFG, *Response to aspects of the draft determination, Report prepared for Energex and Ergon Energy*, 2 February 2010, p. 8 (paragraph 36).

954 AER, *Draft decision, Queensland draft distribution determination*, November 2009 p. 243.

concerns with SFG's finding.[955] The AER considers that the rate of return for unlevered equity calculated by SFG is inappropriate. SFG stated:[956]

> We note that the SFG Report takes the parameter estimates from the SORI and applies the AER's unlevering formula from the SORI to obtain the required return on unlevered equity. This is a mechanical procedure and requires no judgment or subjectivity. There is a unique unlevered equity return implied by, and consistent with, the parameter estimates of the SORI. That is, the SORI effectively sets out what the unlevered return on equity is assumed to be.

The AER notes that this statement makes the following errors:

- The SORI includes no reference to an 'unlevering formula', nor an asset beta such that a particular formula could be inferred.

- There is no 'unique unlevered equity return' because there are a large number of de-levering/re-levering formulae that can be applied. The AER notes that in a previous submission to the AER, SFG stated there were more than a dozen such alternative models.[957] Further, SFG stated:[958]

  > *Re-levering approaches*. The explanatory statement reviews a number of different re-levering procedures. There are different mathematical formulas and different assumptions about debt betas that can be used. There is no question that these different approaches will result in different equity beta estimates.

- The selection of the appropriate formula requires judgement and is not a 'mechanical procedure'.

When the AER considered the estimation of the equity beta in the WACC review it adopted a particular formula for de-levering and re-levering firm specific data to be comparable to the benchmark.[959] The AER maintains its position that this is appropriate, and that the use of this formula enabled reliable estimation of a value for the equity beta.

However, this has been interpreted by SFG as a statement that the AER endorses the use of this formula for all circumstances and purposes. This is not the case. The AER set out why this formula was appropriate in the particular circumstances relevant to

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955 For example, 'The AER considers SFG has not demonstrated that the unlevered return on equity based upon the SORI parameters is unreasonable and implausible'. See AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 243, 244.

956 SFG, *Response to aspects of the Draft Determination, Report prepared for ENERGEX and Ergon Energy*, 2 February 2010, p. 8 (paragraph 38).

957 SFG, *The reliability of empirical beta estimates, Report prepared for ENA, APIA, and Grid Australia*, 15 September 2008, p. 27.

958 SFG, *The reliability of empirical beta estimates: Response to AER proposed revision of WACC parameters, Report prepared for ENA, APIA and Grid Australia*, 1 February 2009, pp. 22–23. See also page 19 of this reference for a similar statement.

959 Specifically, the Brealey and Myers formula with a debt beta of zero. AER, *Explanatory statement, WACC parameters*, December 2008, p. 202.

the WACC review, explicitly describing limitations on its use. First, the AER stated:[960]

> The AER notes that it is generally accepted that the choice of de-levering and re-levering formula, in general, does not make a significant difference to the resultant estimates, so long as the same formula is adopted for both de-levering and re-levering.

SFG did not use the formula to de-lever and then re-lever the equity beta, but rather ‘unlevers’ the equity beta to consider a firm with no debt at all. Using a formula to de-lever and then re-lever means that certain limitations inherent to the formula may cancel out. Using the same formula in only one direction is likely to introduce systematic bias.

As an extension of this concern, the AER noted in the WACC review that the formula was appropriate because the companies were already geared at levels close to the benchmark:[961]

> The AER's position from the explanatory statement, which it maintains, is that the use of this formula (set out in section 8.5.3.2) is a perfectly reasonable approach to de-lever and re-lever the beta estimates of energy stocks, particularly as the actual gearing of these comparator businesses and the assumed benchmark level of gearing are not significantly different to each other.

That is, the formula was appropriate because the nine companies included in the equity beta analysis had gearing levels ranging from 30 per cent to 76 per cent, with an average gearing of 54 per cent.[962] The de-levering and re-levering to the benchmark gearing of 60 per cent did not involve a large change in the characteristics of the data set. In particular, some firms have their gearing reduced (for example, from 76 per cent to 60 per cent) but others have their gearing increased (for example, from 30 per cent to 60 per cent) such that certain limitations inherent to the formula may cancel out.

SFG, however, is adjusting from a gearing of 60 per cent to a gearing of 0 per cent. This is a large alteration in one direction, and the AER does not consider it valid to apply the formula in this case.

Finally, the AER also noted in the WACC review:[963]

> However, this linear relationship between financial leverage and the equity beta may not hold if the debt beta does not equal zero or if there are market imperfections.

That is, the formula was appropriate because across the eight years of analysis, the average debt beta should be sufficiently close to zero that it could reasonably be set to zero.

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960 AER, *Final decision, WACC review*, 1 May 2009, p. 265.
961 AER, *Final decision, WACC review*, 1 May 2009, p. 253.
962 Henry, *Estimating β*, 23 April 2009, p. 10.
963 AER, Final decision, WACC parameters, 1 May 2009, p. 253.

SFG chose a 20 day period at the height of the GFC for its analysis. In the draft decision, the AER noted that the default risk on debt would be much higher than normal in that specific period.[964] Under these circumstances, it is not reasonable to set the debt beta to zero, which further supports the AER's conclusion that it is invalid to apply the formula in such a manner.

The AER considers, consistent with its position in the WACC review, that the Brearley and Myers de-levering/re-levering formula with a debt beta set at zero—will not hold under extreme scenarios such as those proposed by SFG.[965] This in no way invalidates the use of this formula, under appropriate circumstances, to determine the equity beta value as set in the SORI.

The AER therefore considers that there is no reasonable basis to consider the unlevered return on equity relative to the return on debt.

Return on levered and unlevered equity for foreign investors

SFG noted an additional issue regarding the relative rate of return on equity for overseas investors. Since the majority of foreign investors are unable to derive a benefit from imputation credits,[966] and the non-resident investor pays the capitalised cost of future imputation credits at share purchase,[967] the expected return on equity for these international shareholders is lower than that for Australian domestic shareholders.[968] SFG calculated—based on the 20 days averaging period ending 9 April 2009—that the return on equity for these foreigners was substantially below the return on AAA rated corporate debt and suggested this to be unreasonable, implausible and illogical.[969]

The AER considers that, at its core, this argument is about the value of gamma. The two groups of investors—domestic and foreign—have different rates of return if the market value of a franking credit is higher than zero. The AER notes that even though SFG had previously made isolated comments supporting a gamma of zero,[970] both the Qld DNSPs proposed a positive value for gamma. The AER considers all the issues associated with gamma in chapter 9.

964 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 241.

965 The specific extreme scenario considered in the WACC review is a proposal by the JIA to de-lever and re-lever the entire market. AER, *Final decision, WACC review*, 1 May 2009, pp. 253–254.

966 SFG, *Response to the draft determination*, February 2010, pp. 10–11 (paragraphs 53–56).

967 SFG, *Response to the draft determination*, February 2010, pp. 11–12 (paragraphs 57–62).

968 SFG, *Response to the draft determination*, February 2010, pp. 10 (paragraph 52), 12 (paragraph 66); and SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for ENERGEX and Ergon Energy*, 28 May 2009, p. 15 (paragraphs 64).

969 SFG, *The reasonableness of regulatory estimates of the cost of equity capital, Report prepared for ENERGEX and Ergon Energy*, 28 May 2009, p. 14 (paragraphs 63).

970 SFG, *The impact of franking credits on the capital of Australian firms, Report prepared for ENA, APIA and Grid Australia*, 16 September 2008, p. 30 (paragraph 112.e); SFG, *Market practice in relation to franking credits and WACC: Response to AER proposed revision of WACC parameters, Report prepared for ENA, APIA and Grid Australia*, 1 February 2009, p. 3 (paragraph 8); and SFG, *Gamma: Further evidence to support departure from the AER's statement of regulatory intent, Report prepared for Energex and Ergon*, 7 December 2009, p. 44 (paragraphs 209-210).

Summary

For the above reasons, the AER considers that the rate of return determined in accordance with clause 6.5.2 of the NER and the SORI has been set at a level sufficient to provide for efficient investment in electricity network infrastructure. The AER considers that the approach taken in the WACC review and subsequently in this decision will contribute, or is likely to contribute, to the achievement of the national electricity objective.

11.5 AER conclusion

The AER determines a nominal vanilla WACC of 9.72 per cent for the Qld DNSPs as set out in table 11.8. The WACC is based on the updated risk–free rate and DRP, based on the agreed averaging period set out above. The inflation forecast has been updated based on the latest available RBA forecasts and targets. The other WACC parameters are based on the SORI, as there was no persuasive evidence justifying a departure.

Table 11.8: AER conclusion on WACC parameters

Parameter	Energex	Ergon Energy
Nominal risk–free rate	5.64%	5.64%
Real risk–free rate	3.04%	3.04%
Expected inflation rate	2.52%	2.52%
Gearing level (Debt:Equity)	60:40	60:40
Market risk premium	6.5%	6.5%
Equity beta	0.8	0.8
Debt risk premium	3.33%	3.33%
Nominal pre-tax return on debt	8.98%	8.98%
Nominal post-tax return on equity	10.84%	10.84%
Nominal vanilla WACC	9.72%	9.72%

11.6 AER decision

In accordance with clause 6.12.1(5) of the NER, the rate of return to apply to Energex is 9.72 per cent.

In accordance with clause 6.12.1(5) of the NER, the rate of return to apply to Ergon Energy is 9.72 per cent.

12 Service target performance incentive scheme

This chapter discusses the AER's application of the service target performance incentive scheme (STPIS) to the Qld DNSPs in the next regulatory control period.[971]

The STPIS establishes service performance targets based on historical levels of performance, and provides incentives to DNSPs in the form of financial rewards for meeting targets and financial penalties for a failure to meet targets. The STPIS provides incentives for DNSPs to maintain and improve service performance. The regulatory framework provides DNSPs with an incentive to reduce costs where practical. In a situation where service performance is maintained or improved, cost reductions are beneficial to both DNSPs and their customers. However, cost efficiencies achieved at the expense of service levels experienced by customers are not desirable.

The STPIS has two broad components, the s–factor and the Guaranteed Service Levels (GSL) scheme. The s–factor is comprised of three components, namely reliability of supply, quality of supply and customer service.

12.1 AER draft decision

Energex

The AER determined that the national distribution STPIS will apply to Energex in the next regulatory control period in the following form:[972]

- the reliability of supply component parameters: system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI), will apply to Energex's CBD, urban and short rural network segments

- overall revenue at risk of ±2 per cent

- the incentive rates for each parameter are to be determined in accordance with clause 3.2.2 and appendix B of version 01.2 of the STPIS

- the performance targets for each parameter in each regulatory year of the next regulatory control period as set out at table 12.6 of the draft decision

[971] The AER published its national distribution STPIS on 26 June 2008 (Version 01.0). On 8 May 2009, the AER published an amended STPIS (Version 01.1) to address issues regarding the interaction between the cap on revenue at risk and the equation for the calculation of the s–factor, and to clarify the operation of the scheme. On 25 November 2009 the AER published a further amended STPIS (Version 01.2) which addressed amongst other things how the Major Event Day (MED) boundary is calculated. See AER, *Final decision, Electricity distribution network service providers, Service target performance incentive scheme*, November 2009, appendix C.

[972] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 306.

- the GSL component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn the AER's GSL scheme will take effect from the day the jurisdictional scheme is withdrawn.

Ergon Energy

The AER determined that the national distribution STPIS will apply to Ergon Energy in the next regulatory control period in the following form:[973]

- the reliability of supply component parameters, SAIDI and SAIFI, will apply to Ergon Energy's urban, short–rural and long–rural network segments. The customer service component telephone answering parameter will also apply

- overall revenue at risk of ±2 per cent, inclusive of a ±0.2 per cent for the telephone answering parameter

- the incentive rates for each parameter is to be determined in accordance with clauses 3.2.2 and 5.3.2, and appendix B of version 01.2 of the STPIS

- the performance targets for each parameter in each regulatory year of the next regulatory control period as set out at table 12.7 of the draft decision

- the GSL component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn, the AER's GSL scheme will take effect from the day the jurisdictional scheme is withdrawn.

12.2 Revised regulatory proposals

Energex

Energex did not address the application of the STPIS set out in the draft decision.

Ergon Energy

Ergon Energy did not accept the performance targets established for its reliability of supply parameters. It submitted updated performance targets that incorporated 2008–09 data and stated these performance targets should apply.[974]

Ergon Energy accepted the telephone answering parameter performance target on the basis that it can exclude major event days (MED) from its performance.[975]

Ergon Energy submitted that the natural logarithm of its historical SAIDI data from 2003–04 to 2007–08 resulted in a normally distributed data set.[976]

Ergon Energy stated that it does not have the capacity to measure momentary interruptions and therefore cannot report them as required in appendix Q of the draft decision.[977]

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[973] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 306.
[974] Ergon Energy, *Revised Regulatory Proposal*, January 2010, pp. 189–190.
[975] Ergon Energy, *Revised Regulatory Proposal*, January 2010, p. 190.
[976] Ergon Energy, *Revised Regulatory Proposal*, January 2010, pp. 191–192.

12.3 Submissions

Energex submitted that reporting requirements should only be imposed on it to the extent they are reasonably necessary for the AER to carry out its regulatory functions and do not impose an undue compliance burden. Energex also did not consider that the AER's conclusion on the parameters that it should report on was clear in the draft decision.[978]

12.4 Issues and AER considerations

12.4.1 Performance targets

Revised regulatory proposal

Ergon Energy did not accept the draft decision to set performance targets for the STPIS at the minimum service standard – 10 (MSS–10) per cent.

In response to the draft decision, Ergon Energy stated that:[979]

- neither the MSS targets nor the MSS–10 per cent business targets were used to develop its capex and opex programs.
- its proposed approach to setting targets was consistent with the approach set out in clause 2.5.3 of the AER's framework and approach paper.
- for each feeder type, the MSS targets for each year of the next regulatory control period are more onerous than Ergon Energy's average historical unplanned reliability performance.
- these MSS targets should apply rather than the AER's MSS–10 per cent.

Ergon Energy noted that the MSS includes both planned and unplanned outage performance, whereas the STPIS only assesses unplanned outage performance. Conversely, the STPIS targets should also include 'service fuse and beyond outages' which are not included in the MSS. Therefore, Ergon Energy's proposed targets for the STPIS have been 'adjusted' from the MSS targets to remove planned outage data and include service fuse and beyond outages.[980]

These adjusted performance targets also incorporate 2008–09 data that was not available for the AER to assess or consult on at the time it made the draft decision.[981]

Ergon Energy also notified the AER on 26 February 2010 that it failed to remove two MEDs from its 2008–09 data.[982]

Ergon Energy's updated proposed performance targets are set out in table 12.1.

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977 Ergon Energy, *Revised Regulatory Proposal*, January 2010, pp. 192–193.
978 Energex, *Submission on draft determination*, February 2010, p. 30.
979 Ergon Energy, *Revised Regulatory Proposal*, January 2010, pp. 189–190.
980 Ergon Energy, *Revised Regulatory Proposal*, January 2010, Attachment RP 899C, p. 1.
981 Ergon Energy, *Revised Regulatory Proposal*, January 2010, pp. 189–190.
982 Ergon Energy, email 26 February 2010.

Table 12.1: Ergon Energy's proposed performance targets, 2010–15

		Targets				
Parameter	**Unit**	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
SAIDI						
Urban	Minutes	137.27	136.35	135.42	134.50	133.58
Short rural	Minutes	318.41	313.90	309.40	304.89	300.39
Long rural	Minutes	755.17	742.63	730.10	717.57	705.03
SAIFI						
Urban	per 0.01 interruptions	1.84	1.82	1.80	1.78	1.76
Short rural	per 0.01 interruptions	3.32	3.28	3.24	3.20	3.16
Long rural	per 0.01 interruptions	6.08	6.00	5.92	5.83	5.75
Customer service						
Telephone answering	percentage	77.3	77.3	77.3	77.3	77.3

Source: Ergon Energy, response to information request PB.ERG.RRP 0.1 to 0.5, 26 February 2010.

Consultant review

PB stated that Ergon Energy does not appear to have reconciled its proposed expenditure with its mandated reliability performance and for this reason was unable to verify whether the increased expenditures associated with the changed maintenance and planning practices and for reliability improvement are sufficient to achieve the MSS targets. However, PB reiterated its previous conclusion that the unplanned reliability performance should improve significantly under the expenditures proposed by Ergon Energy.[983]

PB was also of the view that several adjustments needed to be made to the MSS targets given the basis for the MSS targets and the STPIS targets differ, respectively representing the minimum and the 'on average' service performance required.[984] Accordingly, PB advised that in addition to adjusting the MSS targets to remove planned outages and service fuse and beyond outages, the MSS targets should be adjusted to address these different bases.[985] Such an adjustment is necessary to avoid Ergon Energy receiving revenue through the STPIS for performance mandated by the *Electricity Industry Code*.[986]

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983 PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
984 PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
985 PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
986 PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.

PB previously considered that the internal targets of MSS–10 per cent should be used to inform the setting of targets for the STPIS as they are likely to represent future performance. PB analysed Ergon Energy's historical performance to determine the statistical variation about the average service performance, and concluded that its analysis supported the use of MSS–10 per cent.[987]

AER considerations

The AER notes Ergon Energy's submission that neither the MSS targets nor the MSS–10 per cent targets were used to develop its capex and opex programs but accepts PB's advice, as noted above, that:

- Ergon Energy does not appear to have reconciled forecast expenditure with reliability performance and for this reason PB was unable to verify whether the increased expenditures associated with the changed maintenance and planning practices and the expenditure for reliability improvement are sufficient to achieve the MSS targets[988]
- the expenditures proposed by Ergon Energy will significantly improve unplanned reliability.[989]

The AER also recognises that the MSS are levels of reliability performance which are required to be met every year by Ergon Energy under the *Electricity Industry Code*.[990]

In response to Ergon Energy's submission that its approach to setting performance targets was consistent with the framework and approach paper, the AER recognises that the framework and approach paper stated that the STPIS targets would be set 'equal to' the MSS targets.[991]

The AER notes that the framework and approach paper only sets out the AER's likely approach which is neither binding on the AER or Ergon Energy, as provided for in clause 6.8.1(h) of the NER.

The AER has reviewed this reference to setting STPIS targets 'equal to' MSS targets and recognises that reading this reference literally is clearly unworkable. This is itself evidenced by Ergon Energy's proposal that it would nevertheless need to adjust the MSS targets to remove planned outage data in setting its proposed targets.

The AER considers its approach is consistent with the purpose of the framework and approach. However, if the AER's approach amounts to a departure from that approach, the AER considers that set out in the discussion below are robust reasons for a departure from the framework and approach paper in this instance.

The AER's underlying position in the framework and approach paper was not that there was to be strict equality between the STPIS targets and the MSS targets, but

987 PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, pp. 94–96.
988 PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
989 PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
990 Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP 899C, p. 1.
991 AER, *Final framework and approach paper: Application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 14.

rather that the latter would guide the setting of the former, such that the level of service performance required between the two would be similar. That is, the DNSP would be required to achieve the same level of service performance to meet the STPIS targets as it would take to satisfy the MSS targets. To these ends the AER stated in the framework and approach paper that the MSS targets would underpin the STPIS targets recognising methodological differences between the measurement of service performance under the STPIS and the MSS.[992]

The rationale for the MSS targets underpinning the STPIS targets was in part a response to a concern, raised during the consultation process for the framework and approach paper. The concern was that given the Qld DNSPs had indicated that they would likely propose capex and opex allowances to achieve the MSS targets, there was the possibility they may be rewarded for achieving higher performance standards even though the improved level of service was funded via the capex and opex allowances, if performance targets were set on the basis of average historical data.[993]

A further consideration is that the STPIS provides DNSPs with the incentive to maintain average service performance across feeders in line with the STPIS performance targets or to improve upon the targets. The MSS targets, on the other hand, stipulate the minimum service performance. As noted by PB:

> In PB's view, a further adjustment is required before the STPIS targets can be set equal to the MSS targets. This adjustment is required to account for the different basis of the targets: that is, the MSS targets being 'at the minimum' and the STPIS targets being 'on average'[994]

The AER recognises that fluctuations in performance of feeders are likely to occur from one year to another, due to factors which are beyond the control of the DNSP (for example, due to weather). For this reason the AER considers that a prudent DNSP, subject to the MSS, will not aim for its average service performance to meet the MSS targets. Rather, a prudent DNSP will aim to exceed the MSS targets such that in the years where the performance of some feeders falls due to normal fluctuations it will still meet or exceed the minimum targets imposed by the MSS.

For this reason, PB recommended that to be consistent with the framework and approach paper the MSS targets need to be adjusted to account for the different bases of the targets.[995] The AER agrees with PB that it will need to adjust the MSS targets to produce STPIS targets that correspond to a similar level of service performance as the MSS targets.

The AER requested Ergon Energy to provide adjusted MSS targets taking into account the different bases.[996] In its response, Ergon Energy did not provide any

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992 AER, *Final framework and approach paper: Application of schemes – Energex and Ergon Energy 2010–15*, November 2008, pp. 13–14.
993 AER, *Final framework and approach paper: Application of schemes*, November 2008, p. 13.
994 PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
995 PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
996 AER, information request PB.ERG.RRP 0.1 to 0.5, 9 February 2010.

alternative targets or a methodology for setting targets which allowed for the different basis of the targets.[997]

PB previously relied on Ergon Energy's internal targets for the purpose of setting the STPIS targets at MSS–10 per cent.[998] In the absence of alternative targets or a methodology from Ergon Energy, PB applied the following methodology:[999]

- normalise the annual reliability data by using the natural log function (this allows a normal distribution to be applied)
- assume that the minimum standard should be exceeded on average no more often than 1 in 5 years (the length of the regulatory control period): the number of standard deviations that must be achieved is 0.78
- determine the quantity (minutes for SAIDI and interruptions for SAIFI) corresponding to the mean plus 0.78 standard deviations, being the upper bound of performance that could be expected to be exceeded on average no more often than 1 in 5 years
- convert the upper bound (normalised) to the base by calculating the exponential
- calculate the percentage change between the upper bound and average performance.

The calculation is shown in table 12.2.

PB concluded that its analysis indicated that the on average STPIS targets should be set approximately 12 to 19 per cent below the MSS targets to meet the MSS targets with a probability of not achieving the MSS targets of 1 in 5 years (note that a lower target indicates better service performance).[1000] PB noted that the outcome of this statistical analysis was broadly consistent with its previous approach of using internal targets (although it supported the use of more onerous targets than MSS–10 per cent).[1001] Accordingly, PB maintained that the use of MSS–10 per cent, while conservative, was an appropriate adjustment to the MSS targets for the purposes of setting the STPIS targets.

[997] Ergon Energy, response to information request PB.ERG.RRP 0.1 to 0.5, 26 February 2010.
[998] PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 95
[999] PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 94
[1000] PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 94.
[1001] PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 95.

Table 12.2: PB's percentage change calculation

Item	Urban	Short rural	Long rural
SAIFI			
Mean of data	2.15	4.17	7.02
Normalised data:			
Mean of 03/04–08/09	0.75	1.41	1.93
0.78 standard deviation	0.15	0.16	0.17
Upper bound (mean less 0.78 standard deviation)	0.60	1.26	1.76
Equivalent SAIFI upper bound	1.82	3.52	5.83
% change mean to upper bound	15%	16%	17%
SAIDI			
Mean of data 03/04–08/09	193.9	415.5	904.9
Normalised data			
Mean of 03/04–08/09	5.2	6.0	6.8
0.78 standard deviation	0.18	0.13	0.12
Upper bound (mean less 0.78 standard deviation)	5.06	5.89	6.68
Equivalent SAIDI upper bound	158.0	360.2	793.3
% change mean to upper bound	19%	13%	12%

Source: PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 95.

The AER reviewed PB's work and considers it to be a robust statistical approach which relies on Ergon Energy's historical data to determine the likely variance of the minimum service performance from the average service performance. The AER therefore accepts PB's analysis which supported setting targets at MSS–10 per cent.

Ergon Energy provided targets which were based on the 2008–09 data and subsequently advised the AER that it had identified two additional events in its historical data that met the criteria for exclusion. The AER notes that the data from 2008–09 was not available when Ergon Energy submitted its regulatory proposal. PB reviewed the 2008–09 data and stated that Ergon Energy's adjustments were consistent with the removal of two days where SAIDI exceeded the threshold. Further, PB was satisfied that Ergon Energy correctly applied the removal of planned interruptions, the addition of service fuse and beyond interruptions and the 5 year average performance.

AER conclusion

The AER considers that Ergon Energy's proposed STPIS targets are not appropriate for the reasons set out below:

- Ergon Energy is required to meet the MSS targets under the *Electricity Industry Code*[1002]

- there are methodological differences in measuring service performance between the MSS and the STPIS, that is, the MSS targets are minimum requirements, whereas the STPIS targets measure average performance[1003]

- PB advised that to allow for the different bases in setting targets, the MSS targets will need to be adjusted to be used for the STPIS targets.[1004] After the adjustment, the level of service performance required to meet the STPIS targets will be similar to the level of service performance required to satisfy the MSS targets

- the AER maintains that it is appropriate to set targets in a manner which will not financially reward Ergon Energy under the STPIS for improved service performance where the improvements to service performance have been funded through capex and opex allowances and are required under the *Electricity Industry Code*.[1005] The AER noted:

  - Ergon Energy's inability to reconcile expenditure with its level of service performance is not a reason to set Ergon Energy's performance targets at a level less onerous than the MSS[1006]

  - the expenditures proposed by Ergon Energy will significantly improve unplanned reliability.[1007]

Accordingly, the AER will apply the updated performance targets to Ergon Energy set out at table 12.3.

[1002] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP 899C, p. 1.
[1003] PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
[1004] PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
[1005] STPIS, clause 3.2.1(a)(1); see also PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
[1006] PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.
[1007] PB, *Review of Ergon Energy's revised regulatory proposal*, March 2010, p. 92.

Table 12.3: AER performance targets for Ergon Energy, 2010–15

		Targets				
Parameter	**Unit**	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
SAIDI						
Urban	minutes	129	128	127	127	126
Short rural	minutes	296	291	287	283	279
Long rural	minutes	699	687	675	664	652
SAIFI						
Urban	per 0.01 interruptions	1.69	1.68	1.66	1.64	1.63
Short rural	per 0.01 interruptions	3.06	3.02	2.98	2.94	2.91
Long rural	per 0.01 interruptions	5.59	5.52	5.44	5.37	5.29
Customer service						
Telephone answering	percentage	77.3	77.3	77.3	77.3	77.3

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 304.

12.4.2 Incentive rates

The incentive rates which the AER set out in the draft decision were based on the average demand forecasts set out at Table 121 of Ergon Energy's regulatory proposal. However, after it published the draft decision, the AER identified an error in the average column of Ergon Energy's Table 121 which resulted in an error in the incentive rates which the AER applied in the draft decision. The AER also notes that both of the Qld DNSPs' revenues have changed in the final decision from the draft decision.

Therefore the incentive rates for the Qld DNSPs have been updated to correct the error identified and reflect the changes to the Qld DNSPs' revenues. The updated incentive rates are set out at table 12.5 and table 12.6.

12.4.3 Telephone answering parameter

Ergon Energy accepted the telephone answering parameter's performance target on the basis that it can exclude MEDs from its performance.[1008]

PB advised that Ergon Energy's proposed approach is consistent with clause 5.4 of the STPIS, which allows MEDs to be excluded.

[1008] Ergon Energy, *Revised Regulatory Proposal*, January 2010, p. 190.

The AER therefore concludes that it is appropriate that MEDs be excluded from Ergon Energy's performance.

12.4.4 Other issues

Reporting requirements

The AER is implementing its STPIS for the first time in Queensland and South Australia. Reliable data is critical for the AER to be able to implement its STPIS to produce robust results. That said, the AER recognises it is currently precluded from implementing some components and parameters of the STPIS due to a lack of data. The AER does not take lightly the obligations that it imposes on DNSPs with respect to complying with reporting requirements. The AER is satisfied that the reporting requirements which it imposes are necessary to maintain and improve service standards consistent with the objectives of the STPIS.

The AER stated at clause 3.1(d) of the STPIS, that where the DNSP demonstrates to the AER it is unable to measure momentary average interruption frequency index (MAIFI), a DNSP may propose a variation to exclude reporting MAIFI for a regulatory control period or a portion of a regulatory control period.

Ergon Energy demonstrated that it does not have the capacity to measure and report MAIFI as set out at appendix Q of the draft decision and appendix A of the STPIS.[1009] Therefore, the AER accepts Ergon Energy's proposal to exclude itself from reporting MAIFI for the next regulatory control period.

Alternative telephone answering parameter

Energex submitted that even though the telephone answering parameter will not apply to it for the next regulatory control period it will have to report the telephone answering parameter. Energex noted that it proposed to use average speed of answer (ASA), whereas in the draft decision the AER noted PB's advice which recommended the use of grade of service (GOS) as set out in the STPIS. Energex did not consider that the AER's conclusion on which parameter it should report on was clear in the draft decision.[1010]

In the draft decision, the AER decided not to apply the telephone answering parameter to Energex. Energex noted that it is still required to report on this parameter even though there will be no financial incentive attached to it. The AER reiterates its position in the draft decision that any amendment to the telephone answering parameter must be consistent with the objectives of the STPIS.[1011] PB advised the AER that the GOS measure is generally more consistent with the objectives of the STPIS.[1012] The AER requires that Energex report the GOS telephone answering parameter.

[1009] Ergon Energy, *Revised Regulatory Proposal*, January 2010, p. 192.
[1010] Energex, *submission*, February 2010, p. 30.
[1011] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 300.
[1012] PB, *Report for the AER's draft decision – Energex*, October 2009, pp. 134–137.

12.5 AER conclusion

The AER confirms its draft decision to apply the STPIS to the Qld DNSPs.

For the reasons discussed in section 12.4 the AER has rejected the performance targets proposed by Ergon Energy and will maintain the targets as set out in the draft decision. The AER will apply the performance targets which are set out at table 12.3. The performance targets applying to Energex reflect those set out in the draft decision and for completeness are set out at table 12.4.

Table 12.4: AER performance targets for Energex, 2010–15

		Targets				
Parameter	**Unit**	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
SAIDI						
CBD	minutes	3.3	3.3	3.3	3.3	3.3
Urban	minutes	69.4	67.7	66.0	64.3	63.0
Short rural	minutes	173.2	164.4	158.0	152.4	147.6
SAIFI						
CBD	per 0.01 interruptions	0.032	0.032	0.032	0.032	0.032
Urban	per 0.01 interruptions	1.044	1.032	1.020	1.008	0.996
Short rural	per 0.01 interruptions	2.285	2.201	2.120	2.041	1.967

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 303.

The AER will update the incentive rates to apply to the Qld DNSPs to allow for the amended revenues to apply to the Qld DNSPs. The AER will apply the incentive rates which are set out at table 12.5 and table 12.6.

Table 12.5: AER incentive rates for Energex 2010–15

Parameter	Incentive rate
Reliability of supply component	
SAIDI	
CBD	0.0088
Urban	0.0634
Short-rural	0.0134
SAIFI	
CBD	0.7993
Urban	4.2346
Short-rural	1.0957

Source: AER analysis

Table 12.6: AER incentive rates for Ergon Energy 2010–15

Parameter	Incentive rate
Reliability of supply component	
SAIDI	
Urban	0.0218
Short-rural	0.0189
Long-rural	0.0043
SAIFI	
Urban	1.7251
Short-rural	1.9741
Long-rural	0.5755
Customer service component	
Telephone answering parameter	–0.0400

Source: AER analysis

12.6 AER decision

In accordance with clause 6.12.1(9) of the NER, the AER has determined that the national distribution STPIS will apply to Energex in the next regulatory control period in the following form:

1. the applicable component and parameters are the SAIDI and SAIFI reliability of supply parameters. The AER will not apply the telephone answering customer service parameter to Energex
2. overall revenue at risk is ±2 per cent
3. the incentive rates to apply to each applicable parameter were calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of version 01.2 of the STPIS, as set out in table 12.5 of this decision
4. that the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period are as set out in table 12.4 of this decision
5. the GSL component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn the AER will implement such a scheme from the day the jurisdictional scheme is withdrawn.

In accordance with clause 6.12.1(9) of the NER, the AER has determined that the national distribution STPIS will apply to Ergon Energy in the next regulatory control period in the following form:

1. the applicable component and parameters are the SAIDI and SAIFI reliability of supply parameters. The AER will apply the telephone answering customer service parameter to Ergon Energy
2. overall revenue at risk is ±2 per cent and ±0.2 per cent for the telephone answering parameter
3. the incentive rates to apply to each applicable parameter were calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of version 01.2 of the STPIS, as set out in table 12.6 of this decision
4. that the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period are set out in table 12.3 of this decision
5. the GSL component will not apply while the QCA's GSL scheme remains in place. In the event that the QCA's GSL scheme is withdrawn the AER will implement such a scheme from the day the jurisdictional scheme is withdrawn.

In accordance with clause 6.3.2(a)(3) of the NER, the STPIS to apply to the Qld DNSPs is as specified in section 12.5 of this decision.

13 Efficiency benefit sharing scheme

This chapter sets out how the AER intends to apply its efficiency benefit sharing scheme (EBSS) to the Qld DNSPs. The EBSS shares between DNSPs and distribution network users the efficiency gains or losses derived from the difference between a DNSP's actual opex and the forecast opex allowance for a regulatory control period.

In its framework and approach, the AER decided that its likely approach for the Qld DNSPs' distribution determinations would be to apply the national EBSS during the next regulatory control period.[1013] However, the scheme will not have a direct financial impact until the regulatory control period commencing 1 July 2015 when the Qld DNSPs will receive carryover benefits/penalties for efficiency gains or losses made during the next regulatory control period.

13.1 AER draft decision

The AER stated it would apply the EBSS, released in June 2008, to the Qld DNSPs for the next regulatory control period. The AER stated it would not adjust the EBSS for the consequences of changes in demand growth for the Qld DNSPs in the next regulatory control period.

The AER considered the following opex cost categories should be excluded from the operation of the EBSS for the next regulatory control period for the Qld DNSPs:

- debt raising costs
- insurance and self insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives, including the demand management innovation allowance.

These are in addition to the costs of pass through events which are excluded by the EBSS. Benchmark efficient equity raising costs have been amortised and therefore are not included as an opex category.

No submissions were received on this issue.

13.2 Revised regulatory proposals

Energex proposed that superannuation costs be removed from the list of excluded opex cost categories for the operation of the EBSS.[1014] The AER's draft decision excluded superannuation costs from the operation of the EBSS for the Qld DNSPs. On 2 March 2010, however, Energex notified the AER that while it believes that including superannuation costs in the operation of the EBSS is less administratively burdensome, Energex understands that the AER has a preference to have

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1013 AER, *Final framework and approach paper: Application of schemes*, November 2008.
1014 Energex, *Revised regulatory proposal*, January 2010, p. 46.

superannuation costs excluded from the EBSS, consistent with the AER's decision for all other DNSPs, and Energex accepts the AER's position to have superannuation costs excluded from the EBSS.[1015]

Energex submitted that uncontrollable opex that meets the relevant criteria under clause 6.6.1(j) of the NER but fails the AER's general nominated pass through event materiality threshold should be excluded from the operation of the EBSS. Energex argued that the intention of the EBSS is to achieve efficiency over the costs that a DNSP can control and that the EBSS contains a provision that requires a DNSP to nominate the exclusion of uncontrollable costs. Energex noted that the AER's decision to adopt a pass through event threshold of one per cent of smoothed revenue allowance translates to a minimum $12 million hurdle for events to be approved under general nominated pass through arrangements. Energex also noted that the AER's draft decision for ETSA Utilities provided for the exclusion from the EBSS uncontrollable expenditure that meets the relevant criteria under clause 6.6.1(j) of the NER but fails the pass through materiality threshold.[1016]

[redacted][1017]

Energex stated that the opex costs associated with [redacted] should be excluded from the EBSS.[1018]

Ergon Energy did not propose any further adjustments to the operation of the EBSS other than those specified in the draft decision or required by the AER as set out in section 2.3.2 of the EBSS.[1019] Ergon Energy proposed that consistent with requirements for ring–fencing compliance and regulatory reporting statements, the reporting deadline for the EBSS be 31 October of each year.[1020]

Ergon Energy also proposed [redacted] be excluded from the actual opex amounts used to calculate carryover gains or losses under the EBSS, given that the costs will be incremental to any opex allowances previously proposed or approved by the AER.[1021]

1015 Energex, email response to AER, 2 March, 2010, confidential.
1016 Energex, *Revised regulatory proposal*, January 2010, p. 45.
1017 Energex, *Revised regulatory proposal*, January 2010, p. 45.
1018 Energex, *Revised regulatory proposal*, January 2010, pp. 45–46.
1019 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 197.
1020 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 196.
1021 Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 197–198.

13.3 Issues and AER considerations

13.3.1 Pass through event materiality threshold

AER draft decision

The AER recognised exclusions set out in section 2.3.2 of the EBSS as costs excluded from the operation of the EBSS for Qld DNSPs.[1022] Section 2.3.2 of the EBSS provides for approved increases or decreases in actual opex associated with recognised pass through events to be excluded from the actual and forecast expenditure amounts used to calculate carryover gains or losses under the EBSS.[1023] The AER determined that for Qld DNSPs a general nominated pass through event must be material and that the materiality threshold required the costs associated with the event to exceed 1 per cent of the smoothed revenue allowance specified in the final decision in each of the years of the regulatory control period that the costs are incurred.[1024]

Revised regulatory proposal

Energex submitted that uncontrollable opex that meets the relevant criteria under clause 6.6.1(j) of the NER but fails the AER's general nominated pass through event materiality threshold should be excluded from the operation of the EBSS. It stated that the intention of the EBSS is to achieve efficiency over the costs that a DNSP can control. Energex has estimated the materiality threshold for general nominated pass through events at $12 million.[1025]

Energex also noted that the AER provided ETSA Utilities the exclusion from a materiality threshold for uncontrollable expenditure that the meets the relevant criteria in the NER.[1026]

AER considerations

In its draft decision for ETSA Utilities, the AER applied two criteria in assessing whether an opex category should be excluded from the EBSS:[1027]

- whether or not the opex is controllable
- how actual expenditure for that cost category is used in setting opex forecasts for the following regulatory control period.

The AER considered that ETSA Utilities' opex associated with uncontrollable events should be excluded from the EBSS, irrespective of whether the cost impact of the event satisfied the cost pass through materiality threshold. This was considered by the AER to be consistent with the position that a DNSP should not be rewarded or penalised under the EBSS for costs which are beyond its control. Any such costs

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1022 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 315.
1023 AER, *Electricity distribution network service providers: Efficiency benefit sharing scheme*, p. 7.
1024 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 348.
1025 Energex, *Revised regulatory proposal*, January 2010, p. 45.
1026 Energex, *Revised regulatory proposal*, January 2010, p. 45.
1027 AER, *Draft decision, South Australia draft distribution determination 2010–11 to 2014–15*, November 2009, p. 373.

would be assessed by the AER on a case by case basis, with due consideration of the relevant factors under clause 6.6.1(j) of the NER.[1028]

The EBSS requires a DNSP to propose cost categories for exclusion from the EBSS in its regulatory proposal prior to the commencement of the regulatory control period during which the EBSS will be applied.[1029] The AER considers that Energex's proposal that recognised general nominated pass through events should be exempt from a materiality threshold for the purposes of the EBSS has been proposed prior to the commencement of the regulatory control period during which the EBSS will be applied for Energex.

The AER also considers it appropriate to apply the principles and operation of its EBSS consistently between DNSPs.

For these reasons, the AER considers it appropriate that the Qld DNSPs' opex associated with uncontrollable events should be considered for exclusion from the EBSS, irrespective of whether the cost impact of the event satisfies the relevant cost pass through materiality threshold.

Uncontrollable cost events that the AER determines should be excluded for the purposes of the EBSS carryover calculations will not necessarily be recognised as approved pass through events for any other purposes under the NER or this decision.

13.3.2 CONFIDENTIAL

[redacted]

AER considerations

[redacted]

[redacted]

13.3.3 Annual reporting requirements

Ergon Energy proposed the reporting deadline for the EBSS be 31 October of each year.

[1028] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 374.
[1029] AER, *Electricity distribution network service providers: Efficiency benefit sharing scheme*, p. 6.

AER considerations

Appendix Q of the draft decision provides details of certain information that will be required to be reported by the Qld DNSPs on an annual basis. Appendix Q includes details of actual opex to be reported by the Qld DNSPs for the purpose of determining the rolling carryover amount each year for the application of the EBSS.

The AER has yet to finalise an annual regulatory reporting framework for Qld DNSPs. For this reason the AER considers it appropriate that Qld DNSPs defer to the QCA's timelines for the reporting of financial information. The QCA requires financial information to be reported on a financial year basis within four calendar months of the end of the regulatory reporting period.[1030] On this basis, the AER accepts Ergon Energy's submission that the reporting deadline for the EBSS be 31 October of each year. For the purpose of regulatory consistency, the AER will also apply the same timeline for the reporting of opex information for the EBSS to Energex.

13.3.4 Treatment of Energex's network insurance costs

The AER notes that Energex included attritional liability claims (liability claims below $100 000 per event) within the insurance costs overhead category.[1031] In accordance with the AER's EBSS final decision, the AER considers that, due to the frequency of these low cost events, attritional liability claims are ongoing business costs, and thus should be included in Energex's total opex for EBSS purposes.[1032] Energex's attritional liability claims were also derived using historical costs.[1033] For these reasons the AER considers that attritional liability claims should not be grouped with insurance costs, and should thus be subject to the EBSS.

13.4 AER conclusion

The AER will apply the EBSS in accordance with its framework and approach paper for the Qld DNSPs published in November 2008.[1034]

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the demand management innovation allowance (DMIA)

[1030] QCA, *Electricity Distribution: Regulatory Reporting Guidelines Version 4.1*, November 2005, p. 21.

[1031] Energex, *Regulatory proposal*, July 2009, pp. 174–175.

[1032] AER, *Final decision, Electricity DNSPs EBSS*, June 2008, *Attachment E – Efficiency benefit sharing scheme*, p. 6.

[1033] Energex, email response, PB.EGX.VP.55, 24 August 2009, confidential.

[1034] AER, *Final framework and approach paper: Application of schemes*, November 2008.

- other specific uncontrollable costs incurred and reported by the Qld DNSPs during the next regulatory control period, which the AER considers should be excluded after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and EBSS.

These excluded costs will be recognised in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS, which include non-network alternatives and recognised cost pass through events. For clarity, a recognised cost pass through event is an event that satisfies the relevant materiality threshold and is approved by the AER.

[redacted]

Based on the Qld DNSPs' revised regulatory proposals, the forecast controllable opex for Energex and Ergon Energy are outlined in tables 13.1 and 13.2 respectively and will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[1035]

Table 13.1: AER conclusion on Energex forecast controllable opex for EBSS purposes ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Total forecast opex[a]	317.6	319.4	328.3	336.3	332.5
Adjustment for debt raising costs	–4.1	–4.6	–5.0	–5.5	–5.9
Adjustment for insurance costs[b]	–2.0	–2.0	–2.0	–2.0	–1.9
Adjustment for self insurance costs	–1.0	–1.0	–1.0	–1.0	–1.0
Adjustment for non–network alternatives	–3.4	–3.4	–3.5	–3.5	–3.5
Adjustment for superannuation costs	–2.5	–2.5	–2.5	–2.6	–2.6
Total opex for EBSS purposes	304.6	305.9	314.3	321.7	317.6

(a) Total opex excludes DMIA.
(b) excludes attritional liability claims.

[1035] AER, *Electricity DNSPs EBSS*, June 2008, pp. 5–7.

Table 13.2 AER conclusion on Ergon Energy forecast controllable opex for EBSS purposes ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Total forecast opex	351.3	368.4	368.2	362.7	350.6
Adjustment for debt raising costs	–3.7	–4.1	–4.4	–4.8	–5.1
Adjustment for insurance costs	–3.0	–3.0	–3.0	–3.0	–3.0
Adjustment for self insurance costs	–0.8	–0.8	–0.8	–0.8	–0.8
Adjustment for non–network alternatives	–11.6	–12.3	–12.4	–12.5	–12.5
Adjustment for superannuation costs	–4.5	–4.3	–1.2	–1.1	–0.9
Adjustment for DMIA	–1.0	–1.0	–1.0	–1.0	–1.0
Total opex for EBSS purposes	326.7	342.9	345.4	339.5	327.3

13.5 AER decision

In accordance with clause 6.12.1(9) of the NER, the EBSS to apply to Energex is as set out in the AER's *Final Framework and approach paper, Application of schemes, Energex and Ergon Energy 2010–15*, published in November 2008.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the demand management innovation allowance
- other specific uncontrollable costs incurred and reported by Energex during the next regulatory control period, which the AER considers should be excluded after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and the EBSS.

These excluded costs will be recognised in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS, which include non–network alternatives and recognised cost pass through events.

In accordance with clause 6.12.1(9) of the NER, the EBSS to apply to Ergon Energy is as set out in the AER's *Final Framework and approach paper, Application of schemes, Energex and Ergon Energy 2010–15*, published in November 2008.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the demand management innovation allowance
- other specific uncontrollable costs incurred and reported by Ergon Energy during the next regulatory control period, which the AER considers should be excluded after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and the EBSS.

These excluded costs will be recognised in addition to the adjustments and exclusions set out in section 2.3.2 of the EBSS, which include non–network alternatives and recognised cost pass through events.

In accordance with clause 6.3.2(a)(3) of the NER, the EBSS to apply to the Qld DNSPs is as specified in section 13.4 of this decision.

14 Demand management incentive scheme

This chapter sets out the AER's demand management incentive scheme (DMIS) to apply to the Qld DNSPs for the next regulatory control period. The objective of the DMIS is to provide additional incentives for DNSPs to pursue and implement efficient and innovative non–network solutions to address peak demand and other constraints on distribution networks. The DMIS operates in conjunction with existing incentives in the regulatory framework in pursuit of these objectives. Demand management refers to measures undertaken by a DNSP to meet consumer demand by shifting or reducing demand rather than by undertaking network augmentation.

This chapter reviews the issues raised in response to the draft decision and sets out the AER's considerations and conclusions on how the DMIS will apply to the Qld DNSPs in the next regulatory control period.

14.1 AER draft decision

The AER stated that it would apply only the Part A – demand management innovation allowance (DMIA) component of the DMIS to the Qld DNSPs, as outlined in its AER's framework and approach. The DMIA would be capped at $5 million for each DNSP in the next regulatory control period. The capped amount would be allocated as an ex–ante annual allowance of $1 million, for each year of the next regulatory control period.[1036]

The ex–post review and operation of the DMIA would be as set out in the DMIS.[1037]

14.2 Revised regulatory proposals

14.2.1 Energex

Energex did not comment on the application of the DMIS.

14.2.2 Ergon Energy

Ergon Energy accepted the introduction of the DMIS in the form of the Part A – DMIA component in the next regulatory control period.

Ergon Energy noted the additional reporting requirements set out in the DMIS and summarised in Appendix Q of the draft decision, and proposed that consistent with the Ring–fencing compliance and regulatory reporting statements, the reporting deadline be set at 31 October of each year.

14.3 Submissions

The AER received submissions from the Queensland Council of Social Service (QCOSS)[1038], UnitingCare Wesley (UnitingCare)[1039] and the Total Environment Centre (TEC)[1040] regarding the DMIS and demand management more broadly.

[1036] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 321.
[1037] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 321.

QCOSS

QCOSS stated that the DMIS is only a small step toward encouraging demand management and the current framework continues to incentivise DNSPs to focus on augmentation alone. QCOSS proposed that changes be made to the regulatory framework to allow for greater innovation and expenditure on alternatives to augmentation. QCOSS also stated that the AER needs to consider different options for funding demand management expenditure rather than increasing costs to all consumers.[1041]

UnitingCare

UnitingCare submitted that the demand management expenditure for Ergon Energy, Energex and ETSA Utilities across the next regulatory control period amounted to only $13 million and was miserly compared to the expected revenues for these DNSPs. For the Qld DNSPs, UnitingCare suggested that only $10 million will be jointly spent by the Qld DNSPs, compared to their joint expected revenues of approximately $13.5 billion over the next regulatory control period.[1042]

While recognising that there is no established benchmark for demand management expenditure as a percentage of revenue, UnitingCare submitted that there are very few successful billion dollar businesses that would have a research and development (R&D) budget below 1 per cent of revenue. UnitingCare submitted that demand management should be regarded as the most important R&D matter for DNSPs.[1043]

UnitingCare proposed that the benchmark be set at 0.2 per cent of expected revenue for DNSPs. It suggested that 0.2 per cent be set as the level of expenditure for the final year of the next regulatory control period, 0.08 per cent be set for the first year, and appropriate incremental increases be set for years 2–4. Further, UnitingCare suggested that DNSPs would need to submit their demand management strategies to the AER for approval and then have their implementation audited annually.

Total Environment Centre

The TEC submitted that the AER, the MCE and AEMC have all failed to implement a regulatory framework that prioritises demand management above what it claimed to be inefficient network expansion.[1044] It submitted that the Qld DNSPs have underutilised demand management, instead opting for peak driven network expansion, and that this is inefficient and irresponsible in the context of unnecessary electricity price increases and Australia's greenhouse emissions.

The TEC submitted that demand management is by far the most cost effective option, claiming that it is almost four times more cost effective than network augmentation. It added that this cost effectiveness is further enhanced when compared to the carbon costs payable to consumers that will continue to rise particularly after the introduction

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[1038] QCOSS, *Submission on the AER's draft decision*, February 2010, p. 3.
[1039] UnitingCare, *Submission to the AER – Distribution price reviews*, February 2010, p. 10.
[1040] TEC, *Submission to the AER*, February 2010, pp. 1–2.
[1041] QCOSS, *Submission on the draft decision*, February 2010, p. 3.
[1042] UnitingCare, *Submission to the AER, February 2010*, p. 10.
[1043] UnitingCare, *Submission to the AER*, February 2010, p. 10.
[1044] TEC, *Submission to the AER*, February 2010, p. 2.

of a carbon price in Australia.[1045] It stated that despite this, the Qld DNSPs are proposing to spend less than 2 per cent of their capex and opex allowances on demand management. The TEC considered that these amounts, combined with the sizes of the allowances under the DMIA, demonstrated a flippant dismissal of demand management by the AER and the Qld DNSPs.

The TEC submitted that it is the responsibility of the AER to act in the long term interests of consumers by ensuring that the most cost-effective solution to meeting demand growth is selected by the DNSPs.[1046] The TEC called for regulatory reforms to change network culture and dramatically increase the amount of demand management being undertaken. It proposed that the AER or individual jurisdictions implement mandatory peak demand management for distribution networks.[1047] It stated that this was particularly required in the case of Energex, given its supposed previous successes in the area of demand management.[1048]

14.4 Issues and AER considerations

Issues raised by Ergon Energy

The AER notes Ergon Energy's proposal that the deadline for the annual reporting requirements associated with the DMIA be 31 October of each year in the next regulatory control period. The AER considers that Ergon Energy's request is practical in that it would ensure consistency of timing with other regulatory reporting requirements, including those pertaining to ring–fencing.

As such the AER considers it reasonable that the date for submission of Qld DNSPs' annual reporting requirements under the DMIA, be set at 31 October of each year.

Issues raised in submissions

In response to QCOSS, the AER notes that the DMIS is not intended to be the sole or even primary source of cost recovery for demand management expenditure. The DMIS is specifically focussed on innovation and is designed to complement the broader regulatory framework.

The AER notes that the primary sources of demand management expenditures are through the capex and opex allowances approved by the AER as part of this decision, in accordance with clauses 6.5.6 and 6.5.7 of the NER. As part of this decision, the AER has approved a significant amount of approximately $221 million in demand management expenditure for the Qld DNSPs, including capex and opex. The AER notes that the figures quoted by UnitingCare appear to only relate to expenditures funded under the Part A – DMIA, and do not include the demand management programs in the capex and opex forecasts for the Qld DNSPs.

With regard to QCOSS' proposal, that the AER find ways of funding demand management without increasing the costs to all consumers, the AER does not consider that this would be feasible or practical. The AER also notes that currently the benefits

[1045] TEC, *Submission to the AER*, February 2010, pp. 2–3.
[1046] TEC, *Submission to the AER*, February 2010, p. 3.
[1047] TEC, *Submission to the AER*, February 2010, p. 3.
[1048] TEC, *Submission to the AER*, February 2010, p. 2.

of demand management, that is, lower or deferred network augmentation capex are not partitioned to particular consumers but indeed shared throughout the network.

Finally, the AER also notes UnitingCare and the TEC have suggested that demand management is by far the most cost effective approach and further that the AER should consider setting benchmarks for demand management expenditure. The AER notes that the DMIS' role is not one of imposing but rather providing incentives for demand management. The DMIS complements the broader regulatory framework by providing incentives for DNSPs to innovate and build capacity and capabilities in the area of demand management, so as to increasingly identify efficient demand management options in future.

Further, the NER does not confer on the AER an interventionist role with regard to demand management. In assessing a DNSP’s forecast opex and capex in accordance with the criteria set out in clauses 6.5.6 and 6.5.7 of the NER, the AER needs to ensure that a DNSP has sufficiently considered and made provision for efficient non-network alternatives (that is, demand management). These clauses require the AER to assess whether a DNSP undertakes the process of evaluating network versus demand management alternatives, but do not confer on the AER an ability to impose demand management. When a DNSP identifies as part of this evaluation process, an efficient demand management option then it can submit this to the AER for assessment under the NER, as part of its opex and capex proposals.

While in some cases demand management might prove efficient, the AER notes that it does not follow that demand management is always the most efficient option. This point has also recently been acknowledged as part of the AEMC’s review of demand-side participation in the NEM, particularly in regard to similar submissions from the TEC and other stakeholders.[1049] The AER considers that it is prudent for the DNSP to be responsible for determining which option is more efficient. The Qld DNSPs have indeed identified certain projects as part of their capex and opex proposals for the AER to assess. In doing so the AER has deemed that the projects submitted by the Qld DNSPs are largely efficient, with the exception of some projects. These exceptions demonstrate that for the AER to impose demand management as a matter of course, could potentially lead to inefficient outcomes and the imposition of inefficient burdens on consumers.

14.5 AER conclusion

The AER will apply the Part A – DMIA component of the DMIS to the Qld DNSPs as outlined in the draft decision. The DMIA will be capped at $5 million for each business over the next regulatory control period. The capped amount will be allocated to each business as an ex–ante annual allowance of $1 million, for each year of the next regulatory control period as part of this final decision.

The ex–post review and operation of the DMIA will be as set out in the DMIS.

[1049] AEMC, *Final report, Review of demand-side participation in the NEM*, December 2009, p. 21.

14.6 AER decision

In accordance with clause 6.12.1(9) of the NER, the DMIS to apply to Energex is the DMIS set out in the AER's *Demand management incentive scheme – Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008.

The Part A – DMIA component of the DMIS will apply to Energex. The DMIA will be capped at $5 million for the next regulatory control period and allocated to Energex in equal annual instalments of $1 million for each year of the next regulatory control period, as specified in section 14.5 of this decision.

In accordance with clause 6.12.1(9) of the NER, the DMIS to apply to Ergon Energy is the DMIS set out in the AER's *Demand management incentive scheme – Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008.

The Part A – DMIA component of the DMIS will apply to Ergon Energy. The DMIA will be capped at $5 million for the next regulatory control period and allocated to Ergon Energy in equal annual instalments of $1 million for each year of the next regulatory control period, as specified in section 14.5 of this decision.

In accordance with clause 6.3.2(a)(3) of the NER, the DMIS to apply to the Qld DNSPs is as specified in section 14.5 of this decision.

15 Pass through arrangements

This chapter sets out the AER's assessment of the Qld DNSPs' proposed pass through events to apply during the next regulatory control period. A pass through is a mechanism which allows the approved revenue of a DNSP to be adjusted during a regulatory control period. The event can be either positive or negative for a DNSP's costs but needs to be of such significance that the approved revenue allowance is no longer appropriate. That is, taking account of the fact that a revenue allowance is based on the best available forecasts when the determination is made and the flexibility a DNSP has to revise its business plans in accordance with changed circumstances, the event means that there is a significant risk that the national electricity objective in section 7 of the NEL will not be met.

The pass through mechanism recognises that an efficient revenue allowance cannot be established with complete certainty and that it may not be efficient to require DNSPs to manage all situations or circumstances through their revenue allowance. At the same time, the incentive properties of this revenue allowance—as opposed to a regulatory regime which only provides revenue for approved purposes—means that pass through events are limited to events which are beyond the control of the DNSP and where there is a significant risk that the national electricity objective will not be met without an adjustment to the DNSP's approved revenue.

An objective of the incentive framework is to ensure that risks are appropriately managed. The risks include, amongst other things, the potential for costs to be incurred that might otherwise be avoided or mitigated if managed appropriately. The incentive framework provides a DNSP with a revenue cap over the regulatory control period based on forecast cost of providing standard control services. The DNSP is therefore has incentives to find means of avoiding or reducing costs as any savings are generally retained by the DNSP until the next regulatory reset. While the incentive to find efficiencies is desirable, it also creates an incentive to avoid, reduce or seek to pass through costs irrespective of the efficiency of doing so. If a DNSP fails to manage risks properly and incurs additional costs it would be expected to bear those costs and should not be able to pass through those costs to its customers. However, the NER recognises that a DNSP can be exposed to risks beyond its control and which may have a material impact on its costs and, as a result, on the ability of the DNSP to provide standard control services.

One means of dealing with such outcomes is the pass through provisions contained in the NER. These provisions allow uncontrollable material changes (both increases and decreases) in the costs of providing direct control services to be passed through to distribution network users during a regulatory control period. This pass through of costs is achieved through an amendment to the price or revenue determination.

15.1 AER draft decision

The AER divided pass through events into two broad categories: specific nominated pass through events and a general nominated pass through event. Where the AER did not accept that a proposed pass through event should be accepted as a specific nominated pass through event, it would remain possible for a DNSP to seek to pass through costs associated with an event under the provisions of the general nominated pass through event. The key difference between specific and nominated events was the materiality threshold that the AER considered should be exceeded before the costs associated with an event may be passed through.

The AER's approach in the draft decision was in accordance with the pass through provisions in the NER.

Clause 6.12.1(14) of the NER requires the AER to make a constituent decision on the additional pass through events that are to apply for the regulatory control period.

The definition of pass through event in chapter 10 of the NER provides that the following events are pass through events in a distribution determination:

- a regulatory change event
- a service standard event
- a tax change event
- a terrorism event.

The chapter 10 definition of pass through event also provides that:

> An event nominated in a distribution determination as a pass through event is a pass through event for the determination (in addition to those listed above).

The AER considers it has a broad discretion in determining the additional pass through events that are to apply in a regulatory control period. Clause 6.12.1(14) of the NER does not limit the AER's discretion and the definition in chapter 10 provides little guidance of the types of matters that may constitute additional pass through events. While certain pass through events are specified in chapter 10, these events are disparate in nature. For example, a terrorism event is vastly different to a tax change event. Even if it is considered that there are certain commonalities between the events specified in chapter 10, this does not prevent the AER from also having regard to other matters in formulating the criteria for additional pass through events. Therefore, these events afford the AER little assistance in determining the additional pass through events that are to apply in a regulatory control period. Nor do these events limit the AER's discretion.

Clause 6.12.3 of the NER confirms the breadth of the AER's discretion. In particular, clause 6.12.3(a) states that:

> Subject to this clause and other provisions of this Chapter 6 explicitly negating or limiting the AER's discretion, the AER has a discretion to accept or approve, or to refuse to accept or approve, any element of a regulatory proposal.

While clause 6.12.3(f) generally limits the AER's discretion in clause 6.12.1(14), the limit in this clause only applies to the AER's refusal to approve an amount or value. A pass through event cannot properly be described as an *amount* or a *value*.

The exercise of the AER's discretion is, however, subject to the national electricity objective in section 7 of the NEL and the revenue and pricing principles in section 7A of the NEL.

The AER considers that its conceptual approach to the treatment of pass through events results in outcomes that are consistent with the national electricity objective which states:

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

The AER considers that its treatment of pass through events will promote the long term interests of consumers by ensuring that prices reflect network operating costs and that, to the extent that the revenue allowance is adjusted, it is only adjusted for events that are beyond the control of the DNSP.

The AER also considers that its approach is consistent with the revenue and pricing principles contained in the NEL. The principles which are particularly relevant to the treatment of pass through events are as follows:

> (2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in –
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.
>
> (3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes -
>
> (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
>
> (b) the efficient provision of electricity network services; and
>
> (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> (5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

Paragraphs 7A (2)(a) and (b) of the NEL provide that DNSPs should be able to recover at least the efficient costs the operator incurs in providing direct control network services and complying with regulatory obligations or requirements. The AER notes costs that are uncontrollable (or controllable but of a high magnitude) are only passed through where they are not recoverable elsewhere in the regulatory regime and to do otherwise would allow DNSPs to recover above the efficient costs of delivering direct control services. The AER acknowledges the need for DNSPs to recover the efficient costs associated with meeting regulatory obligations or requirements that are not recovered elsewhere. The AER considers the appropriate mechanism for the recovery of these costs is through the pass through events contained in the NER (including additional pass through events described in a distribution determination). This will necessarily align the policy intent of the NEL with the provisions of the NER.

In relation to section 7A(3) of the NEL, the AER notes that DNSPs should be provided with incentives to efficiently provide network services. To promote this objective, the AER has included in its pass through event assessment criteria, the requirement that pass through events are beyond the control of the DNSPs. The AER considers that restricting pass throughs to events that are beyond the reasonable control of the DNSPs is consistent with the incentives of the ex–ante regulatory framework, which does not adjust regulatory allowances in light of actual circumstances. In contrast, by allowing the costs associated with events that are within the control of the DNSPs as a pass through would undermine the incentives of the regulatory regime. Accordingly by restricting pass through events that are beyond the control of the DNSPs the AER is ensuring that costs which can be mitigated by the DNSP are not being passed through to consumers. This is also consistent with the AER's view that the cost associated with risks which cannot be readily managed should lie with the party who is best placed to bear the risk—that is the DNSP or users.

The AER, in accordance with the discretion conferred on it by the NER, devised eight criteria for assessing whether an event nominated by a DSNP would constitute a specific nominated pass through event for the regulatory control period. The AER noted that for all pass through events, the occurrence of an event must impose material costs on the provision of direct control services by an affected DNSP. However, the AER considered that for specific nominated events that satisfied the AER criteria, a lower materiality threshold would be applied.

The AER accepted the following nominated pass through events for the Qld DNSPs (the first three being specific nominated events):

- smart meter event
- carbon pollution reduction scheme (CPRS) event
- feed–in tariff event
- a general nominated pass through event.

The AER considered that the other proposed pass through events did not meet the AER's assessment criteria for a specific nominated pass through event. In many instances the AER considered the proposed events were likely to be regulatory change events or fit the definition of a general nominated pass through event.

For general nominated events the AER will apply a materiality threshold of 1 per cent of the smoothed revenue allowance specified in the distribution determination for each of the years of the regulatory control period in which the costs are incurred. The AER will apply a materiality threshold to specific nominated events set to the administrative costs of assessing an application.

15.2 Revised regulatory proposals

15.2.1 Energex

Energex proposed two additional specific nominated pass through events: a significant storm event and a retailer failure event.

Energex did not raise any other issues in regard to any other aspects of the draft decision including those pass through events that were rejected by the AER or the issue of the materiality threshold that should be applied to general nominated pass through events.

15.2.1.1 Significant storm event

Energex did not agree with AER's rejection of self insurance for storm events exceeding $2 million.[1050] Energex considered that, as a consequence, it faced an unmitigated exposure to significant storm events that have an impact of between $2 million and the threshold for a general nominated pass through event (estimated at around $12 million). Consequently, Energex proposed a specific nominated pass through event for storms of this type on the basis these events satisfied the AER criteria for nomination of such event.[1051]

Energex considered that a significant storm event should be regarded as a specific nominated pass through event as these events are foreseeable and frequently affect its network. Energex referred to the Finity report which suggested that such events would occur in 1 out of every 4 years. Accordingly, Energex asserted that this type of event satisfies the criteria set out in the draft decision. Energex's proposed definition of a significant storm event was:[1052]

> The incurring of costs by Energex as a result of a storm during the course of the 2010–2015 regulatory control period to the extent those costs exceed $2 million.

15.2.1.2 Retailer failure event

Energex further proposed retailer failure as a specific nominated pass through event.[1053] The event was proposed by Energex as a result of the rejection of its self insurance allowance for retailer credit risk in the draft decision. The AER indicated that should it occur, a retailer credit risk event may constitute a general nominated

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[1050] Energex, *Revised regulatory proposal*, January 2010, p. 47.
[1051] Energex, *Revised regulatory proposal*, January 2010, p. 48.
[1052] Energex, *Revised regulatory proposal*, January 2010, p. 48.
[1053] Energex, *Revised regulatory proposal*, January 2010, p. 49.

pass through event. However, Energex considered that a retailer failure meets the AER's criteria for a specific nominated event for the following reasons:

- the AER's rejection of self insurance for retailer credit risks
- the AER's rejection of the $5 million cap for a general nominated pass through event
- the recent failure of retailer Jackgreen (International) Pty Ltd[1054] which demonstrated the likelihood of the occurrence of such an event.

Energex proposed that a pass through event for retailer failure be defined as follows:[1055]

> The incurring of costs (default payment) by Energex during the course of the 2010–15 regulatory control period due to a retailer failure. A retailer failure event is an event when the Australian Energy Market Operator Limited (AEMO) has issued a suspension notice to a retailer under clause 3.15.21(f) Rules.

15.2.2 Ergon Energy

Ergon Energy accepted or agreed with many of the approaches in the draft decision. However, Ergon Energy sought clarification from the AER on a number of matters and proposed three additional pass through events it considered should be included as specific nominated pass through events.

15.2.2.1 Pass through assessment criteria

Ergon Energy sought clarification on whether the criteria used by the AER to determine if a nominated pass through should be accepted would also be applied to events defined under the NER or general pass through events.[1056]

15.2.2.2 Materiality threshold

Ergon Energy sought clarification from the AER on the materiality threshold that would be applied to the different types of cost pass through events, that is, events defined in the NER, general nominated events and specific nominated events. Ergon Energy considered that events defined in the NER should have a materiality threshold based on the administrative costs of assessing the pass through application. Ergon Energy suggested that such a threshold should be applied because, like specific nominated events, the costs of such events cannot be forecast on a reliable basis at the time the regulatory determination is made.

Ergon Energy also sought clarification from the AER on its intended approach in respect of the calculation of a threshold for a particular eligible pass through amount. Ergon Energy considered that the 1 per cent threshold should apply to the costs associated with the event, not the revenues. Ergon Energy suggested there were contradictory references to costs and revenues in the AER's Final Decision for NSW

[1054] Jackgreen (International) Pty Ltd is an energy retailer that was suspended from trading in the national electricity market by AEMO on 18 December 2009.

[1055] Energex, *Revised regulatory proposal*, January 2010, p. 49.

[1056] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 202.

DNSPs. Ergon Energy set out how it considered a threshold would be calculated and applied in two hypothetical examples.[1057] In particular, Ergon Energy suggested that where an event imposes costs over a number of years, the materiality of the event should be measured by comparing the total cost of the event over multiple years to the revenue requirement in the year in which the event occurs.

15.2.2.3 AER rejection of certain pass through events

Ergon Energy noted that the AER had rejected certain events on the basis that such events would likely constitute an event that was already defined in the NER.[1058] These included:

- change in minimalist transitioning approach
- transfer of regulatory functions to a national framework or change to reporting requirements
- network obligations in relation to electric and magnetic fields
- changes in tax and other levies.

Ergon Energy sought an assurance from the AER that if one of these events was to occur and it was considered by the AER to not constitute a pass through event as defined in the NER, then the AER would 'administer the Rules in a manner that is consistent with the spirit of its Distribution Determination with respect to the treatment of these events'.[1059]

A similar assurance was sought by Ergon Energy in relation to those events rejected by the AER on the basis that each such event constitutes a general nominated pass through event. These events include a distribution loss event, force majeure and a change in business structure.

15.2.2.4 Unfunded shared network event

In its regulatory proposal, Ergon Energy proposed that unfunded shared network costs should be included by way of an adjustment to the annual revenue requirement in its proposed control mechanism. Ergon Energy noted in its revised regulatory proposal that the AER had indicated in its draft decision that the adjustments for feed-in tariffs and unfunded shared network costs were discussed in chapter 15, 'Cost pass through'. However, Ergon Energy stated that the AER had not discussed unfunded shared network costs in chapter 15.[1060]

In its revised proposal, Ergon Energy maintained its position that unfunded shared network costs should be accommodated by an adjustment to its control mechanism. However, Ergon Energy considered that if the AER did not agree to this, it should

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[1057] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 203.
[1058] The definition of pass through event in Chapter 10 of the NER provides that a regulatory change event, a service standard event, a tax change event and a terrorism event are pass through events.
[1059] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 207.
[1060] The AER acknowledges that as 'unfunded shared network event' was not proposed as a pass through event in Ergon Energy's regulatory proposal the event was not discussed in the pass through chapter of the draft decision.

accept a specific nominated cost pass through event. Ergon Energy considered such an event was highly likely and would include standard control services that could not be recovered through alternative control pricing or through insurance. Ergon Energy suggested the pass through of these costs would not undermine the incentive arrangement in the regulatory regime as the cost would only be incurred if large customers were unexpectedly connected to the network.[1061]

15.2.2.5 Pass through events accepted by the AER

In relation to the CPRS event, Ergon Energy proposed a refinement to the definition of this event in the draft decision. The revisions proposed by Ergon Energy remove references to an emission trading scheme and include a reference to any mechanism by which carbon emissions are to be reduced or restricted in some manner.

In regard to the feed-in tariff event accepted by the AER in its draft decision, Ergon Energy noted that it had had initially proposed that the cost associated with this scheme be treated as an unders and overs adjustment as part of the control mechanism. Ergon Energy also noted that ETSA Utilities had proposed a revision to the NER that may lead to an alternative treatment.[1062] Ergon Energy maintained the position it had outlined in its regulatory proposal.

15.2.2.6 Additional pass through events

In its revised regulatory proposal, Ergon Energy proposed three new pass through events that it considered should be specific nominated pass through events. Ergon Energy identified one of these events as being confidential.

The second event proposed by Ergon Energy as a specific nominated event was an 'efficient energy lighting' event. The event relates to a prospective requirement of the Queensland Government to roll out energy efficient street lighting. Ergon Energy considered the event would not be otherwise captured under the existing pass through mechanism and was 'highly likely to occur as the Queensland Government is committed to finding ways for customers to be more energy efficient and reduce energy consumption'.[1063]

The third event proposed by Ergon Energy was for an 'unfunded shared network' event. This event was proposed by Ergon Energy in the event that the AER did not allow these costs to be adjusted via its control mechanism. The event stems from the requirement for Ergon Energy to build new connection to large customers, typically in remote locations, for which there are shared network expenses that cannot be recovered from the new customer. According to Ergon Energy, there is no basis on which forecasts for these types of costs can be made and, if such a cost was incurred, the cost would have a significant financial impact. Ergon Energy noted that the QCA, in the previous regulatory period, included a mechanism for accommodating unfunded shared network expenditure.

[1061] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 206.
[1062] ETSA Utilities proposed a rule change to the AEMC in December 2009 that, if approved, would permit feed-in tariffs to be recovered in pricing (in a similar manner to the recovery of TUOS) rather than through forecast opex costs or pass through.
[1063] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 209.

15.3 Submissions

Submissions that raised issues regarding cost pass through were received from SP AusNet, the Energy Users Association of Australia (EUAA) and Energex. While the submission from SP AusNet was directed toward the draft decision for ETSA Utilities it indicated that its comments were also relevant to the draft decision for the Qld DNSPs.

15.3.1 Materiality threshold

SP AusNet suggested that the AER's preference for cost pass through over self insurance would expose distribution businesses to the full cost of events that fall below the materiality threshold unless some other form of compensation is provided.[1064] In particular, SP AusNet suggested the 1 per cent of revenue threshold applied by the AER was inconsistent with the revenue and pricing principles in section 7A of the NEL insofar as a business should be provided a reasonable opportunity to recover efficient costs. SP AusNet suggested that for an event that fell just below the threshold of 1 per cent, its profits would reduce by 5 per cent in that year and this would be inconsistent with the requirements of the NEL.

SP AusNet considered that the weak incentive properties of cost pass through, which it considered was demonstrated by the AER's adoption of a 1 per cent of revenue materiality threshold to limit claims, was a reason to prefer self insurance over cost pass through mechanisms.

In its submission, Energex reiterated that the treatment of significant storm damage would create an unmitigated risk of exposure for Energex where an event did not exceed the materiality threshold.[1065]

In regard to the potential costs to Energex of a retailer failure, Energex considered that the costs of such an event exceeding $5 million should be treated as a general nominated cost pass through event. Energex noted that if the proposed pass through arrangements to be applied in the next regulatory control period had applied at the time of the failure of Jackgreen in 2009, Energex would have been be unable to claim any costs it incurred.

According to Energex, a threshold defined by 1 per cent of revenue would mean that the costs of an event below approximately $12 million would not be considered material by the AER in the first year of the next regulatory control period. Energex submitted that the AER approach of applying a set percentage of revenue for the materiality threshold is unfair. Energex disagreed that larger DNSPs have a greater capacity to respond to unexpected events because their licence conditions are more onerous.[1066] Energex also stated that a DNSP, such as itself, with a rapidly growing asset base reflecting growth and requirements to meet security, reliability and compliance obligations, faces significant risks that make it less able to re-allocate funds to manage major unforeseen events.

[1064] SP AusNet, *Submission on draft determination*, February 2010, p. 4.
[1065] Energex, *Submission on draft determination*, February 2010, p. 22.
[1066] Energex, *Submission on draft determination*, February 2010, p. 26.

Energex noted that its forecasts for efficient capex and opex do not include an allowance for unforeseen or unpredictable events.[1067] Therefore, Energex considered that, if these events cannot be funded through self insurance, cost pass through is the only means by which the costs of these events can be mitigated. Energex proposed that the threshold for unforeseen cost pass through events, which tend to be opex, should be set at 2 per cent of a DNSP's annual opex. Energex considered that such a threshold would not be biased against DNSPs with large capex programs and/or large asset bases. Furthermore, Energex suggested that a threshold based on such an approach was more stable and would address the concern the AER raised in its draft decision that the threshold should not be based a fixed amount.[1068]

15.3.2 Specific nominated pass through events

The EUAA did not agree that the AER should allow pass through events for smart meters, feed–in tariffs or CPRS. EUAA considered that pass throughs for these events would provide the DNSPs with no incentive to reduce their costs of compliance.[1069] The EUAA also submitted, in relation to smart meters, that the costs of a smart meter roll out were not difficult to forecast and that the approach to cost recovery in Victoria could serve as a model.

In its submission, Energex suggested that its proposed retailer failure event meets the criteria in the draft decision for a specific nominated event. Energex reiterated the definition of a retailer failure event included in its revised regulatory proposal.[1070]

15.4 Issues and AER considerations

15.4.1 Nominated pass through events

15.4.1.1 Energex – significant storm event

The AER notes that Energex has indicated that significant storm events could occur once every 4 years.[1071] The AER considers that events that occur with such frequency should be factored into the forecast expenditure proposal proposed by Energex. As noted in its draft decision, the AER considers that, where possible, a DNSP should include forecasts of expected capex and opex in its regulatory proposal.[1072] The AER considers that for an event that occurs on average once every 4 years Energex would have a record of historical cost impacts that could be used to forecast future cost impacts. Indeed the AER notes that one element of Energex's forecast opex is 'Emergency response/storms' with forecast costs of around $8 million per year over the next regulatory control period.[1073] Therefore, the AER does not accept that Energex faces an unmitigated risk exposure for significant storm events as an allowance for these events has already been provided.

[1067] Energex, *Submission on draft determination*, February 2010, p. 26.
[1068] Energex, *Submission on draft determination*, February 2010, p. 27.
[1069] EUAA, *Submission on draft determination – Qld DNSPs*, February 2010, p. 30.
[1070] Energex, *Submission on draft determination*, February 2010, p. 25.
[1071] Energex, *Revised regulatory proposal*, January 2010, p. 47.
[1072] AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, p. 333.
[1073] Energex, *Revised regulatory proposal*, January 2010, p. 31.

In its revised regulatory proposal, Energex indicated that it had relied on the actuarial study by Finity to determine the storm events it considered were significant and outside the scope of either the 'Emergency response/storm' opex forecast or below the threshold for a general nominated pass through.[1074] The AER sought further information from Energex regarding the two events on which Finity had derived the once in every four years probability.[1075] The events took place in January 2004 and November 2008 and had associated costs of $12.9 million and $14.7 million. The AER notes that both of these storms would have exceeded the 1 per cent of revenue threshold required for a general nominated pass through event. The AER therefore does not accept that these storms provide a basis for estimating the likelihood of a pass through event, as proposed Energex, which imposes losses of between $2 million and $12 million. On this basis, the AER considers that Energex has not demonstrated that a significant storm event is highly likely and consequently does not accept this event should be accepted as a specific nominated pass through event.

Nevertheless, the AER accepts that in certain circumstances, a significant storm event could have a material impact on the ability of Energex to provide distribution services. In the event of such storm damage, it will be possible for Energex to seek to pass through associated costs under the provisions of the general nominated pass through event. In making this decision, the AER has considered the issues raised by Energex in its revised regulatory proposal and in its submission.

15.4.1.2 Energex – Retailer failure event

The AER notes the failure of the retailer Jackgreen (International) Pty Ltd in late 2009. However, the AER does not accept that the failure of this retailer demonstrates the likelihood of the occurrence of such an event, as suggested by Energex.[1076]

In its submission, Energex indicated that the costs of the failure of Jackgreen were significant. Energex argued these costs would not be recoverable under the arrangements for general cost pass through outlined by the AER in its draft decision because the costs are less than 1 per cent of the annual revenue in that year.

The AER accepts that it is likely that such costs would not be recoverable under the arrangements for general cost pass through as the costs are less than 1 per cent of the annual revenue for the relevant year. However, the AER considers that an unexpected event that imposes a cost on a DNSP that is below 1 per cent of annual revenue in that year would not materially affect the ability of the DNSP to provide distribution services. The AER understands that a similar materiality provision exists under Energex's existing regulatory determination[1077] and that, to date, the threshold has not caused the provision of distribution services to be adversely affected in any way. For this reason alone, the AER considers that the retailer failure should not be included as a specific nominated pass through event.

[1074] Energex, *Revised regulatory proposal*, January 2010, p. 47.
[1075] Energex, response to AER question AER.EGX.RP.09 - Storm classification, 12 March 2009, confidential.
[1076] Energex, *Revised regulatory proposal*, January 2010, p. 49, confidential.
[1077] QCA, *Final Determination: Regulation of electricity distribution*, April 2005, p. 50.

In addition, notwithstanding the occurrence of the Jackgreen event, the AER continues to hold the view that a significant retailer failure is an unlikely event and one that could not be construed as being 'highly likely'. Moreover, there is an element of management control that can lessen the extent of bad debts. The AER considers that for an event to be considered for inclusion as a specific nominated pass through event, the event should be highly likely. Consequently, the AER does not consider that a retailer failure should be included as specific nominated pass through event.

In the event of a significant retailer failure, Energex would be able to seek to pass through such losses under the provisions of the general nominated pass through event but it would need to demonstrate that its business practices did not contribute to the size of the loss.

15.4.1.3 Ergon Energy – Energy efficient lighting event

Ergon Energy stated the Queensland Government is likely to introduce a requirement for the installation of energy efficient street lighting. However, Ergon Energy has not provided any indication about the timetable for the introduction of this initiative and if it is to be implemented during the regulatory control period. Nor has Ergon Energy cited any government policy initiative or announcements that would support Ergon Energy's view that this event is highly likely.[1078] In deciding to accept the specific nominated pass through events for CPRS and smart meters in the draft decision, the AER took into consideration the published schedules for the introduction of these government programs.[1079]

The AER also considers that an energy efficient lighting initiative of the Queensland Government that requires Ergon Energy to roll out certain types of street light fittings may constitute a general pass through event or a regulatory change event.

Based on the information provided by Ergon Energy, the AER does not consider that the energy efficient lighting event warrants inclusion as a specific nominated pass through event.

15.4.1.4 CONFIDENTIAL

[redacted]

[redacted]

[1078] The Office of Clean Energy, Queensland, is undertaking a trial of energy efficient street lighting that will run for 3 years until 2012. However, it is not clear what the trial outcomes will be, and if or when any requirement to install energy efficient street lighting will be implemented. See <http://www.cleanenergy.qld.gov.au/energy_efficient_street_lighting_trial_.cfm >.

[1079] AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, pp. 337–338.

[redacted]

[redacted]

15.4.1.5 Ergon Energy – Unfunded shared network event

The AER appreciates the issues of unfunded shared network expenses that Ergon Energy and other DNSPs may encounter. The AER also acknowledges that such unexpected expenses may be a more acute issue for Ergon Energy given the nature of its network and customer base. In principle, the AER considers that growth related capital expenditure on shared network assets should be included in forecast capital expenditure as this is a fundamental aspect of the regulatory regime.

The AER does not consider it appropriate to provide an automatic recovery (via the control mechanism as discussed in chapter 4 of this decision) or pass through mechanism. Instead, the AER considers that the unfunded component of these connections should be recovered based on prudent and efficient forecasts. However, as Ergon Energy considers that there is no basis on which to forecast unfunded shared network costs,[1080] the AER considers that these costs should also not be included in the building blocks. That is, if a forecast cannot be made on a reasonable basis, no forecast should be accepted. The AER also considers that Ergon Energy is best placed to manage the risks associated with unfunded shared network costs as Ergon Energy has an incentive to seek to recover these costs by including reasonable forecasts of potential capital costs.

The AER notes that while the QCA made provision for the inclusion of unfunded shared network assets by way of a cost pass through mechanism, to date this mechanism has not been utilised by Ergon Energy during the current regulatory control period. Given the apparent infrequency of these events, the AER considers this event does not satisfy the criteria that the event is highly likely and consequently does not accept this event as a specific nominated pass through event.

In the event that Ergon Energy is required to construct shared network assets in support of a new large customer connection, these assets can be included in the RAB from the commencement of the following regulatory control period.

[1080] Ergon Energy, *Regulatory Proposal*, July 2009, p. 440.

15.4.1.6 Ergon Energy – CPRS event

The AER notes that there is a high level of uncertainty regarding the future timing and form of a CPRS. While this would suggest that the event no longer meets the conditions for a specific nominated pass through event (as accepted by the AER in its draft decision), the AER considers that it would be inappropriate to reconsider the matter at this time.

By definition, a specific nominated pass through events is narrowly defined and is only excluded from forecast expenditure on the basis of uncertainty in regard to the timing and extent of costs. The proposal by Ergon Energy to broaden the definition of a CPRS event is a reflection that the timing and form of the CPRS is now less certain.

The AER considers that a broadening of the definition of this specific nominated pass through event is inappropriate. The event as defined in the draft decision will be retained as it would be inappropriate to disallow this event at this particular time.

15.4.1.7 Ergon Energy – Feed–in tariff

As noted in chapter 4, the AER does not accept that the costs associated with a feed-in tariff scheme can be accommodated by way of the control mechanism which was established through he framework and approach process. The AER is also aware of the proposed rule change put forward by ETSA Utilities. However it is not possible for the AER to make its decision on the basis of a proposed rule change.

Consequently, the AER maintains its position in the draft decision to include a feed-in tariff event as a specified nominated pass through event.

15.4.2 Materiality threshold and its application

The AER has considered a range of issues in regard to the materiality threshold including the specification of the threshold and the application of the threshold.

15.4.2.1 Specification of the materiality threshold

The AER notes Energex's concerns in relation to the materiality threshold for cost pass through events. In particular, the AER notes Energex's concerns regarding 1 per cent of annual revenue[1081] being used to determine what would constitute a material increase in the cost of providing distribution services and thereby warrant cost pass through. The AER considers that irrespective of the choice of a materiality threshold, there will undoubtedly be a range of views and preferences for alternative approaches by DNSPs and other interested parties. Indeed, in its submission, the EUAA commented that it does not support cost pass through as a matter of principle.[1082]

Energex proposed that the threshold be set against operating costs due to the capital intensive nature of its business and given that pass through events tend to be opex related. However, Energex has not provided any evidence to support this proposition. The AER is of the view that a materiality threshold set against the total annual

[1081] The definition is more precisely stated as '1 per cent of the smoothed revenue allowance specified in the distribution determination for each year of the years of the regulatory control period in which the costs are incurred'.

[1082] EUAA, *Submission on draft determination – Qld DNSPs*, February 2010, p. 30.

revenue requirement is appropriate because, ultimately, the total revenue requirement is reflective of the earnings of the DNSP over which a DNSP will have a significant measure of discretion. Notwithstanding that the building blocks approved by the AER are based on separate capex and opex allowances, a DNSP is not required to incur expenditure in precisely those proportions of opex and capex in any one year or indeed over the course of the regulatory control period.

The AER considers the approach proposed by Energex would favour businesses like Energex with relatively large asset bases but would be disadvantageous to businesses that have older, less capital intensive asset bases. The AER also notes that the approach proposed by Energex approximately halves the dollar amount of the threshold.

The NER does not prescribe the means for determining the amount of the materiality threshold.[1083] The AER notes, however, the following matters which support the adoption of a uniform 1 per cent of revenue materiality threshold:

- it has been accepted in different jurisdictions, including by the Independent Pricing and Regulatory Tribunal in NSW and the QCA (Energex's jurisdictional regulator for the current regulatory control period)
- it has been accepted by some DNSPs including Ergon Energy[1084] and Country Energy[1085], amongst others
- Energex is already subject to the threshold under its current regulatory arrangements and has successfully used this pass through mechanism on more than one occasion since 2005, including a capex pass through, despite the requirement to exceed a 1 per cent of annual revenue materiality threshold.

15.4.2.2 Application of the materiality threshold

Ergon Energy is correct in its understanding that the materiality threshold relates to the costs associated with the event. Ergon Energy is also correct in that opex costs are assessed in the year that they are incurred while capex costs incurred relate to the return on capital and depreciation costs only.

The AER acknowledges that it has not specified the materiality threshold that it considers should apply to pass through events, such as the terrorism event, set out in chapter 10 of the NER. This is because, to date, the AER has not been required, in any distribution determination it has made, to consider these defined pass through events in the NER. Notably, clause 6.12.1(14) only requires the AER to make a constituent decision on the *additional* pass through events that are to apply for a regulatory control period. Without prejudicing any decision the AER may be required to make in

1083 It is noted that the definition of the specified pass through events in chapter 10 of the NER, such as the regulatory change event, while containing a materiality threshold, do not provide for a particular amount.

1084 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 203.

1085 AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 280.

the future in respect of this matter, as a guide, the AER is likely to give strong consideration to the adoption of 1 per cent of annual revenue for such events.

15.4.3 Treatment of specific nominated events rejected by the AER

The AER notes the comments by Ergon Energy in regard to the treatment of events that the AER considered were inappropriate to accept as specific nominated events but which may otherwise be considered as either general nominated events or events that are defined in the NER.[1086] For clarity, the AER notes that the following events that were nominated by Ergon Energy and which were rejected in the draft decision, as constituting specific nominated pass through events are:

- force majeure event
- change of business structure (that is externally imposed).

The AER confirms the position it adopted in its draft decision that whether or not these events will fall into the category of the general nominated pass through event or one of the four defined events in chapter 10 of the NER, will need to be assessed at the time an application for cost pass through is made to the AER. The AER will assess any application for cost pass through with reference to this decision and the requirements of the NER and NEL.

15.5 AER conclusion

15.5.1 Specific nominated pass through events

The AER accepts the following pass through events as nominated pass through events for Ergon Energy and Energex:

> A **smart meter event** is an event which results in an obligation being externally imposed on a DNSP to install smart meters for some or all of its customers, or to conduct large scale metering trials during the course of the next regulatory control period, regardless of whether that requirement takes the form of a statutory obligation or not, and which:
>
> (a) does not fall within the following:
>
> (1) the definition of 'regulatory change event' in the NER (read as if paragraph (a) of the definition, was not part of the definition)
>
> (2) any other category of pass through event
>
> (b) materially increases the cost of the DNSP providing direct control services.
>
> A **CPRS event** is an event which results in the imposition of legal obligations on a DNSP arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth or Queensland government during the course of the next regulatory control period and which:

1086 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 207.

(a) does not fall within the following:

   i) the definition of 'regulatory change event' in the NER (read as if paragraph (a) of the definition, was not part of the definition)

   ii) any other category of pass through event

(b) materially increases the cost of the DNSP providing direct control services.

Feed-in tariff event means a change in the total amount of direct feed-in tariff payments paid by a Qld DNSP in respect of the Qld feed-in tariff scheme. For the purposes of this definition, the change in the amount of the direct tariff payments paid by the DNSP must be calculated as the difference between:

a. the amount of direct tariff payments paid by the DNSP in each regulatory year of the next regulatory control period, derived from the metered output of generators subject to the scheme and the applicable feed in tariff rate applying to the metered output; and
b. the amount of scheme direct tariff payments which were forecast for the purpose of and included in the Qld distribution determination for each regulatory year of the regulatory control period

Relevant direct tariff payments under this pass through mechanism are those paid through the operation of the *Electricity Act 1994 (Qld)*, and any amendments to this act.

15.5.2 General nominated pass through event

The AER nominates the following general pass through event for Energex and Ergon Energy:

A general nominated pass through event occurs in the following circumstances:

1: An uncontrollable and unexpected event occurs during the next regulatory control period, the effect of which could not have been prevented or mitigated by prudent operation risk management.

2: The change in costs of providing distribution services as a result of the event is material.

3: The event does not fall into any of the following definitions:

   'regulatory change event' in the NER (read as if paragraph (a) of the definition was not part of the definition)

   'service standard event' in the NER

   'tax change event' in the NER

   'terrorism event' in the NER

   'smart meter event' in this decision

   'CPRS event' in this decision

   'feed–in tariff event' in this decision.

For the purposes of this definition,

> 'material' means the costs associated with the event would exceed 1 per cent of the smoothed revenue allowance specified in this decision in each of the years of the regulatory control period that the costs are incurred.

For the reasons set out above, the AER considers that the other events proposed by the Qld DNSPs should not be nominated as specific nominated pass through events. However, the AER notes that a Qld DNSP may apply to the AER during the next regulatory control period for a pass through where a general nominated pass through event occurs. The AER will determine throughout the next regulatory control period, upon application by a DNSP, whether such event has occurred.

In assessing a Qld DNSP's application for a cost pass through (whether in relation to a specific nominated event, a general nominated event or an event defined in the NER), the AER will take into account all of the matters listed in clause 6.6.1(j)(1)–(8) of the NER. These matters include the need to ensure that a Qld DNSP recovers only incremental costs, and the efficiency of a Qld DNSP's decisions and actions in relation to the event, including whether the Qld DNSP has failed to take action to reduce the magnitude of the event.

15.6 AER decision

In accordance with clause 6.12.1(14) of the NER, the additional pass through events that apply to the Qld DNSPs for the next regulatory control period are the:

- smart meter event
- CPRS event
- feed–in tariff event
- general nominated pass through event

as defined in section 15.5 of this decision.

16 Building block revenue requirements

This chapter sets out the AER's calculation of annual revenue requirements for the Qld DNSPs, for the provision of standard control services for each year of the next regulatory control period. It also sets out the X factor values to be applied as part of the revenue caps to apply to the standard control services provided by the Qld DNSPs.

16.1 AER draft decision

The AER calculated the Qld DNSPs' revenue requirements and X factors based on its decisions regarding the building blocks.

16.1.1 Energex

The AER's draft decision resulted in a total revenue requirement for the next regulatory control period of $7158 million, compared to $7515 million proposed by Energex. The main reasons for this reduction are:

- the removal of $748 million from Energex's forecast capex
- the removal of $257 million from Energex's forecast opex
- a reduced allowance for tax, reflecting in part a higher gamma than that proposed by Energex
- a reduced allowance for equity raising costs.

Table 16.1: AER draft decision on Energex's annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	87.1	97.2	108.9	120.6	121.7
Return on capital[a]	793.8	901.4	1015.5	1133.2	1252.0
Operating expenditure[b]	320.8	327.8	341.9	357.4	359.7
Tax allowance	32.2	35.5	39.1	43.0	45.9
Capital contributions	–64.6	–68.9	–70.9	–73.6	–75.7
Revenue from shared assets	–4.5	–5.3	–6.0	–6.5	–6.0
Annual revenue requirements	1165.8	1288.7	1429.7	1575.1	1698.7
Expected revenues	1180.6	1294.2	1418.7	1555.2	1704.8
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[c] (%)	–23.03	–7.00	–7.00	–7.00	–7.00

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009.
(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

16.1.2 Ergon Energy

The AER's draft decision resulted in a total revenue requirement over the next regulatory control period of $6364 million, compared to $6776 million proposed by Ergon Energy.[1087]

Subsequent to the draft decision, Ergon Energy advised that it had made an error in the way the adjustment for labour cost escalators had been made to the opex figures provided to the AER to assist it in modelling its draft decision.[1088] This error also affected the capex forecasts (to a lesser extent) through the allocation of overheads. The AER remodelled its draft decision making the appropriate correction. This resulted in a revised total revenue requirement over the next regulatory control period of $6526 million. Based on these revised numbers, the main reasons for the reduced revenue requirement compared to that contained in Ergon Energy's regulatory proposal are:

- the removal of $1041 million from Ergon Energy's forecast capex
- the removal of $253 million from Ergon Energy's forecast opex
- a reduced allowance for tax, reflecting in part a higher gamma than that proposed by Ergon Energy
- a reduced allowance for equity raising costs.

Table 16.2: AER amended draft decision on Ergon Energy's annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	151.0	158.4	157.9	171.4	152.3
Return on capital[a]	715.1	790.7	875.1	970.0	1075.8
Operating expenditure[b]	347.7	362.0	361.5	364.0	357.2
Tax allowance	0.0	20.1	29.3	34.0	33.1
Capital contributions	–112.0	–121.2	–107.9	–117.5	–135.2
Revenue from shared assets	–3.2	–3.3	–3.4	–3.5	–3.5
Accelerated depreciation	10.4				
Annual revenue requirements	1109.1	1206.6	1312.6	1418.4	1479.6
Expected revenues	1123.9	1207.9	1298.1	1395.1	1499.3
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[c] (%)	–29.79	–4.90	–4.90	–4.90	–4.90

(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

[1087] AER, *Draft decision, Queensland draft distribution determination*, November 2009.
[1088] Ergon Energy, email to the AER, Modelling mistake that impacted on the AER's Draft Distribution Determination, 12 February 2010, confidential.

16.2 Revised regulatory proposals

16.2.1 Energex

Energex proposed a total revenue requirement for the next regulatory control period of $7569 million, compared to $7158 million allowed for in the draft decision.[1089] The components of Energex's proposed revenue requirement are shown in table 16.3.

Table 16.3: Energex's proposed annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	83.0	92.0	103.4	116.1	118.0
Return on capital[a]	789.2	909.4	1030.5	1153.8	1276.9
Operating expenditure[b]	323.5	333.9	350.3	367.1	370.7
Tax allowance	86.7	95.8	105.3	116.3	124.9
Capital contributions	–64.4	–68.5	–70.6	–73.1	–75.1
Revenue from shared assets	–4.0	–4.7	–5.5	–6.1	–5.7
Annual revenue requirements	1213.9	1357.9	1513.4	1674.0	1809.6
Expected revenues	1214.1	1348.9	1498.5	1664.8	1849.6
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[c] (%)	–26.52	–8.44	–8.44	–8.44	–8.44

Source: Energex, *Revised regulatory proposal*, January 2010, Revised PTRM, confidential.
(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

16.2.2 Ergon Energy

Ergon Energy proposed a total revenue requirement for the next regulatory control period of $7252 million, compared to $6526 million as calculated for the revised draft decision above.[1090] The components of Ergon Energy's proposed revenue requirement are shown in table 16.4.

[1089] Energex, *Revised regulatory proposal*, January 2010, Revised PTRM, confidential.
[1090] Ergon Energy, *Revised regulatory proposal*, January 2010, Revised PTRM, confidential.

Table 16.4: Ergon Energy's proposed annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	149.8	152.4	156.1	170.7	153.1
Return on capital[a]	722.0	829.0	946.9	1068.8	1199.7
Operating expenditure[b]	381.8	407.0	418.5	428.3	428.1
Tax allowance	25.5	75.1	82.4	96.9	96.1
Capital contributions	–137.3	–149.1	–132.7	–144.5	–166.2
Revenue from shared assets	–3.2	–3.3	–3.4	–3.5	–3.5
Accelerated depreciation	10.4	0	0	0	0
Annual revenue requirements	1149.1	1311.2	1467.9	1616.9	1707.3
Expected revenues	1208.1	1317.2	1436.2	1565.9	1707.3
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[c] (%)	–39.51	–6.42	–6.42	–6.42	–6.42

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, Revised PTRM.
(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

16.3 Submissions

Submissions from the Energy Users Association of Australia (EUAA), Maryborough Sugar Factory[1091] and Cement Australia indicated concerns that significant projected increases in electricity prices will impose strong negative impacts on domestic industries. Cement Australia[1092] and the EUAA[1093] noted that trade exposed industries will be particularly vulnerable to increasing costs of operations, which they will not be able to pass through to customers, and thereby placing pressure on output and jobs.

The EUAA stated that the costs the AER 'appears willing to approve' are unnecessarily high and would not satisfy the efficiency requirements of the NER or the 'long term interests of consumers of electricity' prescribed in the NEM. The EUAA stated that under a revenue cap regime, it is insufficient for the AER to only report X factors for the business in its draft decision. The EUAA noted that the QCA's 2005 final determination set out the aggregate annual revenue requirement, forecast consumption, implied nominal price (c/kWh), the annual percentage change in the nominal price, the implied real price and its annual percentage change. In

[1091] Maryborough Sugar Factory, *AER review of electricity distribution prices in Queensland*, 23 February 2010, p. 1.
[1092] Cement Australia, *AER review of electricity distribution prices in Queensland*, 16 February 2010, pp. 2–3.
[1093] EUAA, *Submission on the AER on Queensland DNSPs,* February 2010, p. 2.

keeping with this level of reporting, the EUAA urged the AER to provide greater transparency through indicative prices to ensure that the impact on end users is clear.[1094] In this context, the EUAA welcomed the AER's request that the Qld DNSPs provide sufficient notice of and earlier information on tariff changes. The EUAA noted that electricity users in NSW were notified of price increases as high as 55 per cent only two weeks before the start of the 2009–10 regulatory year.[1095]

The Queensland Council of Social Service (QCOSS) stated that it had discussed and accepted the process of cost allocation with the Qld DNSPs. However, it noted that this acceptance was based on discussions rather than formal model auditing.[1096]

The QCOSS noted that the sharp increase in peak demand driven by the air-conditioning load is having a profound effect on network prices. The QCOSS stated that it was critical for the AER to understand the negative cross subsidy effect borne by vulnerable customers as a result of network tariffs across a socio-economically diverse tariff class. The QCOSS submitted that a subset of vulnerable customers within the residential tariff class have sufficiently different cost drivers such that they could reasonably be considered as a separate tariff class under clause 6.18.3 of the NER. The QCOSS requested that the AER consider the different characteristics of low income customers in its considerations under clause 6.18.4(a) of the NER.[1097]

The QCOSS accepted that the Qld DNSPs' cost allocation processes are not sufficiently granular at present to specify a vulnerable customer class. The QCOSS proposed that Qld DNSPs coordinate with Housing and Homelessness Services (HOHS) to identify those national meter identifiers attached to HOHS dwellings. The QCOSS noted that it had proposed an alternative tariff structure aimed at vulnerable customers and indicated disappointment that the Qld DNSPs appeared to be disinterested in considering an alternative tariff design for this group of users.[1098]

16.4 Issues and AER considerations

16.4.1 Common issues

Proposed price increases and X factors

The X factors proposed by the Qld DNSPs reflect the real revenue changes for each year of the next regulatory control period. These revenue changes can be converted to average real price changes by forecasting the annual growth rate of demand for each DNSP over the next regulatory control period. The AER has forecast demand growth for Energex and Ergon Energy of 3.6 per cent and 3.0 per cent per annum respectively over the next regulatory control period.[1099] The impact on retail electricity prices can then be estimated by assuming distribution network charges make up a certain

[1094] EUAA, *Submission on the AER on Queensland DNSPs,* February 2010, pp. 3–4.
[1095] EUAA, *Submission on the AER on Queensland DNSPs,* February 2010, pp. 4–5.
[1096] QCOSS, *Submission on the draft decision*, February 2010, p. 3.
[1097] QCOSS, *Submission on the draft decision*, February 2010, pp. 2–4.
[1098] QCOSS, *Submission on the draft decision*, February 2010, pp. 4–5.
[1099] These forecast growth rates of demand are based on the forecasts approved by the AER in chapter 6 of this decision.

proportion of the overall retail price. Consistent with its draft decision, the AER has assumed distribution network charges make up 40 per cent of retail electricity prices.[1100] Table 16.5 presents the real percentage increases in retail electricity price as a result of the Qld DNSPs' proposed X factors and based on the assumptions noted above. As discussed in chapter 4 of this decision, distribution network charges will be adjusted annually for actual inflation (this approach contrasts with the approach of the QCA which set a fixed inflation rate for the five year regulatory control period).

Table 16.5: Qld DNSPs proposals – real increases in retail electricity prices (percentage, per annum)

	2010–11	2011–12 to 2014–15
Energex	8.8	1.9
Ergon Energy	14.2	1.3

Note: Calculation assumes distribution network charges make up 40 per cent of retail electricity prices and 3.6 per cent demand growth per annum for Energex and 3.0 per cent demand growth per annum for Ergon Energy for the next regulatory control period.

As noted in the draft decision, the AER must set X factors subject to the requirements of clause 6.5.9 of the NER. In particular, the X factors must:

- be set having regard to each DNSP's total revenue requirement for the next regulatory control period—the revenue requirements approved by the AER are set out in section 16.5 of this decision and are based on the blocking blocks presented in this chapter.

- minimise, as far as possible, the difference between the annual revenue requirement and expected revenue in the final year of the regulatory control period—this requirement has implications for how far the AER can go in terms of smoothing price changes. The AER's position on this matter is set out in section 16.5 of this chapter.

- for standard control services equalise, in net present value (NPV) terms, the total revenue requirement and expected revenues over the next regulatory control period under the applicable form of control—the calculation of the X factors in the post–tax revenue model (PTRM) are designed to achieve this outcome.

Clause 6.5.9(c) of the NER also provides for different X factors to be set for each regulatory year. The X factors for each year of the next regulatory control period are set out in section 16.5 of this decision.

The AER disagrees with the EUAA's assertion that the AER has approved costs that are inconsistent with the requirements and objectives of the NER. Such a broad assertion fails to appreciate the detail of the analysis and assessment that the NEL and the NER require the AER to do in making a distribution determination. For example,

[1100] The AER considers this a reasonable estimate. This figure would be 37 per cent if based on QCA, *Draft Decision: Benchmark Retail Cost Index for Electricity: 2010-11*, December 2009, pp. 2, 25.

as discussed in chapter 7, the AER considers its analysis of the capex forecasts proposed by the Qld DNSPs is extensive and consistent with the requirement that it reasonably reflects the capex criteria, as required by clause 6.5.7 of the NER.

In response to submissions from interested parties in relation to higher electricity prices, the potential for negative effects on businesses and detrimental social consequence for vulnerable consumers, it must be recognised that the revenue requirement allowed for in this distribution determination follows from each of the constituent decisions the AER must make under the requirements of the NER. The AER recognises, however, that the NEL requires it to exercise its functions and powers in a manner that will or is likely to contribute to the achievement of the national electricity objective. Relevantly, section 7 of the NEL provides:

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

In particular, the national electricity objective is set out in the context of the long term interests of consumers of electricity. The AER considers that the increased revenue requirement over the next regulatory control period achieves an appropriate trade–off in terms of price, on the one hand, and quality, safety, reliability and security of supply of electricity, on the other, in the long term interests of consumers. The AER also considers that in considering the long term interests of consumers, the NEL and the NER require it to treat all consumers equally and does not provide it with the ability to single out, for example, businesses or vulnerable customers over other consumers of electricity.

The AER notes it can not influence how the changes to distribution network charges flow through to retail prices and has made some broad assumptions (see note to table 16.5) in this decision in estimating the impact of the AER's decisions on the Qld DNSPs' X factors on retail electricity prices. The AER's decisions on the Qld DNSPs' X factors and the estimated impact on retail electricity prices are presented in section 16.5.

In any case, the AER will annually assess the proposed price changes of the Qld DNSPs. These price changes must be consistent with the control mechanisms set out in chapter 4 of this decision and clause 6.18 of the NER. The concerns raised by QCOSS regarding the allocation of costs across customer classes and the particular forms of tariffs/tariff components are governed by these requirements and will be assessed by the AER as part of the price approval process. None of the requirements of clause 6.18 of the NER would allow for the creation of a separate tariff class purely on the basis of the social concerns raised by QCOSS. The AER notes that the Qld DNSPs will also be required to publish distribution network prices on its website consistent with clause 6.18.9 of the NER.

Accuracy of existing prices and forecast sales quantities

As discussed in the draft decision, the control mechanism for the Qld DNSPs is a revenue cap. For a revenue cap, the PTRM does not require existing prices or forecast demand or customer numbers to determine the X factors. However, it is important that the forecast quantities contained in a DNSP's pricing proposal used to convert the maximum allowable revenue (MAR) each year to prices are reasonable, as required by clause 6.18.8(a)(2) of the NER. If the forecasts are not reasonable, prices will be too high or low relative to the level required for a DNSP to recover its MAR and will result in adjustments in subsequent years through the distribution use of system (DUOS) unders and overs account.[1101]

Forecast inflation

The AER considers that the forecast inflation rate for the next regulatory control period should be consistent with that used to determine the nominal weighted average cost of capital (WACC). The AER has used a forecast inflation rate of 2.52 per cent, which is marginally higher than the 2.45 per cent used in the draft decision. The basis of this forecast is discussed in chapter 11 of this decision.

16.4.2 Energex

Asset base roll forward and indexation

As discussed in chapter 5, the AER has determined the opening value of Energex's regulatory asset base (RAB) as at 1 July 2010 to be $7867 million. The AER has rolled forward Energex's RAB in the next regulatory control period using the PTRM, as shown in table 16.6.

Table 16.6: AER's roll-forward of Energex's regulatory asset base ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Opening RAB	7867.3	9002.0	10 171.9	11 344.0	12 503.2
Net capex [a]	1213.1	1257.1	1270.2	1269.4	1367.8
Indexation of the opening RAB	198.3	226.9	256.3	285.9	315.1
Straight-line depreciation	–276.7	–314.0	–354.4	–396.1	–426.6
Closing RAB	9002.0	10 171.9	11 344.0	12 503.2	13 759.4

Note: The straight-line depreciation less the indexation of the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Net capex also includes capitalised equity raising costs.

Depreciation

As discussed in chapter 10, the AER has not approved Energex's proposed depreciation allowance.

Using a post–tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the

1101 See appendix D of this decision.

(negative) straight–line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Table 16.10 shows the resulting figures.

Return on capital

The AER considers that Energex's proposed return on capital has been calculated in accordance with the PTRM. However, the amount is affected by the AER's conclusions regarding other inputs to the PTRM, such as the opening RAB (chapter 5), the forecast capex allowance (chapter 7), and the WACC parameters (chapter 11).

The AER has determined the annual return on capital allowance by applying the WACC to Energex's opening RAB for each year of the next regulatory control period. This amount is outlined in table 16.10 below.

The nominal vanilla WACC of 9.72 per cent is based on a post–tax nominal return on equity of 10.84 per cent and a pre–tax nominal return on debt of 8.97 per cent. These figures are calculated using observed market data for Energex's nominated averaging period ending 26 March 2010.

Operating expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for Energex of $1768 million (nominal) over the next regulatory control period.[1102] Table 16.10 shows the annual opex allowances.

Estimated tax payable

Using the PTRM, the AER has modelled Energex's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this draft decision. Consistent with clause 6.5.3 of the NER, the amount of tax payable is estimated using:

- a 60 per cent gearing, based on the gearing of a benchmark efficient entity, rather than Energex's actual gearing
- a statutory company income tax rate of 30 per cent as determined by the AER
- a value of imputation credits (gamma) of 0.65.

Under the post–tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost-reflective revenue outcomes. The effective tax rate is defined as the difference between pre–tax and post–tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the

[1102] This amount includes debt raising costs, demand management incentive allowance and self insurance.

PTRM, the AER has derived an effective tax rate of 25.5 per cent for this decision. Table 16.7 shows the AER's decision on Energex's tax allowance.

Table 16.7: AER decision on Energex's net tax allowance ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Tax payable	93.0	100.3	110.2	121.6	130.4
Value of imputation credits	–60.5	–65.2	–71.6	–79.0	–84.8
Net tax allowance	32.6	35.1	38.6	42.6	45.6

Note: Totals may not add due to rounding.

Capital contributions

Under clause 11.16.3(b) of the NER, Energex continued with the QCA approach to the treatment of capital contributions and included forecast capital contributions in its RAB for the next regulatory control period. To prevent customers paying twice for contributed assets, Energex has included revenue adjustments in its PTRM forecast for capital contributions in the next regulatory control period.

In its revised regulatory proposal, Energex provided revised capital contribution forecasts totalling $352 million over the next regulatory control period, compared to a total $354 million in its regulatory proposal and which were accepted by the AER in the draft decision.[1103] Energex advised in its revised regulatory proposal that its revised capital contribution forecasts applied the AER's interim real cost escalation rates.[1104] With the finalisation of the AER's real cost escalation rates (as discussed in chapter 7), the AER asked Energex to provide revised capital contribution numbers consistent with these rates, Accordingly, Energex provided revised capital contribution forecasts totalling $356 million over the next regulatory control period. The AER accepts these revised forecast capital contributions proposed by Energex as being consistent with the AER's escalation rates and clause 6.21.2(3) of the NER.

As discussed in chapter 4, the AER has rejected Energex's proposal for a capital contribution bank. Instead, the AER will require Energex to continue with the QCA approach of an annual adjustment for any under/over recovery of capital contributions against forecast being made to Energex's MAR each year.

Revenue adjustment for shared assets

Energex has included revenue adjustments in its PTRM for expected use of shared assets for alternative control services during the next regulatory control period. As part of its draft decision, the AER reviewed Energex's assessment of the expected use of these shared assets for alternative control services. Given that Energex has not revised it forecasts of the revenue adjustments significantly from the draft decision,

[1103] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 360.
[1104] Energex, *Revised regulatory proposal*, January 2010, p. 51.

the AER confirms its position that the revenue adjustments proposed by Energex for use of shared assets for alternative control services to be reasonable.[1105]

As discussed in chapter 4 of the draft decision, no annual adjustment will be made to Energex's MAR for any difference between expected and actual use of shared assets for alternative control services. This position contrasts with that for Ergon Energy, discussed below.

Revenue decrements arising from the previous periods control mechanism

In accordance with the draft decision, Energex removed from its PTRM adjustments associated with 2008–09 for under recovery of capital contributions, over recovery of DUOS and over recovery of tax. These adjustments relate to the MAR for 2010–11 and will be reflected in the prices for that year. The calculation of the MAR for each year is detailed in chapter 4.

16.4.3 Ergon Energy

Asset base roll forward and indexation

As discussed in chapter 5, the AER determined the opening value of Ergon Energy's RAB as at 1 July 2010 to be $7149 million. The AER rolled forward Ergon Energy's RAB in the next regulatory control period using the PTRM. The rolled forward amounts are shown in table 16.8.

Table 16.8: AER's roll forward of Ergon Energy's regulatory asset base ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Opening RAB	7148.9	8050.7	8928.8	9839.8	10 833.2
Net capex [a]	1046.8	1025.0	1061.3	1157.5	1269.4
Indexation of the opening RAB	180.2	202.9	225.0	248.0	273.0
Straight-line depreciation	–325.1	–349.8	–375.3	–412.1	–417.5
Closing RAB	8050.7	8928.8	9839.8	10 833.2	11 958.0

Note: The straight-line depreciation less the indexation of the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Net capex also includes capitalised equity raising costs.

Depreciation

As discussed in chapter 10, the AER has not approved Ergon Energy's proposed depreciation allowance.

[1105] In its regulatory proposal Energex proposed total revenue adjustments of $28 million for use of shared assets for alternative control services over the next regulatory control period. This figure was amended to $26 million in its revised regulatory proposal.

Using a post–tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Table 16.12 shows the resulting regulatory depreciation allowance.

Return on capital

The AER considers that Ergon Energy's proposed return on capital has been calculated in accordance with the PTRM. However, the amount is affected by the AER's conclusions regarding other inputs to the PTRM, such as the opening RAB (chapter 5), the capex allowance (chapter 7), and the WACC parameters (chapter 11).

The AER has determined the annual return on capital allowance by applying the WACC to Ergon Energy's opening RAB for each year of the next regulatory control period. The approved return on capital allowances are shown in table 16.12.

The nominal vanilla WACC of 9.72 per cent is based on a post–tax nominal return on equity of 10.84 per cent and a pre–tax nominal return on debt of 8.97 per cent. These figures are calculated using observed market data for Ergon Energy's nominated averaging period ending 26 March 2010.

Operating expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for Ergon Energy of $1942 million (nominal) over the next regulatory control period.[1106] Table 16.12 shows the annual approved opex allowances.

Estimated tax payable

Using the PTRM, the AER has modelled Ergon Energy's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this decision. Consistent with clause 6.5.3 of the NER, the amount of tax payable is estimated using:

- a 60 per cent gearing, based on the gearing of a benchmark efficient entity, rather than Ergon Energy's actual gearing
- a statutory company income tax rate of 30 per cent as determined by the AER
- a value of imputation credits (gamma) of 0.65.

Under the post–tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost-reflective revenue outcomes. The effective tax rate is defined as the difference between pre–tax and post–tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the

[1106] This amount includes debt raising costs, demand management incentive allowance and self insurance.

PTRM, the AER has derived an effective tax rate of 23.0 per cent for this decision. Table 16.9 shows the AER's decision on Ergon Energy's tax allowance.

Table 16.9: AER decision on Ergon Energy's net tax allowance ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Tax payable	27.4	78.4	84.6	98.3	95.4
Value of imputation credits	–17.8	–50.9	–55.0	–63.9	–62.0
Net tax allowance	9.6	27.4	29.6	34.4	33.4

Note: Totals may not add due to rounding.

Capital contributions

Under clause 11.16.3(b) of the NER, Ergon Energy has decided to continue with the QCA approach to the treatment of capital contributions and included forecast capital contributions in its RAB for the next regulatory control period. To prevent customers paying twice for contributed assets, Ergon Energy has included in its PTRM forecast revenue adjustments for capital contributions for the next regulatory control period.

In its revised regulatory proposal, Ergon Energy provided revised capital contribution forecasts totalling $730 million over the next regulatory control period, compared to a total $594 million in its regulatory proposal. Ergon Energy advised that these forecasts are tied to the forecasts of customer initiated capital works, which Ergon Energy adjusted upward in its revised regulatory proposal.[1107] With the finalisation of the AER's position on forecast customer initiated capital works (as discussed in chapter 7), the AER asked Ergon Energy to provide revised capital contribution numbers consistent with these forecasts. Accordingly, Ergon Energy provided revised capital contribution forecasts totalling $620 million over the next regulatory control period. The AER accepts these revised forecast capital contributions proposed by Energex as being consistent with the AER's escalation rates and clause 6.21.2(3) of the NER. The AER notes that an annual adjustment for any under/over recovery of capital contributions against forecasts will be made to Ergon Energy's MAR each year.

Revenue adjustment for shared assets

Ergon Energy has included in its PTRM revenue adjustments for expected use of shared assets for unregulated and alternative control services during the next regulatory control period. In the draft decision, the AER stated that it considered these forecast amounts to be reasonable. Ergon Energy has not amended these forecasts in its revised regulatory proposal. The AER therefore confirms its acceptance of these forecasts.

The AER notes that any difference between expected and actual use of shared assets for unregulated and alternative control services will be accounted for by an annual adjustment to Ergon Energy's MAR, as discussed in chapter 4 of this decision.

[1107] Ergon Energy, email to the AER, RE: Preliminary results of AER Modelling Request for Final Distribution Determination, 20 April 2010.

Accelerated depreciation of destroyed assets

In the draft decision, the AER decided to allow Ergon Energy to depreciate the remaining value of the assets destroyed by Cyclone Larry in March 2006 in the first year of the next regulatory control period. The value of this adjustment was $10.5 million (in nominal terms) in 2010–11. As noted in chapter 10, Ergon Energy accepted the draft decision on this matter. Therefore, the AER confirms its position in the draft decision on this matter for this decision.

16.5 AER conclusion

The AER has calculated the Qld DNSPs' revenue requirements and X factors based on its decisions regarding the building block components.

16.5.1 Energex

The AER's decision results in a total revenue requirement over the next regulatory control period of $7011 million, compared to $7569 million proposed by Energex in its revised regulatory proposal. The AER's calculation of Energex's revenue requirements and X factors is shown in table 16.10. The main reasons for the reduction are:

- the removal of $321 million from Energex's forecast capex
- the removal of $335 million from Energex's proposed tax allowance, reflecting in part a higher gamma than that proposed by Energex
- a lower WACC than that proposed by Energex.

Table 16.10: AER decision on Energex's annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	78.5	87.2	98.1	110.2	111.5
Return on capital[a]	764.5	874.8	988.5	1102.4	1215.1
Operating expenditure[b]	326.6	336.7	354.8	372.5	377.6
Tax allowance	32.6	35.1	38.6	42.6	45.6
Capital contributions	–65.1	–69.1	–71.5	–74.2	–76.4
Revenue from shared assets	–4.0	–4.7	–5.5	–6.1	–5.7
Annual revenue requirements	1133.1	1259.9	1402.9	1547.5	1667.7
Expected revenues	1135.1	1255.6	1388.9	1536.4	1699.6
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors[c] (%)	–18.20	–7.90	–7.90	–7.90	–7.90

(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

In determining Energex's X factors, the AER was mindful of the long term interest of consumers, who prefer price changes to be as smooth as possible.[1108] The AER was also mindful of clause 6.5.9(2) of the NER, which requires the divergence between the expected revenues and the annual revenue requirement for the last year of the next regulatory control period to be minimised. Balancing these factors, the AER reduced the X factors for 2012–13 to 2014–15 from –8.44 per cent to –7.90 per cent, while it reduced the X factor in 2010–11 from –26.52 per cent to –18.20 per cent. The resulting impacts in terms of retail electricity prices of the AER's decision to use these X factors, compared with Energex's proposal, is outlined in table 16.11.

Table 16.11: Retail price impacts (per cent)

	2010–11	2011–12	2012–13	2013–14	2014–15
Energex's proposal					
Real impacts	8.8	1.9	1.9	1.9	1.9
Nominal impacts	10.1	2.9	2.9	2.9	2.9
AER's decision					
Real impacts	5.6	1.7	1.7	1.7	1.7
Nominal impacts	6.8	2.7	2.7	2.7	2.7

Note: Calculations assume distribution network charges make up 40 per cent of retail electricity prices and 3.6 per cent demand growth per annum for the next regulatory control period. Inflation of 2.52 per cent assumed for calculating the nominal impacts.

The price impacts above exclude the effects of any annual revenue adjustments for such matters as under/over recovery of DUOS and any pass through costs. These adjustments will be accounted for as part of the annual price approval process.

16.5.2 Ergon Energy

The AER's decision results in a total revenue requirement over the next regulatory control period of $6554 million ($2009–10), compared to $7252 million proposed by Ergon Energy in its revised regulatory proposal. The AER's calculation of Ergon Energy's revenue requirements and X factors is shown in table 16.12. The main reasons for the reduction are:

- the removal of $1452 million from Ergon Energy's forecast capex
- the removal of $122 million from Ergon Energy's forecast opex
- the removal of $242 million from Ergon Energy's proposed tax allowance, reflecting in part a higher gamma than that proposed by Ergon Energy
- a lower WACC than that proposed by Ergon Energy.

[1108] Section 7 of the NEL.

Table 16.12: AER decision on Ergon Energy's annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	145.0	146.9	150.3	164.1	144.6
Return on capital[a]	694.7	782.4	867.7	956.2	1052.8
Operating expenditure[b]	360.2	387.2	396.7	400.7	397.1
Tax allowance	9.6	27.4	29.6	34.4	33.4
Capital contributions	–111.8	–115.8	–120.4	–130.7	–141.5
Revenue from shared assets	–3.2	–3.3	–3.4	–3.4	–3.5
Accelerated depreciation	10.5				
Annual revenue requirements	1105.0	1224.8	1320.5	1421.3	1482.7
Expected revenues	1123.1	1210.1	1303.9	1404.9	1513.8
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors[c] (%)	–29.61	–5.10	–5.10	–5.10	–5.10

(a) Includes equity raising costs.
(b) Includes debt raising costs, demand management incentive allowance and self insurance.
(c) Negative values for X indicate real revenue increases under the CPI–X formula.

In determining Ergon Energy's X factors, the AER (as for Energex) balanced the interest of consumers, who prefer price changes to be as smooth as possible, and the requirements of clause 6.5.9(2) of the NER. Accordingly, the AER reduced the X factor in 2012–13 to 2014–15 from –6.42 per cent to –5.10 per cent, while it reduced the X factor in 2010–11 from –39.51 per cent to –29.61 per cent. The resulting impacts in terms of retail electricity prices of the AER's decision to use these X factors, compared with Ergon Energy's proposal, is outlined in table 16.13.

Table 16.13: Retail price impacts (per cent)

	2010–11	2011–12	2012–13	2013–14	2014–15
Ergon Energy proposal					
Real impacts	14.2	1.3	1.3	1.3	1.3
Nominal impacts	15.5	2.4	2.4	2.4	2.4
AER decision					
Real impacts	10.3	0.8	0.8	0.8	0.8
Nominal impacts	11.6	1.8	1.8	1.8	1.8

Note: Calculations assume distribution network charges make up 40 per cent of retail electricity prices and 3.0 per cent demand growth per annum for the next regulatory control period. Inflation of 2.52 per cent assumed for calculating the nominal impacts.

The price impacts above exclude the effects of any annual revenue adjustments for such matters as under/over recovery of DUOS and any pass through costs. These adjustments will be accounted for as part of the annual price approval process.

16.6 AER decision

In accordance with clause 6.12.1(2)(i) of the NER, the AER refuses to approve the annual revenue requirement proposed by Energex.

In accordance with clauses 6.12.1(2)(ii) and 6.3.2(a)(4) of the NER, Energex's regulatory control period is from 1 July 2010 to 30 June 2015.

In accordance with clause 6.12.1(11) of the NER, the X factors to apply to Energex are as specified in table 16.10 of this decision.

In accordance with clause 6.3.2(a)(1) of the NER, Energex's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.10 of this decision.

In accordance with clause 6.3.2(a)(2) of the NER, an appropriate methodology for indexation of Energex's regulatory asset base is as specified in section 16.4.2 of this decision.

In accordance with clause 6.3.2(a)(5) of the NER, any other amounts, values or inputs on which Energex's building block determination is based are as specified in sections 16.4 and 16.5 of this decision.

In accordance with clause 6.12.1(2)(i) of the NER, the AER refuses to approve the annual revenue requirement proposed by Ergon Energy.

In accordance with clauses 6.12.1(2)(ii) and 6.3.2(a)(4) of the NER, Ergon Energy's regulatory control period is from 1 July 2010 to 30 June 2015.

In accordance with clause 6.12.1(11) of the NER, the X factors to apply to Ergon Energy are as specified in table 16.12 of this decision.

In accordance with clause 6.3.2(a)(1) of the NER, Ergon Energy's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.12 of this decision.

In accordance with clause 6.3.2(a)(2) of the NER, an appropriate methodology for indexation of Ergon Energy's regulatory asset base is as specified in section 16.4.3 of this decision.

In accordance with clause 6.3.2(a)(5) of the NER, any other amounts, values or inputs on which Ergon Energy's building block determination is based are as specified in sections 16.4 and 16.5 of this decision.

17 Alternative control services – street lighting

In Queensland, street lighting services are classified as alternative control services. This chapter sets out the AER's consideration of the Qld DNSPs' street lighting services control mechanism and how compliance with that mechanism is to be demonstrated by the Qld DNSPs in the next regulatory control period.

No submissions were received on this issue.

17.1 AER draft decision

Energex

The AER approved a price cap control mechanism for Energex's street lighting services for the first regulatory year of the next regulatory control period, and a price path for the remaining regulatory years of the next regulatory control period.

The price for each street lighting service contained in the draft decision was the maximum price Energex can charge for that service in a regulatory year. The price path establishes the prices for each service to be provided by Energex in the remaining regulatory years of the next regulatory control period.

Compliance with the price cap control mechanism is to be demonstrated by Energex providing, as part of its pricing proposal, the price for each street lighting service in the relevant regulatory year.[1109]

Ergon Energy

The AER approved a price cap control mechanism for Ergon Energy's street lighting services for the first regulatory year of the next regulatory control period, and a price path for the remaining regulatory years of the next regulatory control period. The AER required Ergon Energy to provide, as part of its revised regulatory proposal, a forecast capex allowance for its new street lighting assets (category 1 street lighting services) in the next regulatory control period. This allowance was to be incorporated into its limited building block model.

The AER considered its classification of *supply enhancement* and *rearrangements of network asset* services as quoted services accurately captured Ergon Energy's proposed treatment of its category 3 street lighting services.

The price for each street lighting service contained in the draft decision was the maximum price Ergon Energy can charge for that service in a regulatory year. The price path establishes the prices for each service to be provided by Ergon Energy in the remaining regulatory years of the next regulatory control period.

[1109] AER, *Draft decision, Queensland draft distribution determination 2010–11 to 2014–15*, 25 November 2009, pp. 377–399.

Compliance with the price cap control mechanism is to be demonstrated by Ergon Energy providing, as part of its pricing proposal, the price for each street lighting service in the relevant regulatory year.[1110]

17.2 Revised regulatory proposals

Energex

Energex accepted the draft decision with the exception of the application of input cost escalators. It noted that table 17.17 in the draft decision incorrectly reflected the revenue requirement included in its regulatory proposal and accordingly did not align with the revenue requirements set out in table 17.14.[1111]

Energex submitted the updated annual revenue requirement, X factors and indicative prices to reflect forecast costs included in its revised regulatory proposal, as summarised in tables 17.1 and 17.2. It stated that its updated modelling reflected the inclusion of 2008–09 actual capex in its street lighting asset base and adjustments made to standard control services that impacted on the allocation of overheads to street lights.[1112]

Table 17.1: Energex revenue requirement and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	6.7	7.6	8.6	9.6	10.7
Return on capital	9.7	10.9	12.0	13.2	14.3
Tax allowance	5.8	5.9	5.9	5.9	5.9
Opex	11.9	12.4	12.9	13.5	13.9
Adjustment for non–system revenue allocation	1.6	2.0	2.3	2.6	2.4
Annual revenue requirement[a]	35.7	38.8	41.7	44.8	47.2
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[b] (%)	17.09	–3.65	–3.65	–3.65[c]	–3.65
Smoothed annual revenue requirement	36.7	39.0	41.4	44.0	46.7

Source: Energex, *Revised regulatory proposal*, January 2010, table 9.2, p. 61.
Note: Totals may not add due to rounding.
(a) This is the unsmoothed annual revenue requirement.
(b) Negative values for X indicate real price increases under the CPI–X formula.
(c) Energex advised of an error in table 9.2 of its revised regulatory proposal. Energex, response to information request AER.EGX.RRP.02, 26 February 2010.

1110 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 379–399.
1111 Energex, *Revised regulatory proposal*, January 2010, p. 61.
1112 Energex, response to information request AER.EGX.RRP.02, 26 February 2010, confidential.

Table 17.2: Energex proposed street lighting prices (dollars per light per day, GST exclusive)

	First year price path[a] (%)	2010–11	2011–12	2012–13	2013–14	2014–15
Major non–contributed	–1.25	0.94	0.98	1.03	1.07	1.12
Major contributed	55.09	0.25	0.26	0.27	0.28	0.30
Minor non–contributed	–73.63	0.38	0.39	0.41	0.43	0.45
Minor contributed	–36.63	0.10	0.11	0.11	0.12	0.12
Price path (%)		n/a	4.47	4.47	4.47	4.47

Source: Energex, *Revised regulatory proposal*, January 2010, table 9.3, p. 62; and Energex, response to information request AER.EGX.RRP.02, 26 February 2010, confidential.
Note: A positive price path indicates a price increase.
(a) The first year price path shows the percentage change in prices between 2009–10 and 2010–11.

Ergon Energy

Ergon Energy accepted the draft decision with the following exceptions:

- the opening street lighting asset base was revised to include 2008–09 actual capex and disposals and the capex and asset disposals expected to be incurred in 2009–10 were also updated
- a forecast capex requirement of $51 million was proposed for the next regulatory control period, which included capex associated with new street lighting assets, as set out in table 17.3
- it requested the energy efficient luminaire rollout be treated as a nominated pass through event
- the application of input cost escalators.[1113]

Table 17.3: Ergon Energy forecast capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy forecast capex	9.6	10.0	10.3	10.5	10.7	51.0

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, table 20.2, p. 222.

Based on its revised regulatory proposal Ergon Energy submitted the annual revenue requirement and X factors set out in table 17.4.

[1113] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 219–223.

Table 17.4: Ergon Energy revenue requirement and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	6.3	7.0	7.7	8.4	9.2
Return on capital	7.0	7.4	7.8	8.2	8.6
Tax allowance	2.1	2.1	2.1	2.2	2.2
Opex	15.0	15.0	15.4	16.2	16.9
Annual revenue requirement[a]	30.5	31.5	33.0	35.00	36.9
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[b] (%)	–93.62	–2.71	–2.71	–2.71	–2.71
Smoothed annual revenue requirement	30.1	31.7	33.3	35.0	36.9

Source: Energex, *Revised regulatory proposal*, January 2010, table 20.3, p. 223.
Note: Totals may not add due to rounding.
(a) This is the unsmoothed annual revenue requirement.
(b) Negative values for X indicate real price increases under the CPI–X formula.

Ergon Energy advised of an error in its proposed street lighting prices set out in its revised regulatory proposal. It subsequently resubmitted the indicative prices set out in table 17.5 for the provision of its street lighting services in the next regulatory control period.[1114]

Table 17.5: Ergon Energy indicative street lighting prices (dollars per light per day, GST exclusive)

	2010–11[a]	2011–12	2012–13	2013–14	2014–15
East – Major	0.94	0.98	1.01	1.05	1.10
Price path (%)	99.69	3.96	3.99	3.97	3.97
East – Minor	0.56	0.58	0.60	0.63	0.65
Price path (%)	99.69	3.96	3.99	3.97	3.97
West – Major	0.94	0.98	1.01	1.05	1.10
Price path (%)	99.69	4.15	3.81	3.97	3.97
West – Minor	0.56	0.58	0.60	0.63	0.65
Price path (%)	99.69	4.17	3.78	3.97	3.97
Mt Isa – Major	0.94	0.98	1.01	1.05	1.10
Price path (%)	99.69	3.96	3.99	3.97	3.97
Mt Isa – Minor	0.56	0.58	0.60	0.63	0.65
Price path (%)	99.69	3.96	3.99	3.97	3.97

Source: Ergon Energy, response to information request AER.ERG.RRP.26, 10 March 2010, confidential.
Note: A positive price path indicates a price increase.
(a) The first year price path shows the percentage change in prices between 2009–10 and 2010–11.

1114 Ergon Energy, response to information request AER.ERG.RRP.26, 10 March 2010.

17.3 Issues and AER considerations

17.3.1 Energex

Opening street lighting asset base

Energex updated its 2008–09 street lighting capex, capital contributions and asset disposals in the roll forward model (RFM) to reflect actual capex undertaken in that year.[1115] Each of these adjustments affects the calculation of the opening asset value, opening tax value and remaining tax lives.

The AER reviewed Energex's 2008–09 regulatory accounts to verify the adjusted amounts and considers these adjustments are appropriate. The roll forward of Energex's street lighting asset base is shown in table 17.6.

Energex has not altered its methodology for separating non–contributed assets from contributed assets, which is based on an apportionment of assets weighted by replacement costs and the number of lights. The AER is satisfied that there is no cross–subsidisation between the two types of services. The AER therefore considers Energex's proposed opening street lighting asset base for the next regulatory control period of $97 million is appropriate.

Table 17.6: AER conclusion Energex's street lighting asset base at 1 July 2010 ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10
Opening asset base (at 1 July)	236.0	241.7	248.6	258.7	262.6
Actual capital expenditure/additions	17.4	21.3	21.4	21.4	18.2
Depreciation	–18.8	–20.3	–21.9	–23.9	–25.6
Indexation	7.0	5.9	10.5	6.4	7.6
Closing balance 30 June	241.7	248.6	258.7	262.6	262.8
Difference between actual and forecast net capex					4.9
Return on difference					2.5
Less asset value for contributed assets					–173.4
Opening street light asset base at 1 July 2010					96.8

Note: Totals may not add due to rounding.

Forecast capex and opex

Energex did not alter its forecast capex or opex allowances in its revised regulatory proposal. However, it proposed alternative input cost escalators to apply to its direct

[1115] Energex, response to information request AER.EGX.RRP.12, 16 March 2010, confidential.

control services.[1116] Energex also stated adjustments made to standard control services impact on the allocation of overheads to street lighting capex and opex.[1117]

The AER's assessment of Energex's proposed input cost escalators is set out in appendix F of this decision where the AER made a number of adjustments to the escalators proposed by Energex. The AER considers Energex should apply input cost escalators to its street lighting capex and opex consistent with appendix F. The AER's assessment of overheads is set out in chapter 7 of this decision. The AER's decision on these matters impacts on the street lighting capex and opex allowances through Energex's approved cost allocation method (CAM).[1118]

Following a request from the AER, Energex modelled its street lighting capex and opex in accordance with the revised input cost escalators and overhead rates, which resulted in a $3 million and a $1 million adjustment to its forecast capex and opex respectively. These adjustments are shown in tables 17.7 and 17.8 respectively.[1119]

Table 17.7: AER conclusion Energex's capex allowance (net of capital contributions) ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed capex	18.0	18.7	19.1	19.0	18.8	93.6
Adjustments to cost escalators	–0.8	–1.1	–0.9	–0.7	–0.5	–4.0
Adjustments to overhead allocation	0.2	0.1	0.2	0.2	0.2	0.9
Total adjustments	–0.6	–1.0	–0.8	–0.5	–0.3	–3.1
AER capex allowance	17.5	17.7	18.3	18.5	18.5	90.5

Source: Energex, response to information request, 29 April 2010, confidential.
Note: Totals may not add due to rounding.

1116 Energex, *Submission on draft determination*, February 2010, pp. 2–13.
1117 Energex, response to information request AER.EGX.RRP.02, 26 February 2010, confidential.
1118 Energex's overhead rates are calculated as a proportion of total expenditure allowances (forecast capex and opex for standard control and alternative control services). Changes to these allowances made in this decision impact the allocation of overheads to street lighting services.
1119 AER, information request, 29 April 2010.

Table 17.8: AER conclusion Energex's opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex proposed opex	11.9	12.2	12.4	12.5	12.6	61.5
Adjustments to cost escalators	–0.3	–0.3	–0.3	–0.3	–0.2	–1.4
Adjustments to overhead allocation	0.1	0.1	0.1	0.1	0.1	0.6
Total adjustments	–0.2	–0.2	–0.2	–0.1	–0.1	–0.8
AER opex allowance	11.7	11.9	12.2	12.4	12.5	60.7

Source: Energex, response to information request, 29 April 2010, confidential.
Note: Totals may not add due to rounding.
(a) This total opex adjustment includes a $20,000 decrease relating to debt raising costs.

For the reasons discussed and as a result of the AER's consideration of Energex's revised regulatory proposal and other material, the AER is not satisfied that the proposed street lighting capex and opex allowances reasonably reflect the respective capex and opex criteria, including the capex and opex objectives. The AER considers that reducing Energex's forecast capex and opex by $3 million and $1 million respectively results in street lighting capex and opex that reasonably reflects the capex and opex criteria, including the capex and opex objectives, and are the minimum adjustments necessary for these capex and opex components to comply with the NER. In coming to this view the AER has had regard to the capex and opex factors.

Other building block elements

This section sets out the AER's consideration of Energex's other building block elements: depreciation, the cost of capital, tax and adjustments for non–system revenue allocation.

The framework and approach specified that the Qld DNSPs may propose simplifying assumptions within the limited building block approach.[1120] Energex's proposed treatment of depreciation, the cost of capital and tax are consistent with its proposed approach for standard control services.

Depreciation

The AER is satisfied that Energex's allowance for depreciation for its street lighting services, as set out in table 17.9, has been determined correctly.

Cost of capital

The AER's assessment of the Qld DNSPs' proposed weighted average cost of capital (WACC) is set out in chapter 11 of this decision. In accordance with that assessment the AER applied a nominal vanilla WACC of 9.72 per cent to street lighting services for Energex. The WACC is used to calculate Energex's return on capital for street lighting services, as set out table 17.9.

[1120] AER, *Final framework and approach paper: Classification of services and control mechanism*, August 2008, p. 41.

Estimated cost of corporate income tax

The AER's assessment of the assumed utilisation of imputation credits (gamma) is set out in chapter 9 of this decision. The AER is satisfied that Energex's allowance for corporate income tax for its street lighting services, as set out in table 17.9, has been determined correctly using a gamma of 0.65 consistent with the AER's *Statement of regulatory intent* (SORI).[1121]

Adjustments for non–system revenue allocation

In the draft decision the AER accepted the inclusion of an adjustment to Energex's street lighting revenue for the non–system assets used in the provision of street lighting services. The AER notes Energex has not proposed any changes to its methodology for calculating its non–system revenue allocation. However, the amendments made to its forecast expenditure for standard control services require that the calculation of the non–system revenue allocation be updated.

Following a request from the AER, Energex modelled its non–system revenue allocation between standard control services and alternative control services in accordance with its stated approach and determined a $10.4 million adjustment to its limited building block revenue requirement, as set out in table 17.9.[1122, 1123]

Limited building block revenue requirement

Clause 6.4.3(a) of the NER sets out the building blocks that form the annual revenue requirement. The AER's limited building block approach for street lighting services incorporates the following building blocks:

- an indexed street light asset base
- depreciation
- return on capital
- forecast opex
- estimated cost of corporate income tax
- an adjustment for non–system revenue allocation.

Following a request from the AER, Energex modelled its limited building block revenue requirement for street lighting services in accordance with this decision.[1124] Table 17.9 sets out the building block elements and X factors for Energex.

[1121] AER, *Statement on the revised WACC parameters (distribution)*, *Statement of regulatory intent*, May 2009, p. 7.

[1122] Energex, response to information request, 29 April 2010, confidential.

[1123] Energex's adjustments for non–system revenue allocation result in a corresponding reduction to the standard control services revenue requirements and consequently there is no over recovery of revenues.

[1124] Energex, response to information request, 29 April 2010, confidential.

Table 17.9: AER conclusion Energex approved revenue requirement and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	6.7	7.6	8.5	9.6	10.7
Return on capital	9.4	10.6	11.7	12.8	14.0
Tax allowance	2.2	2.2	2.2	2.2	2.2
Opex	12.1	12.6	13.2	13.8	14.2
Adjustment for non–system revenue allocation	1.5	1.9	2.2	2.5	2.3
Annual revenue requirement[a]	32.0	34.8	37.8	40.9	43.4
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors[b] (%)	25.04	–3.65	–3.65	–3.65	–3.65
Smoothed annual revenue requirement	33.2	35.3	37.5	39.9	42.4

Source: Energex, response to information request, 29 April 2010, confidential.
Note: Totals may not add due to rounding.
(a) This is the unsmoothed annual revenue requirement.
(b) Negative values for X indicate real price increases under the CPI–X formula.

Prices and price path

The AER accepted Energex's methodology for determining street lighting prices in its draft decision. Taking into account the updated revenue requirement, Energex determined the prices for non–contributed and contributed major and minor street lights, as set out in table 17.10. These prices are set to recover the smoothed revenue requirement shown in table 17.9 approved by the AER.

Table 17.10: AER conclusion Energex's street lighting prices (dollars per light per day, GST exclusive)

	First year price path[a] (%)	2010–11	2011–12	2012–13	2013–14	2014–15
Major non–contributed	–11.16	0.85	0.89	0.93	0.97	1.01
Major contributed	–75.64	0.23	0.24	0.25	0.26	0.28
Minor non–contributed	39.55	0.34	0.36	0.37	0.39	0.41
Minor contributed	–41.47	0.09	0.10	0.10	0.11	0.11
Price path (%)		n/a	4.52	4.52	4.52	4.52

Source: Energex, response to information request, 29 April 2010, confidential.
Note: A positive price path indicates a price increase.
(a) The first year price path shows the percentage change in prices between 2009–10 and 2010–11.

17.3.2 Ergon Energy

Control mechanism

In the draft decision the AER considered that Ergon Energy's proposed treatment of the provision of new street lighting capex was not consistent with the AER's framework and approach and was an incorrect interpretation of the limited building block. The AER required Ergon Energy to provide a forecast capex allowance for the next regulatory control period for new street lighting assets to be incorporated into the limited building block model.[1125]

Ergon Energy restated the provision of new street lighting assets should be treated as a quoted service as set out in its regulatory proposal.[1126] It considered the build up of the actual costs of installing new street lights on an individual customer by customer basis complied with the AER's framework and approach.[1127] In developing the framework and approach the AER described that the limited building block approach applicable to the Qld DNSPs' alternative control services incorporated certain elements of the building block approach set out in Part C of NER.[1128] Ergon Energy's proposed treatment of new street lighting assets is a build up of costs on an individual customer basis which is not consistent with Part C of the NER. Accordingly, the AER is not satisfied there is sufficient reason to depart from the draft decision.

Ergon Energy proposed that if capex associated with the provision of new street lighting assets was included in the limited building block then where a non–standard street lighting asset is requested the incremental cost difference (between the standard and non–standard asset) will be charged as a quoted service. It stated a non–standard street lighting asset is one where the cost of the service is not fully recovered through prices and the incremental cost represents the uneconomic cost of the service. Ergon Energy proposed to calculate the incremental cost as the shortfall between the present value of expected charges to be paid by the customer over the life of a standard street lighting asset and the estimated cost of providing the non–standard street lighting asset.[1129]

The AER notes Ergon Energy's proposed treatment of non–standard street lighting assets is identical to that proposed by Energex—which was accepted in the draft decision. The AER recognises this is consistent with Ergon Energy's capital contributions policy approved by the QCA.[1130] On that basis, the AER accepts Ergon Energy's proposed treatment of non–standard street lighting assets.

Ergon Energy, like Energex, is required to apply its respective formula based price cap control mechanism, set out in chapter 18 of this decision, to calculate the incremental cost difference between the provision of standard and non–standard street lighting services. The AER notes that customers of these non–standard street lighting services will also be charged an ongoing maintenance charge.

[1125] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 379–380.
[1126] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 220.
[1127] Ergon Energy, *Regulatory proposal*, July 2009, p. 456.
[1128] AER, *Proposed positions, Framework and approach paper: Classification of services and control mechanism*, July 2008, pp. 50–51.
[1129] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 222.
[1130] Ergon Energy, *Regulatory proposal*, July 2010, AR047.

Opening asset base

Ergon Energy updated its street lighting asset base in the RFM to reflect actual capex and disposals in 2008–09 and updated the capex and asset disposals expected to be incurred in 2009–10.[1131] These adjustments affect the calculation of the opening asset base value, opening tax value and remaining tax lives.

The AER verified these adjustments from Ergon Energy's 2008–09 regulatory accounts and considers them appropriate. The AER also considers Ergon Energy's updated capex and asset disposals expected to be incurred in 2009–10 are reasonable. These changes have increased Ergon Energy's opening street lighting asset base from that calculated in the draft decision.

The AER's assessment of Ergon Energy's opening regulatory asset base for standard control services is set out in chapter 5 of this decision. In that assessment the AER identified and corrected an error in relation to the forecast CPI input into in the RFM. The same error was identified in the street lighting RFM and has been corrected.

The AER is therefore satisfied that the proposed opening street lighting asset base as set out in table 17.11 for the next regulatory control period of $70 million is appropriate.

Table 17.11: AER conclusion Ergon Energy's street lighting asset base at 1 July 2010 ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10
Opening asset base (at 1 July)	47.0	46.5	52.8	59.1	66.0
Actual capital expenditure/additions	2.9	10.2	9.7	11.9	9.2
Depreciation	–4.7	–5.0	–5.7	–6.4	–7.2
Indexation	1.4	1.1	2.2	1.5	1.9
Closing balance 30 June	46.5	52.9	59.1	66.0	69.9
Opening asset base at 1 July 2010					69.9

Note: Totals may not add due to rounding.

Demand forecasts

In the draft decision the AER accepted Ergon Energy's forecast demand growth for street lighting services of 2.3 per cent in each regulatory year of the next regulatory control period on the basis that this forecast was based on the average growth in customer connections over the four years to 2007–08.[1132]

The AER has since identified that the actual number of street lighting connections in Ergon Energy's regulatory accounts does not match the number of street lighting

[1131] Ergon Energy, response to information request AER.ERG.RRP.36, 21 March 2010.
[1132] AER, *Draft decision, Queensland draft distribution determination 2010–11 to 2014–15*, 25 November 2009, p. 383.

connections set out in table 144 of its regulatory proposal.[1133] The AER also found that the forecast demand growth in Ergon Energy's street lighting pricing model is inconsistent with table 145 of its regulatory proposal.

The demand growth set out in Ergon Energy's regulatory proposal exceeds the actual growth detailed in its regulatory accounts and the forecast demand growth used in its street lighting pricing model. A comparison of these demand forecasts is set out in table 17.12.

The AER sought clarification of these discrepancies from Ergon Energy.[1134] Ergon Energy stated that tables 144 and 145 of its regulatory proposal were forecasts of actual physical street lighting connections. It stated that the information set out in its regulatory accounts refers to the number of street light connections that were billed in each regulatory year. Ergon Energy added that in its street lighting pricing model it forecast the number of street lighting connections for billing purposes at the end of a regulatory (financial) year based on an extrapolation of historical data and then deduced and applied a calendar year forecast for pricing purposes.[1135]

Due to the reliance on records from its predecessor organisations Ergon Energy stated that it is unclear on the number of street lights in existence as the two separate corporate systems have widely disparate numbers. It added that it has commenced an audit of its street lighting assets and different legacy databases are being transitioned to one common platform supported by standard work processes and that it is undertaking a detailed physical stocktake through its bulk lamp replacement program.[1136] For the above reasons, the AER does not considers that the information provided in Ergon Energy's regulatory proposal is suitable for determining the forecast demand growth for street lighting services in the next regulatory control period.

To derive an appropriate demand forecast for street lighting services in the next regulatory control period the AER developed a linear estimate, set out in table 17.12. The linear estimate is derived using the actual demand growth from Ergon Energy's regulatory accounts and the forecast demand growth for 2009–10 from its street lighting pricing model.[1137]

[1133] Ergon Energy, *Regulatory proposal*, July 2009, pp. 458–459.
[1134] AER, information request AER.ERG.RRP.39, 23 March 2010.
[1135] Ergon Energy, response to information request AER.ERG.RRP.39, 29 March 2010.
[1136] Ergon Energy, response to information request AER.ERG.RRP.40, 8 April 2010.
[1137] The AER notes that the number of street lighting connections in 2009–10 in Ergon Energy's street lighting pricing model equals the number of connections set out in its distribution cost of supply model that was used to derive 2009–10 prices.

Table 17.12: AER conclusion Ergon Energy's street lighting forecast demand growth

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014-15
Regulatory proposal	120 608	123 382	126 220	129 123	132 092	135 131	138 239	141 419	144 671	147 999
Regulatory accounts	117 481	117 660	122 144	118 256	n/a	n/a	n/a	n/a	n/a	n/a
Pricing model	n/a	n/a	n/a	n/a	123 440	123 140	124 626	126 131	127 656	129 200
AER linear estimate	n/a	n/a	n/a	n/a	n/a	123 550	124 802	126 053	127 305	128 556
AER conclusion					123 440	123 140	124 626	126 131	127 656	129 200

Source: Ergon Energy, *Regulatory proposal*, July 2009, tables 144 and 145; Ergon Energy, regulatory accounts 2005–06, 2006–07, 2007–08 and 2008–09; and Ergon Energy, response to information request AER.ERG.RRP.26, PRP1004c, 16 March 2010.

The AER considers that verifiable information should be used to derive forecast demand growth where possible and that Ergon Energy's regulatory accounts meet that requirement.[1138] The QCA has required that the Qld DNSPs' regulatory reporting statements (regulatory accounts) be independently audited.[1139] The Queensland Audit Office has undertaken an assurance audit of the Qld DNSPs' regulatory accounts each year since 2001–02.

The AER's linear estimate is broadly consistent with the forecast demand growth contained in Ergon Energy's street lighting pricing model. On that basis, the AER accepts the forecast demand growth set out in Ergon Energy's street lighting pricing model.

Forecast capex

Ergon Energy proposed the forecast capex allowance set out in table 17.3. The proposed allowance is associated with replacement capex and new street lighting capex in the next regulatory control period.

Ergon Energy submitted a model that determined a forecast capex allowance for new street lighting assets based on information contained in its 2007–08 regulatory accounts.[1140] It stated that data prior to 2007–08 could not differentiate the capex gifted to Ergon Energy (via capital contributions) from that which it funded internally. Ergon Energy's model takes the customer initiated capex (from the regulatory accounts) and removes the applicable overhead rate in that regulatory year to determine a direct expenditure. The absolute change in street light connections between 2006–07 and 2007–08 is determined and multiplied by the percentage of new street lights constructed by Ergon Energy. The direct expenditure is then divided by the absolute change in street lighting connections constructed by Ergon Energy to calculate per light capex costs (in $2007–08).[1141]

1138 Ergon Energy's regulatory accounts prior to 2005–06 did not set out the number of street lighting connections.
1139 QCA, *Electricity Distribution: Regulatory Reporting Guideline*, Version 4.0, May 2005, pp. 16–17.
1140 Ergon Energy, *Revised regulatory proposal*, January 2010, RP922c.
1141 Ergon Energy, *Revised regulatory proposal*, January 2010, RP922c.

To derive its forecast capex proposal, Ergon Energy populated its model using the demand forecast set out in its regulatory proposal and the per light capex costs. That is, the number of new street lights to be constructed by Ergon Energy consistent with its forecast demand growth is multiplied by the per light capex costs to determine forecast capex in each regulatory year of the next regulatory control period. The AER notes that under this methodology, the forecast demand growth is the critical input to determining its forecast capex allowance.

As mentioned above, the AER does not consider that Ergon Energy's demand forecasts are appropriate to be applied in the next regulatory control period and if applied would result in a capex forecast inconsistent with that of a prudent operator. Accordingly, the AER's demand forecasts set out in table 17.12 should be applied to calculate Ergon Energy's forecast capex allowance for new street lighting assets in the next regulatory control period.

To avoid shortcomings in Ergon Energy's capex model which would result in a negative capex allowance in 2010–11—when demand forecasts consistent with its pricing model are applied—the AER, has provided Ergon Energy forecast capex (for 2010–11) associated with the provision of new street lighting assets equal to the average of the remaining regulatory years' forecast capex allowance.

Ergon Energy also stated that its NARMCOS model was used to determine forecast replacement capex and opex was based on 2007–08 base year data. The NARMCOS model also used forecast demand in each regulatory year of the next regulatory control period as an input. The AER notes that Ergon Energy has also input the forecast demand growth from its regulatory proposal into the NARMCOS model. For the reasons mentioned above, the AER's demand forecasts set out in table 17.12 should be input in Ergon Energy's NARMCOS model to estimate the replacement capex allowance.

The AER's assessment of Ergon Energy's proposed input cost escalators is set out in appendix F of this decision where the AER made a number of adjustments to the escalators proposed by Ergon Energy. The AER considers Ergon Energy should apply input cost escalators to its street lighting capex consistent with appendix F.

Following a request from the AER, Ergon Energy modelled its street lighting capex in accordance with the AER's revised input cost escalators, which resulted in a $2 million adjustment to its forecast capex. This is shown in table 17.13.[1142]

For the reasons discussed the AER made the following adjustments to Ergon Energy's forecast capex:

- $26 million reduction to street lighting capex to correct the forecast demand growth
- $2 million reduction to total street lighting capex, applied across all components of forecast capex, to account for the AER's approved input cost escalators.

[1142] Ergon Energy, response to information request PRP1028c, 22 April 2010.

Table 17.13: AER conclusion Ergon Energy's capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposed capex	9.6	10.0	10.3	10.5	10.7	51.1
Adjustments to demand forecasts	–4.7	–5.0	–5.2	–5.3	–5.4	–25.6
Re-inclusion of shared costs	0.0	0.1	0.1	0.1	0.0	0.3
Adjustments to cost escalators	–0.3	–0.4	–0.4	–0.4	–0.5	–2.0
Total adjustments	–5.0	–5.3	–5.5	–5.7	–5.8	–27.3
AER capex allowance	4.6	4.7	4.8	4.8	4.9	23.8

Source: Ergon Energy, response to information request PRP1028c, 22 April 2010.
Note: Totals may not add due to rounding.
The shared costs included in the deductions above should not be removed from Ergon Energy's capex allowance as the AER has not adjusted Ergon Energy's shared costs.

For the reasons discussed and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal and other material, the AER is not satisfied that Ergon Energy's street lighting capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing Ergon Energy's street lighting capex by $27 million results in street lighting capex 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.

Forecast opex

Ergon Energy did not propose to alter its forecast opex allowances in its revised regulatory proposal except for the application of input cost escalators. It proposed alternative input cost escalators to apply to its direct control services.[1143]

Ergon Energy's forecast opex allowance was calculated in its NARMCOS model and was based on the forecast number of street lighting connections in each regulatory year of the next regulatory control period. The AER notes that Ergon Energy input the forecast demand growth from its regulatory proposal into the NARMCOS model. For the reasons mentioned above, the AER's conclusion on the demand forecasts set out in table 17.12 should be input into Ergon Energy's NARMCOS model to estimate its opex allowance. This results in a $6 million dollar reduction to Ergon Energy's forecast opex.[1144]

The AER's assessment of Ergon Energy's proposed input cost escalators is set out in appendix F of this decision where the AER made a number of adjustments to the escalators proposed by Ergon Energy. The AER considers that Ergon Energy should apply input cost escalators to its street lighting opex consistent with appendix F.

[1143] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 221.
[1144] Ergon Energy, response to information request PRP1028c, 22 April 2010.

Following a request from the AER, Ergon Energy modelled its street lighting opex in accordance with the revised input cost escalators, which resulted in a $2 million adjustment to its forecast opex.[1145] These adjustments are shown in table 17.14.

For the reasons discussed the AER made the following adjustments to Ergon Energy's forecast opex:

- $6 million reduction to correct the forecast demand growth input into the NARMCOS model
- $2 million reduction to account for of the AER's approved input cost escalators.

For the reasons discussed and as a result of the AER's consideration of Ergon Energy's revised regulatory proposal and other material, the AER is not satisfied that Ergon Energy's street lighting opex reasonably reflect the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's street lighting opex by $6 million results in street lighting opex 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 17.14: AER conclusion Ergon Energy's opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposed opex	14.6	14.3	14.3	14.7	15.0	72.9
Adjustments to demand forecasts	–0.9	–1.1	–1.2	–1.3	–1.5	–6.0
Re-inclusion of shared costs	0.2	0.4	0.3	0.3	0.3	1.5
Adjustments to cost escalators	–0.2	–0.3	–0.4	–0.4	–0.5	–1.8
Total adjustments	–1.0	–1.0	–1.2	–1.5	–1.6	–6.3
AER opex allowance	13.7	13.3	13.1	13.2	13.3	66.6

Source: Ergon Energy, response to information request PRP1028c, 22 April 2010.
Note: Totals may not add due to rounding.
The shared costs included in the deductions above should not be removed from Ergon Energy's opex allowance as the AER has not adjusted Ergon Energy's shared costs.

Other building block elements

This section sets out the AER's consideration of Ergon Energy's other building block elements: depreciation, the cost of capital, tax and pass throughs.

The framework and approach specified that the Qld DNSPs may propose simplifying assumptions within the limited building block approach.[1146] Ergon Energy's proposed

[1145] Ergon Energy, response to information request PRP1028c, 22 April 2010.
[1146] AER, *Final framework and approach paper: Classification of services and control mechanism*, August 2008, p. 41.

treatment of tax, depreciation, cost of capital and pass through for street lighting services are consistent with its proposed approach for standard control services.

Depreciation

The AER is satisfied that Ergon Energy's allowance for depreciation for its street lighting services, as set out in table 17.15, has been determined correctly.

Cost of capital

Ergon Energy proposed to apply the nominal vanilla WACC of 10.06 per cent proposed for standard control services to street lighting services.[1147] The AER's assessment of the Qld DNSPs' proposed WACC is set out in chapter 11 of this decision. In accordance with that assessment the AER has applied a nominal vanilla WACC of 9.72 per cent to street lighting services. This WACC has been used to calculate Ergon Energy's return on capital for street lighting services, as set out in table 17.15.

Estimated cost of corporate income tax

The AER's assessment of the assumed utilisation of imputation credits (gamma) is set out in chapter 9 of this decision. The AER is satisfied that Ergon Energy's allowance for corporate income tax for its street lighting services, as set out in table 17.15, has been determined correctly using a gamma of 0.65 consistent with the SORI.[1148]

Pass through arrangements

Ergon Energy submitted that the energy efficient street lighting rollout be included as a specific nominated pass through event.[1149] The AER's assessment of the Qld DNSPs' proposed pass through events is set out in chapter 15 of this decision. The AER considers it is appropriate to apply pass through provisions to alternative control services.[1150] Therefore, the events accepted in chapter 15 of this decision will apply to all direct control services, including street lighting services.

Limited building block revenue requirement

Clause 6.4.3(a) of the NER sets out the building blocks that form the annual revenue requirement. The AER's limited building block approach for street lighting services incorporates the following building blocks:

- an indexed street light asset base
- depreciation
- return on capital
- forecast opex

[1147] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 221.
[1148] AER, *Statement on the revised WACC parameters (distribution)*, *Statement of regulatory intent*, May 2009, p. 7.
[1149] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 221.
[1150] AER, *Final framework and approach paper: Application of schemes – Energex and Ergon Energy 2010–15*, November 2008, p. 56.

- estimated cost of corporate income tax.

The AER modelled Ergon Energy's limited building block revenue requirement for street lighting services in accordance with this decision using the PTRM. Table 17.15 sets out the building block elements for Ergon Energy.

Table 17.15: AER conclusion Ergon Energy's approved revenue requirement ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	6.3	6.8	7.3	7.9	8.4
Return on capital	6.8	6.7	6.5	6.3	6.1
Opex	14.0	14.0	14.1	14.6	15.1
Tax allowance	0.8	0.8	0.8	0.8	0.8
Annual revenue requirement[a]	27.9	28.3	28.7	29.6	30.5
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors[b] (%)	–73.99	–1.00	–1.00	–1.00	–1.00
Smoothed annual revenue requirement	27.1	28.0	29.0	30.0	31.1

Note: Totals may not add due to rounding.
(a) This is the smoothed annual revenue requirement.
(b) A negative X factor indicates a price increase.

Prices and price path

It was not possible for the AER, in the draft decision, to evaluate the underlying methodology Ergon Energy employed to derive the prices set out in the draft decision as its methodology was only provided in late November 2009 in response to a request from the AER.[1151] However, the AER has assessed Ergon Energy's proposed street lighting pricing methodology in this decision.

In its revised regulatory proposal Ergon Energy submitted a model that translates the annual limited building block revenue requirement, calculated in the PTRM, into prices for street lighting services in the next regulatory control period. It subsequently advised that it had identified an error in that methodology and resubmitted its indicative prices and its pricing model. Ergon Energy stated that a correction was necessary as the initial model disproportionately allocated revenue between major and minor asset types, resulting in an over recovery of costs from minor street lights and an under recovery of costs from major street lights. Ergon Energy stated that modifications made in the resubmitted model resolved the error.[1152] Ergon Energy's resubmitted prices are set out in table 17.5.

[1151] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 397–398.
[1152] Ergon Energy, response to information request AER.ERG.RRP.26, 10 March 2010.

The AER reviewed Ergon Energy's resubmitted pricing methodology. In each regulatory year of the next regulatory control period, Ergon Energy disaggregates the forecast number of street light connections according to region (East, West, Mt Isa) and type (major or minor). The major and minor unit rates for the relevant regulatory year are then multiplied by the number of connections in each region. The resulting asset values are then converted into percentages determining a whole of network asset split. These percentages are used to allocate the limited building block revenue requirement. The resulting revenue proportions are divided by the number of forecast street lighting connections to be billed in each region and then divided by the average number of days in a regulatory year to derive a per day per light price for each asset type in each region.[1153] The AER considers this a reasonable approach and is satisfied that Ergon Energy's resubmitted pricing model applies its methodology correctly.

The AER sought additional information from Ergon Energy regarding its 2009–10 prices for street lighting services and their relationship to the 2010–11 prices. Ergon Energy stated that it is not possible to directly compare the 2009–10 prices in its network tariff guide with the 2010–11 prices.[1154] In particular, it stated that in the current regulatory control period prices are calculated as a share of the entire revenue cap and therefore the allocation of revenue is impacted by other customers within the pricing model whereas in 2010–11, prices will be calculated from an amount of revenue derived solely from the provision of street lighting services. It further noted that its 2009–10 prices are derived from its distribution cost of supply model which allocates cost components of the aggregate annual revenue requirements based on one or more identified allocators.[1155]

Overall, the AER understands the differences in pricing in 2009–10 and the first regulatory year of the next regulatory control period (2010–11) to be the result of the methodology adopted in the current regulatory control period to allocate the aggregate annual revenue requirement to derive street lighting prices. Street lighting prices in the next regulatory control period are set to recover the annual revenue requirement approved in this decision. The AER's review of Ergon Energy's limited building block revenue requirements results in the proposed P_0 adjustment reducing from 93.62 per cent to 73.99 per cent. The price path to apply to prices from the second regulatory year of the next regulatory control period (2011–12) is set out in table 17.16.

Following a request from the AER, Ergon Energy modelled its limited building block revenue requirement for street lighting services to reflect the changes made by the AER and determined the major and minor street lighting prices set out in table 17.16. These prices are set to recover the smoothed revenue requirement approved by the AER.

[1153] Ergon Energy street lighting pricing model applies an average of 365.25 days per calendar year.
[1154] Ergon Energy, *Network Use of System Tariff Guide 2009–2010*, 20 November 2009.
[1155] Ergon Energy, response to information request AER.ERG.RRP.26, 10 March 2010.

Table 17.16: AER conclusion Ergon Energy's street lighting prices (dollars per light per day, GST exclusive)

	2010–11[a]	2011–12	2012–13	2013–14	2014–15
East – major	0.84	0.86	0.88	0.90	0.93
Price path (%)	79.69	2.30	2.32	2.31	2.31
East – minor	0.50	0.51	0.53	0.54	0.55
Price path (%)	79.69	2.30	2.32	2.31	2.31
West – major	0.84	0.87	0.88	0.90	0.93
Price path (%)	79.69	2.48	2.14	2.31	2.31
West – minor	0.50	0.52	0.53	0.54	0.55
Price path (%)	79.69	2.50	2.12	2.31	2.31
Mt Isa – major	0.84	0.86	0.88	0.90	0.93
Price path (%)	79.69	2.30	2.32	2.31	2.31
Mt Isa – minor	0.50	0.51	0.53	0.54	0.55
Price path (%)	79.69	2.30	2.32	2.31	2.31

Source: Ergon Energy, response to information request, 6 May 2010.
Note: A positive price path indicates a price increase.
(a) The first year price path shows the percentage change in prices between 2009–10 and 2010–11.

17.3.3 Demonstration of compliance with the price cap

Clause 6.12.1(13) of the NER requires that the AER's distribution determination include a decision on how compliance with the control mechanism for street lighting services is to be demonstrated.

Under the price cap control mechanism the price for each street lighting service contained in this decision is the maximum price the Qld DNSPs can charge for that service in a regulatory year. Compliance with the control mechanism is to be demonstrated by the Qld DNSPs providing, as part of their annual pricing proposals, the proposed prices for each street lighting service in the relevant regulatory year.

The proposed prices must be consistent with this decision for the relevant regulatory year. The pricing proposal should also include the revenues collected from the provision of each service in the preceding regulatory year.

17.4 AER conclusion

The approved revenue requirements for each of the Qld DNSPs' street lighting services are set out in tables 17.9 and 17.15. The prices for the Qld DNSPs' respective street lighting services are set to recover the approved revenue requirements. The results of this process are set out in tables 17.10 and 17.16.

The 2010–11 price for each of the Qld DNSPs respective street lighting services, set out in tables 17.10 and 17.16, represents the maximum price for each service to be provided by the Qld DNSPs in that year. The price paths, set out in tables 17.10 and 17.16, establish the prices for each street lighting service to be provided by the Qld DNSPs in the remaining regulatory years of the next regulatory control period.

Compliance with the price cap control mechanism is to be demonstrated by each Qld DNSP providing, as part of its pricing proposal, the price for each street lighting service in the relevant regulatory year consistent with this decision.

The AER's approved prices represent the maximum price to be charged for each street lighting service in each regulatory year of the next regulatory control period.

17.5 AER decision

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Energex's street lighting services is:

- caps on the prices of individual services, in the first regulatory year of the next regulatory control period (as set out in table 17.10 of this decision)
- price paths, as set out in table 17.10 of this decision, for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(13) of the NER, Energex's compliance with the control mechanism for street lighting services is to be demonstrated through the annual pricing approval process. The process for demonstrating compliance is specified in section 17.3.3 of this decision.

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Ergon Energy's street lighting services is:

- caps on the prices of individual services in the first regulatory year of the next regulatory control period (as set out in table 17.16 of this decision)
- price paths, as set out in table 17.16 of this decision, for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(13) of the NER, Ergon Energy's compliance with the control mechanism for street lighting services is to be demonstrated through the annual pricing approval process. The process for demonstrating compliance is specified in section 17.3.3 of this decision.

18 Alternative control services – quoted and fee based services

In Queensland, quoted and fee based services are classified as alternative control services. This chapter sets out the AER's consideration of the Qld DNSPs' quoted and fee based services control mechanism and how compliance with that mechanism is to be demonstrated by the Qld DNSPs in the next regulatory control period.

No submissions were received on this issue.

18.1 AER draft decision

The AER approved the formula proposed by Energex to derive the prices for quoted and fee based services after an amendment to remove the profit margin component.

The AER approved the formula proposed by Ergon Energy to derive the prices for quoted and fee based services after an amendment to remove the 'other costs' component.

For quoted services, the AER determined the capped price of providing the illustrative configuration of each individual quoted services in the first regulatory year of the next regulatory control period. The AER also established a price path for each individual formula component. The AER stated compliance with the price cap control mechanism was to be demonstrated by the Qld DNSPs providing, as part of their pricing proposals, the capped price and calculation for each illustrative configuration of each individual quoted service in the relevant regulatory year.

For fee based services, the AER determined a capped price for individual services for the first regulatory year of the next regulatory control period and established a price path for each service. The AER stated compliance with the price cap control mechanism was to be demonstrated by the Qld DNSPs providing, as part of their pricing proposals, the capped price for each individual fee based service in the relevant regulatory year.

18.2 Revised regulatory proposals

Energex

Energex accepted the draft decision with the exception of the following aspects:[1156]

- the removal of the profit margin formula component
- the AER's application of input cost escalators, on costs and overhead rates.

Energex also provided updated information the AER requested in the draft decision relating to the customer connections employee classification and the capital allowance.

[1156] Energex, *Revised regulatory proposal*, January 2010, pp. 54–60.

Ergon Energy

Ergon Energy accepted the draft decision with the exception of the following aspects:[1157]

- the removal of the ‘other costs’ formula component
- the forecast labour on cost rate
- the AER’s application of input cost escalators and overhead rates.

Ergon Energy also provided updated information the AER requested in the draft decision relating to: the contractor, system operator and trainee employee classifications, allocation of employee classifications in its illustrative examples and the capital allowance.

Ergon Energy sought clarification on the volume and revenue reporting requirements for demonstrating compliance with the price cap control mechanism.

18.3 Issues and AER considerations

18.3.1 Control mechanism

The AER’s framework and approach paper stated that it would apply a formula based approach (a non-building block approach) to determine the efficient costs of providing quoted and fee based services. The approach involves a price cap control mechanism in the first regulatory year of the next regulatory control period and a price path for the remaining regulatory years of that period.[1158] A price cap form of control is currently applied to these services by the QCA.[1159]

Quoted services

The AER recognises that the scope of the work for each quoted service is not known prior to the service being undertaken and therefore these services are provided on a price on application basis. Hence, it is not possible to cap the price for individual quoted services as the scope of work, and therefore the cost, for each individual service is not known prior to the service being provided. The Qld DNSPs’ proposed formulas account for this variability.

Given the nature of quoted services, the application of the price cap control mechanism in this instance requires the individual formula components to be capped. This approach allows the total price for each quoted service to vary according to the size, scale and scope of the individual service being undertaken. For subsequent regulatory years, the AER has specified a price path for each formula component to be used to derive the price of individual quoted services.

[1157] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 226–234.

[1158] AER, *Final framework and approach paper: Classification of services and control mechanisms*, August 2008, pp. 43–44.

[1159] The QCA approved the application of the formula for quoted services and approves the prices for fee based services on an annual basis as part of its pricing principles statement. The Qld DNSPs set out a formula identifying all the variables for each quoted service and what variables are subject to change.

Appendix I and J (confidential) of this decision sets out illustrative worked examples of each quoted service to be offered by the Qld DNSPs in the next regulatory control period.

Fee based services

The formula based price cap control mechanism is also to be applied to derive the price for each fee based service. The capped price is calculated using the individual formula components used in the provision of each service. Given that the size, scale and scope of each fee based service is known in advance of each individual service being requested, the AER has capped the prices for the first regulatory year. For subsequent regulatory years, the AER has specified a price path for each formula component to be used to derive the price of individual fee based services.

The AER has determined the efficient costs for fee based services in the next regulatory control period, which are set out in appendix K of this decision.

18.3.2 Application of input cost escalators, on costs and overhead rates

In the draft decision the AER capped the price of each individual quoted and fee based service in the first regulatory year of the next regulatory control period and established a price path for each individual formula component. To establish the individual price paths the AER applied the respective labour (internal and external) and material cost escalators applied to the Qld DNSPs' standard control services, and derived on cost and overhead rates based on forecast direct expenditure in the next regulatory control period. The AER considered that fixing the price path for each formula component provided both the Qld DNSPs and their customers with certainty.[1160]

In its revised regulatory proposal, Energex stated that the application of fixed escalation rates for materials and external labour rates imposed an unreasonable administrative burden. It submitted that materials and external labour are procured through competitive tender processes. Energex also considered that the draft decision overrides its governance arrangements (thereby requiring duplication of its corporate systems) and may also result in prices that do not reflect underlying costs.[1161]

Energex stated that on cost and overhead rates are derived in accordance with its Cost Allocation Method (CAM) and will be updated annually according to the actual direct expenditure (capex and opex) incurred. It stated that the application of fixed on cost and overhead rates impose additional administrative costs to adjust estimates and invoices manually which is inefficient.[1162]

Energex considered the approach to input cost escalators, on costs and overhead rates set out in the draft decision was unnecessary. To address the AER's concerns it stated

[1160] AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, pp. 409–411, 417.
[1161] Energex, *Revised regulatory proposal*, January 2010, pp. 56–57.
[1162] Energex, *Revised regulatory proposal*, January 2010, p. 58.

that quoted services prices could be subject to scrutiny as part of the annual pricing proposal.[1163]

Ergon Energy stated that under the QCA's current approach materials are a direct pass through such that customers see actual costs at the time the service is implemented and that under the AER's approach it will be exposed to actual movements in materials costs. Ergon Energy submitted that the current approach should be adopted in the distribution determination.[1164]

Ergon Energy also stated that it calculates its overhead rate annually in accordance with its CAM and fixing overhead rates means that quoted and fee based services prices will not reflect the actual overhead rates.[1165]

The intent of the draft decision was to fix input cost escalators, on cost and overhead rates to provide certainty to both the Qld DNSPs and their customers and minimise ongoing reporting and compliance requirements. The AER recognises that this imposition could detract from the cost reflectivity of quoted and fee based service prices under the price cap control mechanisms and adversely affect the Qld DNSPs' administrative and governance processes and procedures. The AER considers that such an outcome is undesirable.

The AER therefore considers it appropriate to include greater flexibility in the application of input cost escalators, on cost and overhead rates within the formula based price cap control mechanisms for quoted and fee based services. However, to ensure transparency in the price setting process, it is therefore necessary to include additional compliance and reporting requirements. The requirements are set out in section 18.3.5.

The prices for the Qld DNSPs' illustrative quoted service examples and fee based services set out in appendices I, J and K respectively are indicative only.

18.3.3 Assessment of control mechanism components

The AER has established a price path for each formula component to be used to derive the price of individual quoted and fee based services in each year of the next regulatory control period.

18.3.3.1 Labour rates

First regulatory year rates

Energex

Energex developed its proposed fee based services using its customer connections employee classification. These rates were determined based on the forecast total labour costs and hours incurred in the provision of fee based services in 2008–09 escalated by the labour cost escalator.

[1163] Energex, *Revised regulatory proposal*, January 2010, p. 59.
[1164] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 228.
[1165] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 230.

In the draft decision the AER considered Energex's approach was reasonable as it reflected actual costs incurred in providing fee based services. However, the actual values for 2008–09 were not available when Energex submitted its regulatory proposal. Accordingly, the AER required Energex to provide actual total costs and hours incurred as part of its revised regulatory proposal.[1166]

Energex provided this updated information in its revised regulatory proposal, which the AER considers is appropriate. The AER has applied information provided Energex to determine its 2008–09 base labour rates (ordinary and overtime) for the customer connections employee classification.

Ergon Energy

In the draft decision the AER approved the 2008–09 base labour rates previously accepted by the QCA, which did not include three additional employee classifications (contractor, system operator and trainee) proposed by Ergon Energy.[1167]

In its revised regulatory proposal Ergon Energy provided further information about its contractor, system operator and trainee employee classifications. It stated that:

- the contractor employee classification is not used in the provision of quoted and fee based services and therefore does not require a base labour rate.
- the control room employee classification, accepted by the QCA, was renamed as the system operator employee classification and therefore does not require a base labour rate.
- it is appropriate to apply the apprentice's employee classification base labour rate to trainees as this was previous practice in 2006–07 and 2007–08 and therefore an additional base labour rate is not required.[1168]

Ergon Energy stated that the base labour rate for the trainee employee classifications would surpass the apprentices' employee classification base labour rate from 2008–09 onwards.[1169] The AER considers it reasonable to apply the apprentices' employee classification base labour rate to trainees.

Based on the additional information provided by Ergon Energy, the AER accepts that it is not necessary to include the three additional employee classifications and that the employee classifications included in the draft decision are sufficient to derive the prices for quoted and fee based services in the next regulatory control period.

The AER also required Ergon Energy to provide information that demonstrates how each employee classification has been applied in its illustrative quoted service examples.

[1166] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 406.
[1167] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 407.
[1168] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 226.
[1169] Ergon Energy, *Regulatory proposal*, July 2009, pp. 506–508.

Ergon Energy stated that it had correctly allocated its employee classifications and provided supporting information in its revised regulatory proposal.[1170]

The AER sought a number of clarifications from Ergon Energy with respect to the composition of its illustrative quoted service configurations.[1171] On the basis of information provided the AER is satisfied that the composition of Ergon Energy's illustrative quoted service configurations correctly applies, and appropriately allocates, each employee classifications to the type of skills required to undertake each individual service.

Price path

The AER's assessment of the Qld DNSPs' proposed labour cost escalators is contained in appendix F of this decision. The AER considers it appropriate to apply its labour cost escalators, set out in table 18.1, to the Qld DNSPs base labour rates to establish a capped price for each employee classification in the first regulatory year of the next regulatory control period and to establish a price path for the remaining regulatory years of that period.

Table 18.1: AER's nominal price path for the Qld DNSPs labour formula components (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Energex						
Labour	5.29	2.70	3.63	3.81	4.06	4.17
Contractor services	4.00	3.35	3.55	3.75	4.04	4.15
Ergon Energy						
Labour	4.89	2.71	3.52	3.72	4.03	4.14

For the reasons discussed in section 18.3.2, the Qld DNSPs' internal labour and Energex's contractor services (external labour) cost escalators set out in table 18.1 are not a binding cap on the Qld DNSPs in the next regulatory control period. The AER requires the Qld DNSPs to calculate their respective internal and external labour cost escalators for each regulatory year of the next regulatory control period and provide both qualitative and quantitative supporting information to the AER as part of their annual pricing proposals.

Following a request from the AER, the Qld DNSPs modelled each of their respective illustrative quoted service configurations and fee based services prices set out in appendices I, J (confidential) and K in accordance with the labour cost escalators in table 18.1.

1170 Ergon Energy, *Revised regulatory proposal*, January 2010, attachments RP920c, RP921c, RP923c, RP924c, RP925c and RP926c.
1171 AER, information request AER.ERG.RRP.41, 19 April 2010.

18.3.3.2 Materials

The materials component is not used in the provision of the Qld DNSPs' fee based services.

The AER's assessment of the Qld DNSP's proposed material cost escalators is contained in appendix F of this decision. Following a request from the AER, the Qld DNSPs modelled each of their respective illustrative quoted service configurations set out in appendices I and J (confidential) in accordance with these material cost escalators.

For the reasons discussed in section 18.3.2, the material cost escalators set out in appendix F do not represent a binding cap on the potential escalation of materials to be used in the provision of quoted services in the next regulatory control period.

18.3.3.3 Capital allowance

The capital allowance is a charge applied to reflect the use of non–system physical assets owned by the Qld DNSPs, involved in the delivery of quoted and fee based services.

Energex

In the draft decision the AER considered the approach undertaken and the data used by Energex to calculate its general capital allowance was reasonable as it reflected forecast non–system assets used in the provision of quoted and fee based services in the next regulatory control period. The AER required Energex to update its general capital allowance to reflect the forecasts included in the AER's decision.[1172]

Energex recalculated its general capital allowance as part of its revised regulatory proposal and stated that the adjustment had a negligible effect on the allowance.[1173]

Following a request from the AER, Energex modelled its general capital allowance on the basis of the expenditure allowances provided in this decision. Table 18.2 sets out the AER's approved indicative capital allowance.

Table 18.2: AER's nominal capital allowance for Energex's quoted and fee based services (dollar per dollar of labour expenditure) – confidential

	2010–11	2011–12	2012–13	2013–14	2014–15
Capital allowance (general)					

Source: Energex, response to information request, 29 April 2010, confidential.

Ergon Energy

In the draft decision the AER did not accept Ergon Energy's proposed capital allowances for non–system assets and vehicles as information substantiating these figures was not provided.[1174]

1172 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 412.
1173 Energex, *Revised regulatory proposal*, January 2010, p. 57.
1174 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 413–414.

Ergon Energy stated that it had inadvertently not included the calculation of its proposed capital allowances in response to an AER information request and subsequently provided this information as attachment RP928c of its revised regulatory proposal.[1175]

Capital allowance—non–system assets

Ergon Energy proposed to apply a percentage to its direct costs (labour, materials and 'other costs') as representing its non–system capital allowance.

The AER notes that Ergon Energy's proposed capital allowance of [redacted] is higher than the [redacted] proposed in its regulatory proposal and this difference is not explained in its revised regulatory proposal.

The key consideration for the AER is the reasonableness of the proposed non–system capital allowance (recovered as a percentage).

To derive its non–system capital allowance Ergon Energy undertook the following steps:

- Allocated a capital allowance dollar amount for each quoted and fee based service
- Determined this dollar amount as a percentage of the total direct cost for each quoted and fee based service. This was undertaken for urban/short rural and long rural/isolated priced fee based services and quoted services in both 2008–09 and 2009–10
- These resulting percentages for each category of services in a particular regulatory year (for example, 2008–09 urban/short rural fee based services) were averaged
- The resulting averages for fee based services (urban/short rural fee based services and long rural/isolated fee based services) in a particular regulatory year were then averaged
- The resulting category averages (2008–09 fee based services, 2008–09 quoted services, 2009–10 fee based services and 2009–10 quoted services) were then averaged to determine the proposed [redacted] non–system capital allowance.

Ergon Energy's method of averaging averages of averages is analytically weak.

Ergon Energy has not provided any information supporting a link between the capital allowance in 2008–09 and 2009–10 and the provision of quoted and fee based services in those regulatory years. In the absence of such information or other explanations showing that the revenues recovered from the provision of quoted and fee based services it is not possible to determine if this (notwithstanding the weak methodology) is reflective of the actual use of non–system assets.

It appears that Ergon Energy has developed its non–system capital allowance without any consideration of the outturn volume of jobs undertaken, total expenditure or

[1175] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 228–229 and attachment 928c (confidential).

labour hours incurred in 2008–09 or 2009–10. The AER considers that this methodology as well as being analytically weak has no relationship to actual outcomes and thus could yield misleading results if it were applied in the next regulatory control period.[1176]

Overall, the AER is not satisfied that Ergon Energy's proposed methodology is robust or is reflective of the provision of quoted and fee based services in the next regulatory control period. Therefore, the AER considers it necessary to apply an alternative methodology to calculate a capital allowance for quoted and fee based services.

Capital allowance—vehicles

The AER has considered a number of alternatives to established a capital allowance for Ergon Energy

Ergon Energy stated that it had corrected an error in the calculation of remaining asset lives. Ergon Energy stated that it calculates base depreciation rates by grouping each fleet vehicle into vehicles classes. Costs are calculated from its finance systems for each vehicles class and are then divided by the estimated total hours of use to derive an hourly rate. It submitted that this methodology was used in 2008–09 and accepted by the QCA. Ergon Energy stated that in 2009–10 it refined vehicle classes, updating vehicle data and available hours before preparing it 2009–10 vehicle rates.[1177]

The AER has identified a number of concerns with Ergon Energy's methodology.

The vehicles capital allowance (dollars per hour) consists of two components: a depreciation allowance (the return of capital) and a return on asset (the return on capital).

In the draft decision the AER noted that Ergon Energy did not demonstrate how the proposed base depreciation rates were calculated.[1178] The depreciation allowance component for different vehicle classes used by Ergon Energy is an input in 2008–09 and 2009–10. Ergon Energy's has not provided any information that demonstrates how each vehicle classes base depreciation rates was determined.

Further, the AER notes that the base depreciation rates for 2009–10 in attachment RP919c do not reconcile with those provided to the QCA in that year. The AER notes that this may be attributable to the refinements Ergon Energy has made to its vehicles classes but if this is the case as it has not been described.

The return on assets component equals the depreciation allowance divided by the standard asset life multiplied by the weighted average cost of capital and as such is dependent on the depreciation allowance.

It is therefore unclear how the base depreciation rates were calculated or how Ergon Energy applied its methodology (what volume and composition of jobs and hours were forecast in 2008–09). Further, in each year of the next regulatory control period,

[1176] In these circumstances, the AER also considers that adherence to this methodology would also be inconsistent with the national electricity objective in section 7 of the NEL.

[1177] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 229.

[1178] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 414.

the base depreciation allowances were escalated by the vehicles cost escalator. The AER is not satisfied that Ergon Energy has demonstrated that there is a tangible link between the vehicle capital allowance in 2008–09 or 2009–10 and the provision of quoted and fee based services in the next regulatory control period.

Ergon Energy has not responded to the concerns raised in the draft decision in relation to the calculation of base depreciation rates. The AER has not been provided with sufficient information to substantiate Ergon Energy's proposed vehicles capital allowance, and has therefore been unable to assess its efficiency. On that basis, the AER does not consider it appropriate to accept Ergon Energy's proposed vehicles capital allowance. In the absence of sufficient information the AER considers it necessary to apply an alternative methodology to calculate a capital allowance for quoted and fee based services.

AER capital allowance
Chapter 16 of this decision sets out Ergon Energy's annual revenue requirements for standard control services, calculated using the post–tax revenue model. Ergon Energy included an adjustment for the expected use of shared assets for unregulated and alternative control services during the next regulatory control period. This adjustment is deducted from the annual revenue requirement for standard control services and is set out in table 18.3.

Table 18.3: Ergon Energy's revenue from shared assets ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Revenue from shared assets	3.2	3.3	3.4	3.5	3.5

The AER requested that Ergon Energy provide the underlying forecasts that recover these revenue amounts from shared assets used in the provision of unregulated and alternative control services in each regulatory year of the next regulatory control period.[1179]

In response, Ergon Energy stated that it was not possible to forecast expected revenues, volumes or labour hours associated with the provision of quoted and fee based services with any certainty due to the inclusion of the design and construction of new large customer connection assets as a quoted service. Given this uncertainty, it was not possible to allocate a fixed amount of return on capital and depreciation associated with non-system assets across the various alternative control services and therefore it was not able to provide the underlying forecasts that recover the shared asset adjustment made to standard control services.[1180]

Ergon Energy, however, advised that the shared asset adjustments in 2007–08 and 2008–09 were based on allocated asset values from schedule R of its regulatory

[1179] AER, information request AER.ERG.RRP.41, 19 April 2010 and AER, information request AER.ERG.RRP.42, 27 April 2010.
[1180] Ergon Energy, response to information request AER.ERG.RRP.41, 22 April 2010.

accounts. This historical data was used as the basis to determine the shared asset adjustments set out in table 18.3.[1181]

The AER notes that the shared asset adjustments in 2007–08 and 2008–09 did not include street lighting services or the design and construction of new large connections assets service and that quoted and fee based services do not completely align with excluded distribution services. However, in the absence of any robust methodology or suitable forecasts the AER considers that Ergon Energy's regulatory accounts provide the best available information from which to derive a capital allowance. Ergon Energy's regulatory accounts do not separate the return on and return of capital recovered from non–system assets from that recovered from vehicles, that is, the return on and return of is shown in aggregate. Using the information in schedule R of Ergon Energy's regulatory accounts the AER has determined a capital allowance of [redacted], as set out in table 18.4, which represents depreciation and the return on capital as a proportion of revenue recovered from excluded distribution services in 2007–08 and 2008–09.

The AER considers the capital allowance, based on Ergon Energy's regulatory accounts, while incorporating the best available information has a number of shortcomings mentioned above and therefore is not appropriate to apply. The AER is also concerned that this allowance would not recover an appropriate return on and return of capital associated with the use of non–system assets.

Table 18.4: AER conclusion Ergon Energy's capital allowance (nominal) – confidential

	2007–08	2008–09	average
Opex			
Depreciation			
Return on capital			
Total			
Capital allowance (percentage of direct expenditure)			

In the absence of a robust methodology, forecast data or appropriate historical information the AER will apply the average of Energex's general capital allowance to Ergon Energy, that is, [redacted]. The AER considers this is reasonable as the classification of the Qld DNSPs quoted and fee based services is identical and the provision of these services essentially utilises the same non–system assets. The AER accepted Energex's proposed methodology for calculating its general capital allowance as part of the draft decision.

1181 Ergon Energy, response to information request AER.ERG.RRP.42, 29 April 2010.

Ergon Energy is to apply this capital allowance to its total direct expenditure (labour and materials). The AER has adjusted Ergon Energy's price cap control mechanism formula in section 18.4 to account for this adjustment.

In chapter 4 of this decision the AER noted that differences between the expected and actual use of shared assets will be accounted for by an annual adjustment to Ergon Energy's maximum allowed revenue via the *transitional* variable in the revenue cap control mechanism formula.

The inclusion of the *transitional* variable in the revenue cap control mechanism provides an effective unders and overs mechanism for revenue recovered from shared assets. This provides assurance that if the demand for quoted and fee based services varies significantly, Ergon Energy will earn revenues commensurate with the provision of quoted and fee based services whilst neither under nor over recovering revenues from the provision of standard control services. .

Ergon Energy is not required to recalculate its non–system capital allowance in the next regulatory control period. The illustrative quoted service examples and fee based services set out in appendix I, J and K were calculated using the AER's approved capital allowance.

18.3.3.4 On costs and overheads

The AER accepted the Qld DNSPs' methodologies for calculating overhead rates in the draft decision.

Energex

In the draft decision the AER did not accept Energex's proposed labour on cost rate as there was insufficient information that demonstrated its calculation and therefore the AER was unable to assess its efficiency.[1182]

The imposition of the benchmark labour on cost rate restricts the calculation of the labour on cost rate in each regulatory year of the next regulatory control period and results in an inconsistency between the calculation of labour on cost rates and fleet and material on cost rates. The AER views this outcome as undesirable. Although Energex has not provided information that supports the calculation of its labour on cost rate the AER does not consider it appropriate to impose the benchmark labour on cost rate determined in the draft decision.

Energex's labour, fleet and materials on cost rates are based on forecast direct expenditure (capex and opex). In the draft decision the AER considered the forecasts used to calculate Energex's fleet and materials on cost rates were reasonable. Energex's CAM sets out a method for determining on cost rates.[1183]

The AER requires that Energex calculate its on cost and overhead rates in each regulatory year of the next regulatory control period in accordance with the methodologies set out in its CAM and submit both qualitative and quantitative supporting information to the AER as part of its annual pricing proposal.

[1182] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 416–417.
[1183] Energex, *Cost Allocation Method*, February 2009, pp. 19–21.

For the reasons discussed in section 18.3.2 Energex's on cost and overhead rates set out in table 18.5 are not binding on Energex in the next regulatory control period. Nevertheless, the illustrative quoted service examples and fee based services set out in appendix I, J and K were calculated using the on cost and overhead rates set out in table 18.5. The indicative on cost and overhead rates were derived using forecast direct expenditure.

Table 18.5: AER's nominal on cost and overhead rates for Energex's (dollar per dollar of labour expenditure) – confidential

	2010–11	2011–12	2012–13	2013–14	2014–15
Labour on costs					
Fleet on costs					
Materials on costs					
Overheads					

Ergon Energy

In the draft decision the AER did not accept Ergon Energy's proposed labour on cost rate of [redacted] and instead applied the benchmark labour on cost rate of 0.4024 (dollar per dollar of labour expenditure).[1184]

Ergon Energy stated in its revised regulatory proposal that its proposed on cost rate of [redacted] was prudent and efficient and represents actual cost incurred. It also considered the inclusion of a 9 per cent per annum superannuation allowance was insufficient as approximately [redacted] of its employees were on defined benefits of [redacted] per annum and the remaining [redacted] were on contributed benefits of 9 per cent per annum and accordingly an allowance of [redacted] per annum should apply.[1185] Ergon Energy clarified that the overtime labour on cost rate is applied to each employee classifications base labour rate instead of (rather than in addition to) the labour on cost rate.[1186]

Ergon Energy has not provided any new information that substantiates its proposed labour on cost rate and therefore the AER considers it appropriate to maintain the draft decision position and apply the benchmark labour on cost rate of [redacted] in each regulatory year of the next regulatory control period.

The AER's benchmark labour on cost rate does not include provision for superannuation. The AER sought additional information from Ergon Energy in relation to the calculation of its proposed labour on cost rate and its per annum superannuation allowance.[1187] The additional information provided confirms the proportion of employees on different superannuation schemes and the allowance for

1184 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 417.
1185 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 230.
1186 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 230.
1187 AER, information request AER.ERG.RRP.41, 19 April 2010.

defined benefits.[1188] On that basis, the AER is satisfied that Ergon Energy's proposed superannuation allowance is appropriate.

The application of labour on cost rates to Ergon Energy's employee classification overtime base labour rates described in the draft decision was incorrect. Ergon Energy advised that payroll tax is the only on cost applied to its overtime base labour rates.[1189] The AER considers it appropriate to apply the labour on cost rate and the overtime labour on cost rate to each employee classification's base labour rate and overtime base labour rates respectively. In the draft decision the AER's benchmark labour on cost rate included the cost of payroll tax of 0.0475 (dollar per dollar of labour expenditure).[1190] Accordingly, the AER considers it is appropriate to apply that on cost rate as Ergon Energy's overtime labour on cost rate.

The AER requires that Ergon Energy calculate its overhead rate in each regulatory year of the next regulatory control period and provide both qualitative and quantitative supporting information to the AER as part of its annual pricing proposal. The overheads shown in table 18.6 are based on the draft decision as Ergon Energy was unable to recalculate its overheads for this decision.[1191]

For the reasons discussed in section 18.3.2, Ergon Energy's overhead rates set out in table 18.6 are not binding on Ergon Energy in the next regulatory control period. Nevertheless, the illustrative quoted service examples and fee based services set out in appendix I, J and K were calculated using the overhead rates set out in table 18.6. The indicative overhead rates were derived using forecast direct expenditure.

Table 18.6: AER's nominal on cost and overhead rates for Ergon Energy's (per cent) – confidential

	2010–11	2011–12	2012–13	2013–14	2014–15
Labour on costs (including superannuation)					
Overtime labour on costs					
Overheads					

18.3.3.5 Profit margin

Energex

In the draft decision the AER did not include Energex's proposed profit margin formula component as it considered that the capital allowance provided an appropriate return on and return of capital for use of non–system assets used in the provision of quoted and fee based services.[1192]

Energex submitted that the draft decision highlighted the difficulty in facilitating competition while regulating the prices of the incumbent service provider and if the

[1188] Ergon Energy, response to information request AER.ERG.RRP.41, 21 April 2010.
[1189] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 230.
[1190] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 417.
[1191] Ergon Energy, email response to modelling request, 4 May 2010.
[1192] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 419–420.

capped prices are set too low, no competition will emerge. It argued that this outcome is inconsistent with the intention of clause 6.2.2(c)(1) as the rationale for alternative control services is to facilitate the development of competition. Energex also stated that its rationale for incorporating a profit margin was to leave some 'headroom' for competition to develop. It further stated that if a market is effectively competitive Energex should not be constrained from competing in the market for these services by the application of the regulated weighted average cost of capital (WACC).[1193]

Clause 6.2.2(c) of the NER is only relevant for classifying direct control services as either standard or alternative control services and are not matters that the AER is required to consider in establishing the efficient price for quoted and fee based services.

The AER notes that when an effectively competitive market is prevalent then it would consider classifying these services as negotiated or unregulated distribution services which could result in Energex being able to recover a rate of return without being constrained by the WACC, to the extent it is able to pass on the charges in a competitive market. However, in this decision quoted and fee based services are alternative control services and are subject to the AER's control mechanism. Hence, the regulated WACC provides an appropriate return on and return of capital for use of non–system assets used in the provision of quoted and fee based services.

Energex added that quoted and fee based services consist of a significant labour component and minimum use of regulated assets and consequently not allowing a profit margin will result in quoted and fee based services being provided at below market rates. The AER considers that the efficient labour costs approved by it are consistent with market rates and therefore Energex's charges for these services will not be below market rates.

For the above reasons, the AER is not satisfied that the inclusion of the profit margin formula component reflects the recovery of efficient costs and therefore does not considers it appropriate to include that component in Energex's formula used to derive the prices for quoted and fee based services in the next regulatory control period. The AER confirms its draft decision on the profit margin.

18.3.3.6 Other costs

Ergon Energy

In the draft decision the AER did not include Ergon Energy's proposed 'other costs' formula component as it considered it inappropriate to impose allowances for contingency costs on all customers.[1194]

In its revised regulatory proposal, Ergon Energy submitted that the AER has not understood the intent of the 'other costs' formula component. It added that the draft decision related to an explanation how 'other costs' were calculated for one scenario of a design and construction of a new large customer connection assets service and not 'other costs' generally. Ergon Energy stated that 'other costs' relate to one–off

[1193] Energex, *Revised regulatory proposal*, January 2010, pp. 58–59.
[1194] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 420.

service delivery costs including hire or supply of additional equipment, assets or labour and contingency costs. It added that ‘other costs’ are incurred as a result of a customer request and if not for that request it would not incur these costs and it is therefore appropriate for these costs to be passed through to the customer.[1195]

Ergon Energy has applied the ‘other costs’ formula component to four of 37 illustrative quoted service examples and not to fee based services. The four quoted services are the three examples of the provision of design and construction of a new large customer connection assets service and the removal or relocation of Ergon Energy’s assets at customer’s request service.[1196]

The AER notes that in Ergon Energy’s illustrative quoted services examples ‘other costs’ expenditure in each example is an input.[1197] It is therefore not possible to identify to what this expenditure relates. Ergon Energy did not provide any information that supports its contention that ‘other costs’ hire or supply of equipment, assets of labour and not just contingency costs. The AER sought additional information from Ergon Energy.[1198] It explained that its Phoenix estimating tool is used internally to cost projects and provides information on labour and vehicles for specific scenarios. However, Ergon Energy did not explain what these scenarios were or the specific costs to which they relate.[1199]

The AER considers that Ergon Energy has not provided sufficient information that substantiates the basis of its proposed ‘other costs’ formula component expenditure, which has precluded an assessment of the efficiency of that expenditure.

In the draft decision the AER considered that the inclusion of allowances for contingency costs provides no incentive for a DNSP to seek productivity gains or to improve its internal processes or procedures. Quoted and fee based services are implemented at a customer’s request. Nevertheless, customers should only pay the efficient cost of providing those services.

The AER is not satisfied that the inclusion of the ‘other costs’ formula component reflects the recovery of efficient costs and therefore does not consider it appropriate to include that component in Ergon Energy’s formula to be used to derive the prices for quoted services in the next regulatory control period.

18.3.4 Price path

As discussed in section 18.3.2, the AER considers it appropriate to include greater flexibility in the application of input cost escalators, on cost and overhead rates in the formula based price cap control mechanism. As a result, the price path for the Qld DNSPs’ respective labour, contractor services and materials formula components set out in table 7.8 are indicative only and do not represent a binding cap on the potential escalation of labour, contractor services and materials to be used in the provision of quoted and fee based services in the next regulatory control period.

[1195] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 231.
[1196] Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP918c.
[1197] Ergon Energy, *Revised regulatory proposal*, January 2010, attachments RP920c and RP921c.
[1198] AER, information request AER.ERG.RRP.41, 19 April 2010.
[1199] Ergon Energy, response to information request AER.ERG.RRP.41, 21 April 2010.

Consistent treatment between quoted and fee based services is necessary as each DNSP is to apply the same respective formula to derive the cost of providing individual quoted and fee based services.

A specific price path is not required for the Qld DNSPs' on cost and overheads as these rates are not specific formula components. However, the rates specified in tables 18.5 and 18.6 are also indicative only.[1200] As specified in section 18.3.3.4 Energex is required to calculate its on cost and overhead rates in each regulatory year of the next regulatory control period in accordance with the methodologies set out in its CAM. Ergon Energy is required to calculate its overhead rate consistent with its CAM in each regulatory year of the next regulatory control period.

The prices for the Qld DNSPs' illustrative quoted service examples and fee based services set out in appendix I, J and K respectively are indicative only and have been determined using the indicative price paths as described above.

18.3.5 Demonstration of compliance with the price cap

Clause 6.12.1(13) of the NER requires that the AER's distribution determination include a decision on how compliance with the control mechanisms for quoted and fee based services is to be demonstrated.

Compliance with the price cap control mechanisms applicable to the Qld DNSPs' quoted and fee based services is to be demonstrated in each regulatory year of the next regulatory control period through the pricing proposal, where the Qld DNSPs must:

- Apply the AER approved price cap control mechanism formula, set out in section 18.4 of this decision, to calculate the price for each illustrative configuration of each individual quoted service and fee based service to be offered in the relevant regulatory year.

- Provide quantitative information to the AER that demonstrates the calculation of the price of each illustrative quoted service example and fee based service.

- Set out in its pricing proposal the nature and extent of any variation to an individual formula component, on cost or overhead rate from that applicable in the previous regulatory year that is above the indicative illustrative quoted service examples and fee based services set out in appendix I, J and K of this decision.

- Set out in its pricing proposal the nature and extent of any variation or adjustment to the methodology employed to derive a formula component escalator or on cost or overhead rate.

[1200] As discussed in section 18.3.3 Energex's capital allowance is binding. As discussed in section 18.3.3.4 Ergon Energy's labour on cost rates (ordinary time and overtime) are binding.

- Submit to the AER the volume of each quoted and fee based service provided and the revenues recovered from the provision of each quoted and fee based service in the preceding regulatory year.[1201]

The process described in the preceding paragraph sets out how compliance with the control mechanism is to be demonstrated by the Qld DNSPs. The AER makes some additional observations about the Qld DNSPs' obligations under the NER and the resolution of possible disputes arising in relation to certain services.

The AER is responsible for approving a DNSP's pricing proposal if it is satisfied it complies with the requirements of Part I of chapter 6 of the NER, any applicable distribution determination, and if all forecasts associated with the proposal are reasonable. The AER notes that under clause 6.18.9(a) of the NER the Qld DNSPs are also required to maintain on their website the applicable charging parameters for each tariff and a statement of expected price trends indicating how the DNSP expects prices to change over the regulatory control period including the reasons for these expected changes.

Due to the variable nature of the inputs used to derive the prices of quoted services, the AER acknowledges that in some circumstances it may be difficult for customers to determine whether a quoted service provided by the Qld DNSPs is compliant with the price cap control mechanism. However, the AER notes under clause 6.22.1 of the NER, disputes arising over the terms and conditions of access to direct control services are considered access disputes for the purposes of Part 10 of the NEL.

Under the price cap control mechanism the price for each fee based service approved by the AER in its assessment of the Qld DNSPs' pricing proposals is the maximum price the Qld DNSPs can charge for that fee based service in the relevant regulatory year. As is the case for quoted services, disputes arising over the terms and conditions of access to direct control services are considered access disputes for the purposes of Part 10 of the NEL.

18.4 AER conclusion

The AER considers it appropriate to include greater flexibility in the application of input cost escalators, on cost and overhead rates within the formula based price cap control mechanisms for quoted and fee based services as described in section 18.3.2.

The AER has approved in this decision the formula proposed by Energex to derive the prices for quoted and fee based services with the exception of the profit margin component. The formula Energex is to use to derive the prices for quoted and fee based services is:

$$\text{Price} = \text{Labour} + \text{Contractor Services} + \text{Material} + \text{Capital Allowance} + \text{GST}$$

where:

[1201] The preceding regulatory year is the regulatory year prior to the regulatory year in which the pricing proposal is submitted. For example, the pricing proposal for 2010–11 must include the volume of and revenue recovered from the provision of quoted and fee based service in 2008–09.

Labour (including on costs and overheads)—consists of all labour costs directly incurred in the provision of the service, labour on costs, fleet on costs and overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service.

Contractor services (including overheads)—reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred as part of performing the service, for example permits for road closures or footpath access, are passed on to the customer.

Materials (including overheads)—reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads.

Capital allowance—represents a return on and return of capital for non-system assets (for example vehicles, IT and tools) used in the provision of the service.

GST—represents the goods and services tax (GST) component of the service charge.

The AER has approved in this decision the formula proposed by Ergon Energy to derive the prices (P_i) for quoted and fee based services with the exception of the 'other costs' component. The AER has also amended the application of Ergon Energy's capital allowance formula component. The formula Ergon Energy is to use to derive the prices for quoted and fee based services is:

$$P_i = L_i + M_i + CA_i + GST_i$$

where:

L_i is the cost of labour involved in the delivery of the service (inclusive of on costs and overheads), calculated as the product of an hourly rate and the time spent by the personnel. This amount includes both travel time and time spent delivering the service.

M_i is the cost of non-capitalised materials expensed in the delivery of the service (inclusive of overheads).

CA_i reflects the return on and return of non-system capital employed in the delivery of the service (for example, trucks and IT systems), which is calculated as a dollar per dollar of labour expenditure in accordance with section 18.3.3.3 of this decision.

GST_i the goods and services tax component of the service charge.

The AER accepted Energex's updated 2008–09 base labour rate for its customer connection employee classification which is escalated and used to calculate the prices for its fee based services in the first regulatory year of the next regulatory control period.

Based on the information provided by Ergon Energy, the AER accepted that it is not necessary to include three additional employee classifications (contractor, system operator and trainee) and that the employee classifications included in the draft decision are sufficient to derive the prices for quoted and fee based services in the next regulatory control period.

The AER is satisfied that the composition of Ergon Energy's illustrative quoted service configurations correctly applied and appropriately allocated each employee classifications to the type of skills required to undertake each individual service.

The AER accepted Energex's updated calculation of its general capital allowance for non–system assets used in the provision of quoted and fee based services. The calculations set out in appendices I, J and K respectively reflect the allowances provided in the AER's decision.

The AER did not accept Ergon Energy's proposed capital allowance and determined an alternative allowance for the first regulatory year of the next regulatory control period. Ergon Energy is required to recalculate its capital allowance in each of the remaining regulatory years of the period. The calculations set out in appendix I, J and K respectively reflect the allowances provided in the AER's decision.

On cost (labour, fleet and materials) and overhead rates will be applied to Energex's direct costs (labour, materials and vehicles). The AER requires that Energex calculate its on cost and overhead rates in each regulatory year of the next regulatory control period in accordance with the methodologies set out in its CAM and submit both qualitative and quantitative supporting information to the AER as part of its annual pricing proposal.

An on cost rate of [redacted] and [redacted] will be applied to Ergon Energy's respective base labour rates and overtime base labour rate and an overhead rate will be applied to its direct costs (labour, materials and vehicles). The AER requires that Ergon Energy calculate its overhead rate in each regulatory year of the next regulatory control period in accordance with the methodologies set out in its CAM and submit both qualitative and quantitative supporting information to the AER as part of its annual pricing proposal.

The AER has determined the capped price of providing the illustrative configuration of each individual quoted services and fee based service in the first regulatory year of the next regulatory control period. In section 18.3.4 the AER established a methodology for deriving a price path for each individual formula component in the remaining regulatory years of the next regulatory control period.

The process and requirements for demonstrating compliance with the price cap control mechanisms for quoted and fee based services is set out in section 18.3.5.

The prices for the Qld DNSPs' quoted service illustrative configurations and fee based services set out in appendix I, J and K respectively are indicative only and have been determined using the indicative price paths described in section 18.3.4.

18.5 AER decision

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Energex's quoted services is:

- caps on the prices of indicative individual services in the first regulatory year of the next regulatory control period
- price paths, as set out in section 18.3.4 of this decision, for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Energex's fee based services is:

- caps on the prices of individual services in the first regulatory year of the next regulatory control period
- price paths, as set out in section 18.3.4 of this decision for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(13) of the NER, Energex's compliance with the control mechanisms for quoted services and fee based services is to be demonstrated through the annual pricing approval process. The process for demonstrating compliance is specified in section 18.3.5 of this decision.

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Ergon Energy's quoted services is:

- caps on the prices of indicative individual services in the first regulatory year of the next regulatory control period
- price paths, set out in section 18.3.4 of this decision, for the remaining regulatory years of the next regulatory control period.

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to Ergon Energy's fee based services is:

- caps on the prices of individual services in the first regulatory year of the next regulatory control period
- price paths, set out in section 18.3.4 of this decision for the remaining years of the next regulatory control period.

In accordance with clause 6.12.1(13) of the NER, Ergon Energy's compliance with the control mechanisms for quoted services and fee based services is to be demonstrated through the annual pricing approval process. The process for demonstrating compliance is specified in section 18.3.5 of this decision.

Glossary

AASB	Australian Accounting Standards Board
ABS	Australian Bureau of Statistics
ACG	Allen Consulting Group
AECOM	AECOM Australia Pty Ltd
AEM	Access Economics Macro model
AEMC	Australian Energy Market Commission
AH	after hours
ANZSIC	Australian and New Zealand Standard Industry Classification
AON	AON Global
AR	allowed revenue
ASA	average speed of answer
ATO	Australian Taxation Office
BBI	Babcock and Brown Infrastructure
BH	business hours
bppa	basis points per annum
CAM	cost allocation method
CAPM	capital asset pricing model
CBD	central business district
CEG	Competition Economists Group
Cement Australia	Cement Australia Pty Ltd
CFC	Construction Forecasting Council
CGS	Commonwealth Government Securities
CIA	corporation initiated augmentation
CICW	customer initiated capital works
CPRS	carbon pollution reduction scheme
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DMS	Distribution Management System
DRP	debt risk premium
DSM	demand side management
DUOS	distribution use of system
EBSS	efficiency benefit sharing scheme
ECCSA	Energy Consumers Coalition of South Australia

EDSD Review	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
EGW	electricity, gas and water
ETS	emissions trading scheme
EUAA	Energy Users Association of Australia
EUCA	Energex Union Collective Agreement
EWP	elevated work platform
FFA	field force automation
Finity	Finity Consulting Pty Ltd
FiT	feed–in tariff
FY	financial year
gamma	the assumed utilisation of imputation credits
GFC	global financial crisis
GOS	grade of service
GRP	gross regional product
GSL	guaranteed service levels
GSP	gross state product
GST	goods and services tax
GWh	gigawatt hour
HOHS	Housing and Homeless Services
Huegin	Huegin Consulting
IAM	identity and access management
IBNR	incurred but not reported
ICT	information, communications and telecommunications
IT	information technology
KRA	key result area
kV	kilovolt, (one thousand volts)
kWh	kilowatt hour
LME	London Metal Exchange
LPI	labour price index
LV	low voltage
MAIFI	momentary average interruption frequency index
MAR	maximum allowed revenue
MCE	Ministerial Council on Energy
McGrathNicol	McGrathNicol Corporate Advisory

MED	major event day
MMA	McLennan Magasanik Associates
MRP	market risk premium
MSATS	market settlement and transfer solution
MSS	minimum service standards
MTN	medium term notes
MW	megawatt, (one thousand kilowatts)
MWh	megawatt hour
NARMCOS	network asset replacement maintenance capital expenditure operating expenditure summary
NDSC	negotiated distribution service criteria
NERA	NERA Economic Consulting
NIEIR	National Institute of Economic and Industrial Research
NMI	national metering identifier
NMP	network management plan
NPV	net present value
NTER	national tax equivalence regime
OH	overhead
OLS	ordinary least squares
P–F	Potential for failure
PoE	probability of exceedence
PTRM	post–tax revenue model
PV	photovoltaic
PwC	PricewaterhouseCoopers
QCOSS	Queensland Council of Social Service
R&D	research and development
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RCP	Resource Coordination Partnership
RFM	roll forward model
RIN	regulatory information notice
SAHA	SAHA International Ltd
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SEO	seasoned equity offering
SFG	Strategic Finance Group Consulting

SKM	Sinclair Knight Merz Pty Ltd
SORI	AER, *Electricity transmission and distribution network service providers, Statement of revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009.
SNAP	sub–transmission network augmentation project
SPARQ	SPARQ Solutions
STPIS	service target performance incentive scheme
Synergies	Synergies Economic Consulting
TEC	Total Environment Centre
the WACC review	AER, *Final decision, Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, 1 May 2009
theta	the utilisation rate of imputation credits
Tribunal	Australian Competition Tribunal
TUOS	transmission use of system
TWI	trade weighted index
UbiNet	Ubiquitous Network
UCA	union collective agreement
UG	underground
UK	United Kingdom
UnitingCare	UnitingCare Australia
WACC	weighted average cost of capital

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[1202]
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

1202 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[1203]
		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

1203 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 – Low Voltage 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[1204]

   (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 class 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

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[1204] 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 class, 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 class 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 (as appropriate).

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 (as appropriate).
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 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 (as appropriate).
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 (as appropriate).

D. Distribution use of system unders and overs account

To demonstrate compliance with their distribution determinations in 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):[1205]

1. opening balance for year t–2 and year t[1206]
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 any under/over adjustment approved by the regulator for year t–2 (in relation to year t–4), less the 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 decision. In such circumstances, the balance at the end of the regulatory control period will reflect the amount by which the adjustment exceeded the first tolerance limit (that is, the amount by which the under/over adjustment exceeded 2 per cent of the DNSP's MAR for year t).

1205 For the first two years of the next regulatory control period, the assessment of DUOS under/over recoveries will be simplified. The QCA has already determined the Qld DNSPs' DUOS under/over recoveries for 2008–09. The QCA has also determined a revised aggregate annual revenue requirement for 2009–10 which will be compared to actual revenues received from DUOS charges for that year. QCA, letters to the AER, 28 January 2010 and 11 March 2010.

1206 The opening balance for year t–2 should be indexed by WACC to the start of year t–2 before it is indexed by WACC for two years (under item 2 above) to be in year t dollars.

The proposed prices for year t are based on the sum of the MAR for year t plus any adjustment for DUOS under or over recoveries.

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

	year t–2 (actual)	year t (forecast)
Revenue from DUOS charges	37 021	45 761
Less under/over adjustment approved by the regulator for year t–2	800[a]	na
Less MAR for the relevant year	34 365	46 694
Allowed revenues (AR_t)	34 100	37 000
Service quality performance reward/penalty (S_t)	–100[b]	100
Capital contribution overs/unders adjustment (C_t)	–35[c]	4
Transitional adjustments ($Transitional_t$)	400	90
Approved pass throughs ($Passthrough_t$)	0	9500
Under/over recovery for regulatory year	1856	–933
DUOS unders and overs account		
Nominal WACC	9.70%	na
Opening balance	1000[d]	3437
Interest on opening balance	203	na
Under/over recovery for regulatory year	1856	–933[f]
Interest on under/over recovery for regulatory year	378	na
Closing balance	3437[e]	2504[g]

(a) In this example, the regulator agreed that the DNSP could over recover its revenues by $1 million in year t–2 due to under recoveries in year t–4.
(b) In this example, the DNSP has incurred a service quality performance penalty.
(c) In this example, the DSNP has received more capital contributions in year t–4 than was forecast for that year. Consistent with the MAR formula in chapter 4 of this decision, the $35 000 is an indexed amount to bring the over recoveries to year t–2 values.
(d) The opening balance for year t–2 is based on any DUOS under/over recoveries prior to year t–2 that have not been returned to (or recovered from) customers yet.
(e) In this example, the under/over adjustment required to achieve zero balance ($3437 000) on the DUOS unders and overs account would exceed the second tolerance limit. Therefore the adjustment has been capped, with the approved adjustment assumed to be 2 per cent ($933 000) of the MAR for year t.
(f) This figure will be the 'under/over adjustment approved by the regulator for year t–2' for the annual price approval process in two year's time.
(g) This figure should be discounted by one year's WACC to provide the opening balance for the DUOS unders and overs account for the price approval process next year.

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 any under/over adjustment approved by the regulator for year t–2 (in relation to year t–4), 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 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	37 221	36 500
Less under/over adjustment approved by the regulator for year t–2	1000[a]	na
Less total transmission related payments	34 365	38 734
Transmission charges to be paid to TNSPs	25 214	29 557
Avoided TUOS payments	572	681
Inter-DNSP payments	8579	8496
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[b]
Interest on under/over recovery for regulatory year	378	na
Closing balance	2234	0

(a) In this example, the regulator agreed that the DNSP could over recover its revenues by $1 million in year t–2 due to under recoveries in year t–4.

(b) This figure will be the 'under/over adjustment approved by the regulator for year t–2' for the annual price approval process in two year's time.

F. Cost escalators

This appendix sets out the AER's consideration of issues raised in response to the draft decision on materials and labour cost escalators for the Qld DNSPs.

F.1 AER draft decision

The AER did not accept the methodologies the Qld DNSPs used to develop real cost escalators in their regulatory proposals. The AER substituted the cost escalators proposed by the Qld DNSPs with those set out in table F.1.

Table F.1: AER draft decision on real cost escalators for Energex and Ergon Energy (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Energex							
Materials	–2.38	0.02	2.18	1.59	0.29	–0.16	–0.32
Land and easements	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Construction	2.8	1.1	–0.9	–0.2	1.0	0.0	–1.5
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
Ergon Energy							
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
Crude oil	–17.3	–8.3	22.0	15.8	5.5	1.7	0.4
Exchange rates	0.744	0.800	0.656	0.603	0.585	0.581	0.580
Inflation rate	1.5	2.7	2.0	2.5	2.5	2.5	2.5
Commercial land	4.2	5.5	5.4	5.0	5.0	5.4	5.8
Rural land	6.8	8.1	8.0	7.6	7.6	8.0	8.4
Construction	2.8	1.1	–0.9	–0.2	1.0	0.0	–1.5
Internal labour	0.07	2.13	0.58	0.58	1.16	1.54	1.53
Contractor labour	0.9	1.5	0.1	0.6	1.2	1.6	1.5

Source: AER, *Draft Decision, Queensland draft distribution determination*, November 2009, Appendix H.

Energex

The AER did not consider Energex's escalation rates for labour costs to be acceptable because constant wage growth forecasts did not accurately represent the volatility of the current market and the forecasts did not reflect the most recently available data.

The AER did not consider Energex's escalation rates for materials costs to be acceptable because they did not reflect actual and forecast changes in materials costs, most notably significant decreases in materials costs in 2008–09 and 2009–10.

Ergon Energy

The AER did not consider Ergon Energy's application of a single escalation rate to internal and contract labour costs to be appropriate because it diminished the commercial incentive for Ergon Energy to negotiate competitive wage outcomes and it did not differentiate between specialist and general labour resources.

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

F.2 Revised regulatory proposals

Energex

Energex stated that it did not necessarily accept the rationale behind all of the adjustments made by the AER in the draft decision, including those made in relation to cost escalators[1207] and indicated that it would provide further comment on cost escalators in its submission. Nevertheless, Energex acknowledged and applied the AER's escalation rates in its revised regulatory proposal. Energex indicated it expected the AER to update the real cost escalators in the final decision.[1208]

Ergon Energy

Labour

Ergon Energy did not accept the labour cost escalators applied by the AER in the draft decision. Ergon Energy reinstated its internal and contract labour cost escalators, as set out in its regulatory proposal.[1209]

Ergon Energy considered that the AER, under the NER, must approve its proposed escalators if they are within an acceptable range. Ergon Energy accepted that the AER's escalators may be in the reasonable range, but noted the AER did not provide any information suggesting Ergon Energy's labour escalators were outside a reasonable range. Ergon Energy considered that the AER did not provide sufficient information detailing the derivation of its internal and contract labour cost escalators.[1210]

[1207] Energex, *Revised regulatory proposal*, January 2010, p. 1.
[1208] Energex, *Revised regulatory proposal*, January 2010, p. 18.
[1209] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 97.
[1210] Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 86–87.

Ergon Energy further considered that its proposed labour escalators were consistent with costs faced by an efficient and prudent DNSP in Ergon Energy's position and did not consider that applying such labour cost escalators would impact on incentives to negotiate competitive future wage outcomes.[1211]

Ergon Energy did not consider it appropriate for the AER to weight its general and technical labour costs, given its Union Collective Agreement (UCA) applied equally to both categories, or to apply different labour costs escalators to contractors and internal labour.[1212]

Construction Costs

Ergon Energy accepted the AER's approach to deriving construction cost escalators and updated these construction cost forecasts with the latest available data released from the Construction Forecasting Council (CFC) in November 2009.[1213]

Materials

Ergon Energy rejected the AER's use of London Metals Exchange (LME) 63 month and 123 month forward contract prices for aluminium and copper because of the limited liquidity at present in these long term markets. Ergon Energy also stated its understanding that prices for LME 63 month and 123 month forward contracts do not reflect bids and offers, but rather are determined by an LME Quotations Committee using a fair value method. Ergon Energy also stated that the AER had not presented a valid reason why it changed its method of calculating escalators for aluminium and copper from that used in its NSW decision. For these reasons, Ergon Energy used Consensus Economics long term forecasts instead of LME 63 month and 123 month forward contract prices to calculate its aluminium and copper escalators.[1214]

Ergon Energy rejected the AER's removal of the trade weighted index (TWI) from the calculation of materials costs escalators.[1215] Ergon Energy claimed that the AER had misunderstood the use of the TWI in SKM's model and that the model produces prices that more closely reflect actual outcomes when the TWI is included than it does when the TWI is omitted from the model.[1216]

Ergon Energy's revised real cost escalators are presented in table F.2.

[1211] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 86.
[1212] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 96.
[1213] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 139.
[1214] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 137.
[1215] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 138.
[1216] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 137.

Table F.2: Ergon Energy revised real cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Aluminium	–16.7	–5.3	21.6	9.4	–5.1	–7.6	–7.9
Copper	–20.2	10.8	16.5	4.9	–9.4	–12.5	–13.6
Steel	10.4	–23.2	33.4	15.1	–6.2	–9.4	–9.9
Crude oil	–10.7	–1.8	30.4	9.2	2.4	0.0	–0.4
Exchange rates	0.744	0.800	0.656	0.603	0.585	0.581	0.580
Inflation rate	1.5	2.5	2.25	2.5	2.5	2.5	2.5
Trade weighted index	16.6	1.6	0.0	0.0	0.0	0.0	0.0
Commercial land	6.6	5.6	5.85	5.6	5.6	5.6	5.6
Rural land	9.3	8.3	8.6	8.3	8.3	8.3	8.3
Construction costs	1.8	1.5	–0.9	0.6	2.1	1.5	–0.4
Internal labour (nominal)[a]	5.1	5.1	4.4	4.5	4.5	4.5	4.5
Contractor labour (nominal)[a]	5.1	5.1	4.4	4.5	4.5	4.5	4.5

Sources: For labour escalators, Ergon Energy, *Revised regulatory proposal*, January 2010, p. 97. For TWI escalators, Ergon Energy, *Response to AER.ERG.RRP.29 – Cost escalators*, 23 March 2010. For all other escalators, Ergon Energy, *Response to AER.ERG.RRP.29 – Cost escalators*, 12 March 2010.

(a) In response to a question from the AER (AER.ERG.RRP.29, 23 March 2010), Ergon Energy indicated that its nominal escalation rate for 2008–09 was 6.8 per cent instead of 5.1 per cent due to an EDSD allowance. The AER notes that the 6.8 per cent figure contradicts Ergon Energy's regulatory proposal and revised regulatory proposal, both of which indicated a rate of 5.1 per cent. The AER also notes previous responses from Ergon Energy that its UCA rate of 4.5 per cent included EDSD costs (Ergon Energy responses to AER.ERG.15.03 and AER.ERG.15.04). Based on the information available, the AER understands Ergon Energy's nominal labour escalation rate for 2008–09 to be 5.1 per cent.

F.3 Consultant review

The AER engaged Access Economics to provide an update on its growth forecasts for general state labour price indices (LPIs) and the electricity, gas and water (EGW or utilities) sector for NSW, Victoria, Queensland, South Australia, ACT and Australia.[1217]

Access Economics noted that changing economic conditions were the key driver for revisions to its September 2009 forecasts.[1218] However, Access Economics also noted

[1217] Access Economics, *Forecast growth in labour costs: March 2010 report,* 16 March 2010.
[1218] Access Economics, *Forecast growth in labour costs,* 16 September 2009.

that the following technical changes to historical variables have impacted changes to its forecasts:[1219]

- new industry projections used 2006–07 as the base year
- application of the new ANZSIC06 structure
- LPI measures were rebased to 2008–09.

Queensland labour growth forecasts

Access Economics further noted that the technical changes have affected its detailed (industry by state) results, as outlined below:[1220]

- application of Access Economics' derived industry output and industry LPI estimates
- application of rebased estimate of historical LPI growth from September 2009 report for the period before September 2008
- where LPI data was not available and average weekly earnings measures were only available from June 2009, sectoral national growth rates were assumed.

General labour

Access Economics considered the Queensland economy has been a key driver of national economic growth over the past decade and resultantly, its labour cost growth has been above that of Australia as a whole. However, Queensland has suffered from the economic downturn more than most, notably impacts in the state's mining and tourism sectors have pegged its labour cost growth back to the national average in recent quarters.[1221]

Further to this, Access Economics projected Queensland's economic growth to slow over the next 18 months due to the combination of anticipated falls in engineering activity, commercial and housing construction weaknesses, alongside the lagged impact of actioning construction decisions. Subsequently, labour cost growth will be impacted. Access Economics forecast Queensland's labour cost growth to slow to 0.2 per cent, in real terms, over the next year and revert back to the projected national average from mid–2011.[1222]

Access Economics' general labour forecasts are set out in table F.3 below.

[1219] Access Economics, *Forecast growth in labour costs,* 16 September 2009, p. 35. See Appendix F for further information on the conversion of ANZSIC93 to ANZSIC06.

[1220] Access Economics, *Forecast growth in labour costs,* 16 March 2010, p. 48 and Appendix F.

[1221] Access Economics, *Forecast growth in labour costs,* 16 March 2010, p. 27.

[1222] Access Economics, *Forecast growth in labour costs,* 16 March 2010, pp. 28, 69.

Electricity, gas and water labour[1223]

Access Economics considered that further to the downturn economic growth faced by Queensland and its impacts on labour cost growth, this impact has fed into the EGW sector wages growth. Access Economics noted that the year to June 2009 growth rates were approaching 6 per cent due to competition for scarce skills and available workers. However, this growth rate eased quite significantly for the remainder of the year given falling demand for the types of workers employed by the utilities sector.[1224] Access Economics considered future construction projects as important supply side developments which will assist in the demand for workers. As a result, Access Economics concluded that Queensland's EGW sector wage growth may experience further weakness in the first half of 2010. However, data reported by Access Economics indicated that wage growth is likely to revert to slightly above the national average from 2011.[1225]

Access Economics' EGW sector labour forecasts are set out in table F.3 below.

Table F.3: Access Economics real labour escalation rates for general labour and the EGW sector in Queensland

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
General	0.4	0.5	0.2	0.4	0.9	1.4	1.5
EGW	1.1	1.1	1.0	0.9	1.3	1.5	1.6

Source: Access Economics, *Forecast growth in labour costs*, 16 March 2010, p. 69.

F.4 Submissions

Energex provided a detailed proposal on cost escalation in its submission. Energex stated that the economic climate at the time of the regulatory proposal justified the use of constant cost escalation rates. Energex stated that the improving and less volatile economic outlook allowed greater confidence in data based forecasting methods, and therefore prepared updated forecasts.[1226]

Energex noted that the AER recognised that escalation forecasts will have to be updated at the time of the final determination.[1227]

Labour

Energex expressed concern at the use of Access Economics' labour cost forecasts by the AER. Energex stated that the model did not give sufficient weight to the specific challenges faced by electricity supply entities. Further, Energex expressed concern

[1223] ANZSIC06 now includes waste services in the utilities sector. For ease of reference the AER will continue to refer to this as the EGW sector.
[1224] Access Economics, *Forecast growth in labour costs,* 16 March 2010, pp. 70–71.
[1225] Access Economics, *Forecast growth in labour costs,* 16 March 2010, pp. 70–71.
[1226] Energex, *Submission on Draft Determination*, February 2010, p. 3.
[1227] Energex, *Submission on Draft Determination*, February 2010, p. 4.

that the proprietary model employed by Access Economics was not sufficiently explained and that the predictive performance of the model was therefore unclear.[1228]

Energex considered that the mechanism used by the AER to adjust for the impact of the Energex Union Collective Agreement did not reflect the efficiency or prudence of real wage increases. As such, Energex proposed that Pricewaterhouse Coopers (PwC) labour cost escalation forecasts should be used in the final decision.[1229]

Energex considered the adjustment mechanism employed by the AER to account for different escalation rates between internal staff and external contractors to be arbitrary and without a clear basis. Energex stated that updated PwC forecasts reflect the same escalation rate for internal staff and external contractors.[1230]

Materials

Energex engaged Sinclair Knight Merz Pty Ltd (SKM) to produce materials cost escalators that included weightings that reflect the underlying cost drivers of Energex's capex program.[1231]

Energex stated that SKM addressed the issues raised by the AER concerning the estimates SKM prepared for Ergon Energy.[1232] Energex noted that while it preferred to base forecasts solely on futures prices, it considered long term LME futures markets for aluminium, copper and steel were not sufficiently liquid to provide robust forecasts.[1233] Instead, Energex stated that SKM's use of economic consensus prices more reasonably reflects the capital expenditure and operating expenditure criteria and objectives.[1234]

Construction

Energex provided updated estimates of building and construction cost escalators based on the latest forecasts from the CFC.[1235]

The cost escalators proposed by Energex in its submission are presented in table F.4.

[1228] Energex, *Submission on Draft Determination*, February 2010, p. 8.
[1229] Energex, *Submission on Draft Determination*, February 2010, p. 11.
[1230] Energex, *Submission on Draft Determination*, February 2010, p. 12.
[1231] Energex, *Submission on Draft Determination*, February 2010, p. 5.
[1232] Energex, *Submission on Draft Determination*, February 2010, p. 4.
[1233] Energex, *Submission on Draft Determination*, February 2010, pp. 4-5.
[1234] Energex, *Submission on Draft Determination*, February 2010, p. 5.
[1235] Energex, *Submission on Draft Determination*, February 2010, p. 7.

Table F.4: Energex's revised real cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Materials	–1.4	–4.0	10.8	5.1	–2.2	–3.6	–3.4
Construction	1.8	1.6	–0.9	0.6	2.1	1.4	–0.4
Internal labour	3.4	1.7	2.5	0.9	0.8	0.7	0.6
Contract labour	3.4	1.7	2.5	1.1	1.0	0.8	0.7

Sources: For construction and labour respectively, Energex, *Submission on draft decision*, February 2010, p. 7 and p. 13. For materials, Energex, *Submission on draft decision*, Appendix 1.0 – Energex materials and cost escalation forecasts for 2010–15, SKM, February 2010, p. 5.

Note: Energex advised that the materials escalators presented in its submission were incorrect. The correct values are presented in the table. Energex, response to AER.EGX.RP.11: Follow up to AER.EGX.RP.04, 10 March 2010.

F.5 Issues and AER considerations

F.5.1 Labour

The Qld DNSPs did not accept the labour cost escalators applied by the AER in its draft decision.

The AER notes that the Qld DNSPs raised a number of concerns in relation to the following:

- the modelling undertaken by Access Economics for the AER
- the AER's recognition of impacts arising from the DNSPs' UCAs
- the use of different escalation rates for internal labour and external contractors.

Modelling by Access Economics

The AER notes that Energex raised a number of specific concerns in relation to Access Economics macro model (AEM) [1236] and that Ergon Energy considered Access Economics' approach was not sufficiently supported.[1237] Energex considered Access Economics placed insufficient weighting on circumstances faced by electricity supply entities and outlined concerns with the transparency supporting the compilation of Access Economics forecasts.[1238]

The AER notes that the structure of the AEM has evolved over time in response to various forecasting and policy challenges. The AER notes Energex's comments pertain to a previous version of the AEM model. The AER is satisfied that Access Economics' methodology for forecasting labour costs growth is robust given the

[1236] AEM was used by Access Economics for the purpose of providing labour escalation for the Powerlink revenue determination.

[1237] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 87.

[1238] Energex, *Submission on draft determination*, February 2010, p. 8.

forecasts were developed using a formal econometric modelling approach.[1239] The AER considers the AEM is adequately supported by information contained in Access Economics' report (both its September 2009 and March 2010 versions) and is further supported by information discussing the concordance between ANZSIC93 and ANZSIC06.[1240]

Further, in response to the DNSPs' concerns, the AER requested a copy of AEM model documentation (version 6) to undertake further review of the AEM.[1241] The AER is satisfied information supporting Access Economics' equations, parameters and variables is well documented and robust. The AER is also satisfied that the components of Access Economics' model have been correctly applied and that results have been correctly interpreted.

Recognition of UCA impacts

The AER notes that the Qld DNSPs raised issues in relation to how wage increases under their respective UCAs should be applied.

The AER notes Energex's statement that it did not understand the AER's treatment of Energex's UCA impacts for 2008–09, 2009–10 and 2010–11, citing a mixture of actual and forecast data which caused underestimates of the escalation rates for 2009–10 and 2010–11.[1242] The AER reviewed its modelling and confirms that actual and forecast data was not mixed in calculating the rates for 2008–09 and 2009–10. The AER disagrees with Energex that the 2008–09 UCA impacts have been underestimated. However, the 2010–11 rate was based on forecasts in combination with UCA impacts. The inclusion of UCA impacts was a modelling error.

The AER confirms the draft decision[1243] and previous regulatory decisions[1244] that it is not appropriate to uncritically apply DNSPs' current UCA rates into the next regulatory control period. To do so would reduce the incentives on DNSPs to negotiate efficient labour outcomes and would represent a shift from an incentive based regulation framework to cost of service regulation. The AER has corrected the modelling error in relation to UCA impacts in 2010–11 for this decision and notes that it results in a decrease in the escalation rate for 2010–11.

The AER notes that the Qld DNSPs considered that the real wage increases implied by the UCAs were prudent and efficient for a range of reasons, including:

- the agreements reflected the circumstances in which the DNSPs operated, including the economic environment[1245]

[1239] See AER, *Draft decision, Queensland draft distribution determination,* November 2009, p. 605 for an overview of the AEM approach.
[1240] Access Economics, *Forecast growth in labour costs,* 16 March 2010, Appendix F.
[1241] Full AEM model documentation was provided to the AER on a commercial-in-confidence basis.
[1242] Energex, *Submission on draft determination,* February 2010, p. 10.
[1243] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 611 and 613.
[1244] AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 493.
[1245] Energex, *Submission on draft determination,* February 2010, Appendix 2.0, p. 27; and Ergon Energy, *Revised regulatory proposal*, January 2010, p. 85.

- the difficult and rigorous nature of the negotiations[1246]
- the UCA rates are comparable with other recent relevant wage negotiation outcomes.[1247]

The AER does not consider that these arguments represent sufficient demonstration that the DNSPs' UCA rates represent an efficient level of labour cost escalation, for the following reasons:

- Both UCAs[1248] came into effect prior to the global financial crisis (GFC)[1249] and therefore do not reflect the impact and uncertainty of GFC-associated economic conditions on labour growth. For similar reasons, the AER does not agree with Ergon Energy's claim that the wage outcomes under the current UCA are a reliable predictor of labour costs to the end of the next regulatory control period.[1250] The AER notes Access Economics' comments which indicate Queensland's underperformance in response to the economic downturn has begun to feed through to movements into utilities sector wages, with further weaknesses occurring in the first half of 2010 and data indicating reversion back to the norm may not occur until 2011.[1251] Further to this, the AER notes Access Economics' view that institution-based approaches (including UCAs) may assist in short term forecasting but are not necessarily appropriate for the longer term.[1252] The AER therefore considers updated data provides a better basis for forecasting the DNSPs' future labour costs than UCA rates established prior to the GFC.
- The AER considers that the outcomes from any specific wage negotiation do not necessarily reflect efficient labour costs for the industry as a whole. The AER notes PwC's comments pertaining to 'the market power enjoyed by unions and their ability to influence the demand for and supply of labour'.[1253] The AER disagrees with PwC's view that it has overemphasised the incentive issue discussed in the draft decision and that wage increases in the UCA should be considered a strong indicator of market conditions.[1254] The AER considers this point gives credibility to the argument that unions are in a position to inappropriately influence labour cost expectations within the electricity sector, as power lies with these unions to determine these costs which have no reflection on actual market conditions or state/territory economic performance.

1246 Energex, *Submission on draft determination,* February 2010, Appendix 2.0, p. 27; and Ergon Energy, *Revised regulatory proposal*, January 2010, pp. 87–89.

1247 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 89.

1248 Energex, Response to AER.EGX.27 – Labour cost, 5 October 2009, confidential; and Ergon Energy, Response to AER.ERG.RRP.30 –Union Collective Agreement/Cost Escalators, 11 March 2010.

1249 The AER notes a paper published by the Australian Government – The Treasury, *Australia's response to the global financial crisis,* www.treasury.gov.au, accessed 22 February 2010, stated the key turning point for the Australian economy was the change that swept through the global economy in mid–September 2008.

1250 Ergon Energy, *Revised regulatory proposal*, January 2010, p. 88.

1251 Access Economics, *Forecast growth in labour costs,* 16 March 2010, pp. 69–70.

1252 Access Economics, *Forecast growth in labour costs,* 16 March 2010, p. 114.

1253 Energex, *Submission on draft determination,* February 2010, Appendix 2.0, p. 28.

1254 Energex, *Submission on draft determination,* February 2010, Appendix 2.0, pp. 27, 29.

- The AER considers that state and territory specific labour cost escalators, based on the relevant industry classifications, better reflect the market conditions and economic performance of that particular state or territory than do national measures of wage growth.[1255]

Further to the above analysis, the AER requested additional information from the Qld DNSPs in order to determine whether their proposed internal labour escalators resulted in materially different capex and opex forecasts to those based on the AER's cost escalators. Information provided by Energex indicated that application of Energex's real internal labour escalators produced capex and opex impacts of approximately $136 million and $57 million respectively compared to capex and opex impacts of $77 million and $32 million respectively when the AER's escalation rates were applied.[1256]

Ergon Energy was unable to complete the AER's request to model the impacts of internal labour cost escalators on Ergon Energy's opex and capex. However, interim information provided by Ergon Energy indicated that the application of Ergon Energy's real internal and contract labour escalators (collectively) resulted in materially larger impacts than the application of the AER's escalators.[1257] Further to this, the AER anticipates that the impacts on Ergon Energy's capex and opex, when applying Ergon Energy's real internal labour escalators relative to the AER's escalators, would result in similar impacts to those estimated for Energex, given the similarity of Ergon Energy's internal labour escalators.

Based on these findings, together with the reasons outlined above, the AER considers that the UCA-based internal labour cost escalators proposed by the Qld DNSPs do not reflect reasonable and efficient internal labour costs that prudent operators in the circumstances of the Qld DNSPs would require to achieve the opex and capex objectives.

Weighted internal labour cost escalator

The AER notes that Ergon Energy did not adopt the AER's weightings for specialist and general labour in calculating a weighted internal labour cost escalator, on the basis that its UCA should apply equally to both types of labour.[1258] In response to a request by the AER, Ergon Energy advised its technical employees account for 73 per cent of all staff and the administrative, professional and management streams account for 27 per cent of staff.[1259] The AER does not consider it appropriate to apply one labour escalation rate to two different types of labour, given they reflect different industry classifications and therefore attract different wage rates. Therefore, the AER confirms the draft decision that it will apply a weighed average escalator to Ergon Energy's internal labour costs, reflecting the weightings advised by Ergon Energy.[1260]

[1255] This approach is consistent with that of the AER's NSW/ACT final determinations.
[1256] Energex, Response to AER follow-up question on modelling for the final decision, 13 April 2010, confidential.
[1257] Ergon Energy, Response to AER.ERG.RRP.02 – Cost escalator - Labour, 8 March 2010.
[1258] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 96.
[1259] Ergon Energy, Response to Q.AER.ERG.08.2 –Cost Escalators, 3 September 2009.
[1260] AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 614.

Different escalation rates for internal labour and external contractors

The AER notes that the Qld DNSPs considered that their UCA-based escalation rates for internal labour costs should be applied to contract labour costs.[1261]

The AER considers that internal labour cost escalators should not be applied to contract labour costs because:

- contractors do not form part of the internal, full-time or on-going workforce to which awards generally apply
- the proportions of technical and general labour in the internal and contract labour forces of a DNSP are likely to differ. For example, Ergon Energy advised that it considered all of its contract labour aligned with the definition of technical labour,[1262] whereas internal labour is approximately 73 per cent technical and 27 per cent general. For Energex, internal labour is approximately 95 per cent technical and 5 per cent general, whereas for contractors, these proportions are 79 per cent and 21 per cent respectively.[1263]
- contract labour engagements are generally short term fixed period contracts (not exceeding 12 months) which may attract a fixed price or schedule of rates.[1264] [1265]

The AER considers that UCA-based escalators should not be applied to contract labour costs for the same reasons, outlined above, that it considers these rates should not be applied to the Qld DNSPs' internal labour costs. As per the AER's analysis for internal labour, the AER requested additional information from the Qld DNSPs in order to determine whether their proposed contract labour escalators resulted in materially different capex and opex forecasts to those based on the AER's cost escalators. Information provided by Energex indicated that application of Energex's contract labour escalators produced capex and opex impacts of approximately $134 million and $67 million respectively compared to capex and opex impacts of $59 million and $30 million respectively when the AER's escalation rates were applied.[1266]

Ergon Energy was unable to complete the AER's request to model the impacts of contract labour cost escalators on Ergon Energy's opex and capex. However, interim information provided by Ergon Energy indicated that the application of Ergon Energy's real internal and contract labour escalators (collectively) resulted in

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1261 Energex, *Submission on Draft Determination*, February 2010, Appendix 2.0, p. 27; Ergon Energy, *Revised regulatory proposal*, January 2010, p. 85; and Ergon Energy, *Supplementary information – Ergon Energy's Regulatory proposal reference to UCA and contractor rates and AER.ERG.02*, 12 March 2010.

1262 Ergon Energy, Response to Q.AER.ERG.15.02 –Escalations –EDSD Allowance, 18 September 2009, confidential.

1263 Energex, Response to Q.AER.EGX.27 – Labour cos*t*, 3 September 2009, confidential and Energex, Response to Q.AER.EGX.14 – Cost escalators, 25 September 2009, confidential.

1264 Energex, Response to AER.EGX.RP.07 – Contract labour questions, 10 March 2010, confidential.

1265 Ergon Energy, Response to AER.ERG.RRP.27.1 –Cost Escalators – Labour, 5 March 2010, confidential.

1266 Energex, Response to AER follow-up question on modelling for the final decision, 13 April 2010, confidential.

materially larger impacts than the application of the AER's escalators.[1267] Further to this, the AER anticipates that the impacts on Ergon Energy's capex and opex, when applying Ergon Energy's real contract labour escalators relative to the AER's escalators, would result in similar impacts to those estimated for Energex, given the similarity of Ergon Energy's contract labour escalators.

AER conclusions on labour cost escalators

As a result of the above review and analysis, the AER does not consider the application of the labour escalation rates proposed by the Qld DNSPs for internal labour and contractors reflect reasonable and efficient costs.

For internal labour costs, the AER confirms its draft decision that it is reasonable to adopt the Qld DNSPs' actual UCA rates up until 2009–10.[1268] For the next regulatory control period, the AER considers it appropriate to apply updated EGW and general labour forecasts for Queensland to determine Energex's and Ergon Energy's weighted average internal labour escalator which will apply to their internal labour costs, based on the weights outlined in the draft decision.[1269]

For contract labour costs, the AER considers it appropriate to apply the updated Access Economics EGW and general labour growth forecasts for Queensland, as produced in March 2010, in deriving weighted average contract labour cost escalators for Energex, based on the weights outlined in the draft decision.[1270]

With respect to Ergon Energy's contract labour, as per the draft decision, the AER considers it appropriate to apply the updated Access Economics EGW growth forecasts for Queensland, as produced in March 2010, to determine its contract labour escalation rates.[1271]

The AER's conclusions on the DNSPs' internal and contract labour escalators are in table F.5.

For the reasons discussed, and as a result of the AER's consideration of the Qld DNSPs' revised regulatory proposals, submissions and other material, the AER is satisfied that the application of the updated internal labour and contract labour cost escalators to the Qld DNSPs' opex and capex results in expenditure which reasonably reflects the opex and capex criteria, including the opex and capex objectives. In coming to this view, the AER has had regard to the opex and capex factors.

[1267] Ergon Energy, Response to AER.ERG.RRP.02 – Cost escalator - Labour, 8 March 2010, confidential.

[1268] AER, *Draft decision, Queensland draft distribution determination,* November 2009, p. 613.

[1269] AER, *Draft decision, Queensland draft distribution determination,* November 2009, pp. 611 and 614.

[1270] AER, *Draft decision, Queensland draft distribution determination,* November 2009, p. 612.

[1271] AER, *Draft decision, Queensland draft distribution determination,* November 2009, p. 615.

F.5.2 Construction costs

The AER notes that the Qld DNSPs accepted the AER's approach to deriving construction cost escalators. They applied construction cost forecasts updated with the latest available data released from the CFC in November 2009.[1272]

The AER notes that the updated construction cost forecasts applied by the Qld DNSPs are based on the original price index,[1273] not the seasonally adjusted price index, as per the AER's draft determination and previous regulatory decisions.[1274] The AER considers seasonally adjusted estimates better reflect the current state of the market, as such estimates allow for and remove the regular and reoccurring influences that can distort the short term view of the market.[1275] Further, the AER is not satisfied the Qld DNSPs have provided sufficient justification to apply original estimates in lieu of seasonally adjusted price estimates. Therefore, for the purposes of this final decision, the AER has maintained the use of seasonally adjusted construction cost forecasts.

As foreshadowed in the draft decision, the AER considers that to develop a robust forecast it is appropriate to update the forecast construction cost escalators using the most recent data. The AER therefore considers it appropriate to apply the updated construction cost forecasts from CFC.[1276]

The AER, as per the draft decision[1277] and previous regulatory decisions[1278], considers it appropriate to deflate the updated construction cost forecasts using Econtech's Australian National State and Industry Outlook inflation forecasts to determine real forecasts. The AER's conclusions on the Qld DNSPs' real construction cost escalator are presented in table F.5.

For the reasons discussed, and as a result of the AER's consideration of the Qld DNSPs' revised regulatory proposal, PB's report and other material, the AER is satisfied that the application of the updated construction cost escalator to the Qld DNSPs' capex and opex forecasts results in expenditure which 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.

F.5.3 Materials

The AER notes the concerns raised by the Qld DNSPs in relation to using LME 63 month and 123 month contract prices to calculate escalation rates for aluminium

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1272 Energex, *Submission on Draft Determination*, February 2010, p. 7 and Ergon Energy, *Revised regulatory proposal*, January 2010, p. 139.

1273 Energex, Response to AER.EGX.RP.03 – Construction cost escalators, 26 February 2010, confidential; and Ergon Energy, Response to AER.ERG.RRP.31 – Cost escalators, 12 March 2010, confidential.

1274 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 599; and AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 497.

1275 The AER's view stems from definitions of seasonally adjusted estimates as published on the ABS website (www.abs.gov.au).

1276 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 599.

1277 AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 599.

1278 AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 497.

and copper. In response, the AER reviewed the LME price data it used in the draft decision.

The AER used official LME price data for futures contracts out to 27 months for aluminium and copper. LME's official prices reflect bids and offers made by market participants during the busiest trading session of the day (which is the second of four daily trading periods).

The AER has confirmed that the LME prices it used for 63 month and 123 month futures contracts were unofficial prices that were incorrectly taken to be official prices. The AER understands that these unofficial prices are evaluated prices which are established by the LME Quotations Committee using a fair value method. While these prices may reflect actual trades, the AER understands that they are established irrespective of whether any actual trades take place.[1279]

Given that LME prices for 63 month and 123 month futures contracts are unofficial and do not reflect price outcomes from a liquid market, the AER considers it inappropriate to use this data in preference to Consensus Economics long term forecasts. As a result, the AER accepts the proposal by the Qld DNSPs to use Consensus Economics long term forecasts to establish cost escalators for aluminium and copper.

The approaches to cost escalation proposed by the Qld DNSPs are based on the same underlying modelling approach by SKM, which included the use of the TWI.

The AER notes Ergon Energy's comments about the TWI and reviewed additional information provided by Ergon Energy regarding its use in SKM's model.[1280]

SKM sought to verify its cost escalation model by comparing model outputs with actual prices observed in its market price survey.[1281] SKM noted that because DNSPs import relatively little equipment, it was possible to compare model and price outcomes for only two types of equipment, namely circuit breakers and regulators. SKM claimed that this analysis confirmed that inclusion of the TWI as a factor in the model generally produces superior results and predictions of price movements.[1282]

The AER has a number of concerns with the inclusion of the TWI component in the cost escalation modelling undertaken by SKM.

First, the analysis provided by SKM was based on results for only two types of equipment. The AER does not consider that this was a sufficiently large sample from which to generalise for other types of imported equipment. In addition, the AER is concerned about the results for those two categories, given SKM's comment that

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1279 LME, *Response to AER question*, 3 February 2010, and LME, *Procedures for the establishment of LME closing prices at 17.00 hours*, LME web site, February 2010.

1280 Ergon Energy, Response to AER.ERG.RRP.19 – Cost escalators, 5 March 2010.

1281 Ergon Energy, Response to AER.ERG.RRP.19 – Cost escalators, *SKM Internal Memo,* 5 March 2010, p. 5.

1282 Ergon Energy, Response to AER.ERG.RRP.19 – Cost escalators, *SKM Internal Memo,* 5 March 2010, p. 5.

special contractual arrangements (for example, bulk purchases spread over a number of years) can affect the comparison to some extent.[1283]

The AER also notes SKM's statements that:

- in the absence of a recent publically available forecast developed by a reputable source, SKM has assumed a fixed value for the TWI[1284] [1285]

- if the TWI stays constant, the local and imported manufacturing escalators will be equal – that is, zero real cost escalation will apply.[1286] [1287]

The AER notes that, for the Qld DNSPs, the inclusion of the TWI in SKM's model results in the escalation of real materials costs prior to the commencement of the next regulatory control period. These impacts are maintained throughout the next regulatory control period as a result of the constant TWI assumption.[1288] [1289]

The AER does not consider it appropriate to allow for the escalation of real costs prior to a regulatory control period when there is no possibility that any cost decreases during the regulatory control period will be accounted for in the same way. To do so would introduce an asymmetric treatment of costs.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER considers that the method adopted by the Qld DNSPs with the exception of the TWI component, provides a realistic expectation of the real materials costs required for the Qld DNSPs to achieve the capex and opex objectives in the next regulatory control period.

As foreshadowed in the draft decision, the AER considers that to develop a robust forecast it is appropriate to update the forecast materials cost escalators using the most recent data.[1290] The AER considers that this and the removal of the TWI from SKM's modelling are the minimum adjustments necessary to ensure that the material cost escalators used by the Qld DNSPs to provide a realistic expectation of real material costs.

F.6 AER conclusion

Based on the most recent data at the time of this decision, the methodologies proposed by the Qld DNSPs in their revised regulatory proposals, and the AER adjustments

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1283 Ergon Energy, Response to AER.ERG.RRP.19 – Cost escalators, *SKM Internal Memo,* 5 March 2010, p. 5.

1284 Ergon Energy, Response to AER.ERG.RRP.19 – Cost escalators, SKM Internal Memo, 5 March 2010, p. 3.

1285 Energex, *Submission on Draft Determination,* February 2010, Appendix 1.0 – Energex materials and cost escalation forecasts for 2010-15, Sinclair Knight Merz, p. 22.

1286 Ergon Energy, Response to AER.ERG.RRP.19 – Cost escalators, SKM Internal Memo, 5 March 2010, p. 3.

1287 Energex, *Submission on Draft Determination,* February 2010, Appendix 1.0, pp. 22–23.

1288 Ergon Energy, Response to AER.ERG.RRP.19 – Cost escalators, SKM Internal Memo, 5 March 2010, p. 4.

1289 Energex, *Submission on Draft Determination,* February 2010, Appendix 1.0, p. 23.

1290 AER, *Draft decision*, *South Australian draft distribution determination 2010–11 to 2014–15*, 25 November 2009, p. 458.

discussed above, the AER's conclusions on real cost escalators for this final decision are presented in table F.5. The AER requested Energex to update its composite materials cost escalator to reflect the updated material cost inputs. These composite materials cost escalation rates are also presented in the table F.5.

Table F.5: AER conclusion on real cost escalators for Energex and Ergon Energy (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Escalators applying to both DNSPs							
Aluminium	–18.76	–6.96	23.00	–1.20	0.40	–2.62	–3.58
Copper	–27.33	17.42	20.03	–5.42	–4.19	–7.48	–8.63
Steel	7.09	–28.29	33.03	1.00	0.80	–2.29	–3.25
Crude oil	–17.34	–3.69	25.80	–2.97	0.24	–1.74	–2.46
Exchange rates	0.744	0.856	0.721	0.738	0.725	0.728	0.738
Inflation rate	1.46	3.00	2.50	2.75	2.50	2.50	2.50
Energex							
Materials[a]	–5.05	–5.31	10.71	–0.42	0.11	–1.20	–1.67
Land and easements	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Construction	–0.09	1.90	0.31	1.10	2.66	2.51	0.81
Internal labour	0.12	2.22	0.20	0.86	1.27	1.52	1.63
Contract labour	0.99	0.97	0.83	0.78	1.22	1.50	1.61
Ergon Energy							
Commercial land	4.20	5.50	5.40	5.00	5.00	5.40	5.80
Rural land	6.80	8.10	8.00	7.60	7.60	8.00	8.40
Construction	–0.09	1.90	0.31	1.10	2.66	2.51	0.81
Internal labour	0.18	1.83	0.21	0.75	1.19	1.50	1.60
Contract labour	1.15	1.08	0.98	0.88	1.29	1.53	1.64

Source: AER analysis.
(a) Energex's materials cost escalator is a composite based on materials inputs listed in this table. Source: Energex, Response to AER modelling request (Energex FD), 9 April 2010, confidential.

G. Benchmarking

Benchmarking can be defined as a process of comparison of some measure of actual performance against a reference or benchmark.[1291] This appendix sets out the AER's consideration of benchmarking issues that have been raised in the concurrent distribution determination processes for ETSA Utilities and Energex and Ergon Energy (the Qld DNSPs).

G.1 Rule requirements

DNSPs are required to provide a forecast of the total opex required over the regulatory control period in order to achieve the opex objectives:[1292]

> (1) meet or manage the expected demand for standard control services over that period;
>
> (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
>
> (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.

If the AER is satisfied that the total forecast opex for the regulatory control period reasonably reflects the opex criteria, then the AER must accept the forecast of the required opex. The opex criteria require that the total of the opex forecast reasonably reflects:[1293]

> (1) the efficient costs of achieving the operating expenditure objectives; and
>
> (2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In deciding whether or not the AER is satisfied the opex forecast reasonably reflects the opex criteria it must have regard to the opex factors, including:[1294]

> (4) benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period.

The capex opjectives, capex criteria, and the capex factors mirror those of opex, and are set out in clauses 6.5.7(a), 6.5.7(c) and 6.5.7(e) of the NER.

[1291] Mehdi, F., Fetz, A., Fillipini, M., *Benchmarking and regulation in the electricity distribution sector*, Centre for Energy Policy and Economics, Swiss Federal Institute of Technology, p. 7.
[1292] NER, clause 6.5.6(a).
[1293] NER, clause 6.5.6(c).
[1294] NER, clause 6.5.6(e).

G.2 AER draft decision

Capex

To review the forecast capex allowances of the Qld DNSPs and ETSA Utilities the AER undertook capex ratio analysis, using data (where available) for years 2006–07 to 2014–15. This ratio analysis was provided to PB and included graphs illustrating the relative position over time, for a variety of ratios, of ETSA Utilities and the Qld DNSPs, as well as comparable DNSPs (such as Country Energy for Ergon Energy). The ratios used were:[1295]

- capex/RAB
- non–system capex/customers
- non–system capex/line length
- non–system capex/maximum demand
- non–system capex/energy consumption.

This top down analysis of the DNSPs allowed the AER to consider their spending per unit of various cost drivers (for example, viewing a DNSP's spend on non–system capex per MW of maximum demand). The capex ratio analysis compared DNSPs' forecast capex for the next regulatory control period, and the AER had regard to that analysis in determining which elements of the capex forecast to subject to greater scrutiny. The AER considered its development and use of the capex ratio analysis addressed the benchmarking requirements of clause 6.5.7(e)(4) of the NER, as well as helping to determine the costs of a prudent and efficient operator in the circumstances of the relevant DNSP.

The AER also reviewed information on unit costs[1296] and comparisons of proposed capex to annual capex, prepared for each DNSP by PB. The AER considered advice from PB on whether or not the methods used to estimate unit costs were robust and consistent. The AER is satisfied that in each case the bottom up evaluation of each DNSP's unit costs demonstrated the costs to be comparable to those of other electricity NSPs, and are efficient.[1297] The AER also considers that as DNSPs are subject to commercial incentives, using previous costs to inform an assessment of costs going forward is a reasonable way of establishing what efficient costs should be.

The AER considered it addressed the requirements of clause 6.5.7(e)(4) of the NER.

[1295] AER, internal analysis.

[1296] Depending on the DNSP unit costs were provided for a wide range of things such as circuit breakers, particular voltage lines or a zone substation.

[1297] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 120–121; and AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 100.

Opex

Ratio analysis

The AER conducted a ratio analysis for a variety of ratios, which compared forecast opex over the next regulatory control period with actual and forecast opex from 2007–08. This analysis was made available to PB for it to consider as part of its reports on the Qld DNSPs and ETSA Utilities.[1298] The ratio analysis utilised simple and normalised ratios, such as:

- opex/line length
- opex/customers
- opex/RAB
- opex/energy consumption
- opex/maximum demand
- opex per kilometre/energy consumption per kilometre
- opex per kilometre/RAB per kilometre
- opex per kilometre/customers per kilometre
- opex per kilometre/maximum demand per kilometre.

The opex ratio analysis compared DNSPs' forecast opex for the next regulatory control period, and the AER had regard to that analysis in determining which elements of the opex forecast to subject to greater scrutiny.

Regression analysis

The AER also undertook regression analysis, which was conducted using actual data from 2007–08.[1299] This analysis was informed by benchmarking work that has been undertaken by Ofgem in the United Kingdom, and by Wilson Cook for the AER.[1300] It is an extension of the studies that were conducted for the ACT and NSW distribution determinations. The AER recognises that the work has yet to benefit from wider consultation with technical experts.

[1298] PB, *Report – ETSA Utilities*, October 2009, p. 22 and pp. 163–166; PB, *Report – Ergon Energy*, October 2009, p. 28 and pp. 141–143; and PB, *Report – Energex*, October 2009, pp. 22–23 and pp. 117–119.

[1299] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 624–626 and pp. 659–662; and AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 199–201.

[1300] Wilson Cook, *Review of proposed expenditure of ACT & NSW electricity DNSPs: Volume 1, Main Report*, October 2008, pp. 17–25; and Wilson Cook, *Review of proposed expenditure of NSW & ACT electricity DNSPs: EnergyAustralia's submissions of January and February 2009*, March 2009, pp. 13–15.

To improve the statistical reliability of the analysis, some variables that were considered important cost drivers (such as energy delivered) were omitted on the basis of multicollinearity. Despite the effect of multicollinearity on the significance of the estimators, if the omitted cost drivers have an effect on the dependent variable then they should be included in the model, or else the model may be biased.[1301]

In addition to this, the rationale behind selecting the model over others was based largely on which had the 'best' R^2 term. Experimenting with different models in such a way and choosing one which appears to have the best fit without a firm theoretical basis is not, however, viewed as a sound econometric practice.[1302] The model also does not take into account any capex/opex tradeoffs.[1303] In this analysis, when benchmarking Ergon Energy, a regression was conducted on only rural DNSPs, which further reduced an already small sample size. Lastly, while the 'combined scale variable' constructed by Wilson Cook attempts to compare all firms on the basis of size, it does not take into account a large number of operating conditions such as load density or topography.

The AER also considered benchmarking work undertaken by consultants on behalf of the Qld DNSPs.[1304]

Summary

The AER concluded, on the basis of its top down analysis, that Energex and ETSA Utilities appeared relatively efficient compared to other DNSPs, while Ergon Energy appeared to have higher costs than comparable DNSPs.[1305] The AER identified a number of reasons that may explain the variation in each DNSP's costs that would not have been captured by this particular form of analysis.[1306] The AER considered the opex ratio analysis and regression analysis addressed the benchmarking requirements of clauses 6.5.6(e)(4) of the NER, as well as helping to establish what costs a prudent operator in the circumstances of each DNSP would incur.[1307]

The AER's review of opex also included a bottom up review of proposed opex, informed by a report from PB. To ensure that the DNSPs will incur only efficient expenditure the AER, and its consultant PB, reviewed the efficiency of labour and material costs used to forecast expenditures and the efficiency of the forecast opex for each year of the next regulatory control period.[1308] The AER considers that as the DNSPs are subject to commercial incentives, where a DNSP is observed to be operating prudently then audited base year unit costs can be regarded as efficient. The application of the EBSS ensures that there is a constant incentive for DNSPs to reduce

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[1301] Wooldridge, J. M., *Introductory Econometrics*, 4th Edition, 2009, pp. 96–99.
[1302] Wooldridge, J. M., *Introductory Econometrics*, 4th Edition, 2009, p. 677.
[1303] More discussion of this can be found below.
[1304] AER, *Draft decision, Queensland draft distribution determination*, November 2009, appendix I, pp. 624–625 and pp. 659–660.
[1305] The AER's analysis of Ergon Energy in this instance compared Ergon Energy only to other DNSPs operating in a regional environment.
[1306] AER, *Draft decision, Queensland draft distribution determination*, November 2009, appendix I, p. 660; and AER, *Draft decision, SA draft distribution determination*, November 2009, p. 199.
[1307] Subject to the limitations as discussed in this appendix.
[1308] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 144–145; and AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 178–179.

costs. Appropriately designed scale escalators applied to prudent base year costs can then be used as reasonable comparators. The AER considers that this revealed cost approach is effective in ensuring that firms continually move towards an efficient standard of performance.

The AER considered it addressed the requirements of clause 6.5.6(e)(4) of the NER.

G.3 Submissions

The Energy Consumers Coalition of South Australia (ECCSA), the Energy Users Association of Australia (EUAA), Cement Australia and EnergyAustralia made submissions regarding benchmarking.

ECCSA stated in a submission that benchmarking 'is a core element of the implicit requirement of regulation'.[1309] ECCSA considered that benchmark analysis has a role to play in setting opex allowances, however, it acknowledges that there are a number of drawbacks to its use. ECCSA remarked on the use of total factor productivity as one particular benchmarking approach that may have some application.

The EUAA submitted a detailed appraisal of the benchmarking that was contained in the draft decisions. The EUAA stated that no benchmarking was done for capex.[1310] It also stated that the benchmarking in relation to opex was inadequate as the AER:[1311]

- defined a role for benchmarking that is inconsistent with the rules
- failed to define the benchmark efficient opex
- benchmarked historic expenditure
- failed to act on the outcome of its benchmarking.

The EUAA estimated a reduction of 44 per cent and 38 per cent to Energex's and Ergon Energy's respective average annual total opex allowed in the draft decision.[1312] The EUAA also estimated a reduction of 27 per cent of ETSA Utilities' average annual revenue allowed in the draft decision.[1313]

Cement Australia stated that it was concerned that the AER use benchmarking to help establish an efficient level of networking costs.[1314]

EnergyAustralia supported the idea that the AER utilise benchmarking to test the reasonableness of a DNSP's expenditure proposals, and not directly to set expenditure allowances. EnergyAustralia considered that benchmarking can be a useful indicator of the general level of efficiency of DNSPs. However, it raised concerns that the AER is continuing to adopt analysis based on that of Wilson Cook during the NSW

[1309] ECCSA, *A response*, February 2010, p. 29.
[1310] EUAA, *Submission to the AER on QLD DNSPs*, February 2010, p. 19.
[1311] EUAA, *Submission to the AER*, February 2010, p. 25
[1312] EUAA, *Submission to the AER*, February 2010, p. 28.
[1313] EUAA, *Submission to the AER*, February 2010, p. 29.
[1314] Cement Australia, *AER review of electricity distribution prices in Queensland*, 16 February, p. 3.

distribution determination process. EnergyAustralia considered that in order to obtain meaningful benchmark comparisons, the AER's analysis needs to be more granular and examine data from several perspectives.[1315]

G.4 Revised Regulatory Proposals

Ergon Energy provided two reports from consultants addressing the issue of benchmarking:

- Benchmark Economics remarked on the consistency of data used in PB's models, the selection of cost drivers, the lack of statistical assessment of possible parameters, data selection, inconsistency of outcomes between models, the chosen 'efficiency frontier', and the use of a composite scale variable. Benchmark Economics also noted an apparent misinterpretation by the AER of material provided with Ergon Energy's regulatory proposal.[1316]

- Huegin Consulting Group (Huegin) reviewed certain aspects of the AER's benchmarking analysis. Huegin took issue with:[1317]

  - the AER's statement of 'relatively efficient'
  - the sampling process for the AER's and PB's analysis
  - the selection of the composite variable for the regression analysis
  - the interpretation of the model.

G.5 Issues and AER considerations

Rules requirements

The AER considers that its obligations under the NER in regard to determining total opex and capex allowances are clear. The AER must be satisfied that the total of the forecast expenditure proposed by DNSPs reflects the opex/capex criteria. Included in this is a consideration of the efficient costs of achieving the opex/capex objectives, a consideration of the costs a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex/capex objectives, and a consideration of the demand forecast and cost inputs required to achieve the opex/capex objectives.

If the AER is not satisfied that the total of the forecast expenditure (opex or capex) proposed by the DNSPs reflects the opex/capex criteria, then it must substitute an amount that the AER is satisfied reasonably reflects the opex/capex criteria taking into account the opex/capex factors.[1318] While the AER must have regard to the benchmark expenditure that would be incurred by an efficient DNSP over the

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[1315] EnergyAustralia, *EnergyAustralia submission on AER draft determinations for Queensland and South Australia*, 16 February 2010, pp. 1–5.
[1316] Benchmark Economics, *Ergon Energy Review of Benchmarking: AER review of capital and operating expenditure forecasts*, December 2009, pp. 1–27.
[1317] Huegin Consulting Group, *Review of Qld draft determination and Parsons Brickerhoff report on Ergon Energy's regulatory proposal*, January 2010, pp. 69–73.
[1318] NER, clauses 6.12.1(3) and 6.12.1(4)

regulatory control period (as well as the other opex/capex factors), the AER must assess whether the estimate reflects the opex/capex criteria. This means the AER must acknowledge (among other things) the actual circumstances of the business in question. The AER considers it may not solely assess or determine an estimate of opex or capex based on what it has judged to be benchmark expenditure that would be incurred by an efficient DNSP. The AER assesses and determines estimates based on a number of approaches, and in particular uses comparative cost analysis to ensure that the requirements of the NER are fulfilled.

Responses to submissions

The AER defined a role for benchmarking that is inconsistent with the rules

The AER does not consider that it has defined a role for benchmarking that is inconsistent with the rules, as the EUAA asserted. The AER acknowledges that the NER requires the AER to have regard to the benchmark opex and capex that would be incurred by an efficient DNSP over the regulatory control period. As the AER conducted benchmarking analysis, been informed by the benchmarking analysis of its consultant PB, and been informed by consultants' reports regarding benchmarking submitted by DNSPs, the AER considers that it has had regard to this factor when coming to its conclusions on the opex and capex allowances. Benchmarking was one component of the AER's comparative analysis.

The AER does not come to a separate view on each and every opex and capex factor in isolation. Rather, the AER considers all the opex/capex factors and takes a holistic approach to determining reasonable forecasts of opex/capex over the regulatory control period that reflect the opex/capex criteria. The AER considers that as the NER requires the AER to have regard to all opex/capex factors when determining whether it is satisfied that proposed expenditure reflects the opex/capex criteria, the AER must use its discretion when determining how much weight to place on each of those factors. There is no sensible objective metric by which the AER can give each opex/capex factor 'equal' importance.

The AER has failed to define the benchmark efficient opex

The AER considers that when benchmarking, all statements regarding efficiency are made relative to a reference or benchmark performance. The EUAA appears to be calling on the AER to explicitly define an efficient level of opex or capex relative to some operating condition or scale variable. The AER has not identified a single metric to use in isolation, but has used a variety of different measures that can be interpreted according to their advantages and limitations. The AER has considered a number of operating conditions (through its ratio analysis), scale variables (through its opex regression analysis and ratio analysis) and business costs (unit cost assessments), and made judgements of the relative efficiency of ETSA Utilities and the Qld DNSPs based on these considerations. This comparative analysis is a legitimate form of establishing efficient cost estimates for firms.

In each of these exercises (the ratio analysis, the regression analysis, and the various unit cost assessments) there is an implicit assumption that the most efficient firm will be the lowest cost firm for each measure. The AER has not explicitly pointed this out in each case, and does not consider it necessary to do so. The AER has further approached these measures with caution given that the data available for many of these measures is not necessarily gathered on a like-for-like basis, and each of these measures in isolation gives no indication as to whether there are likely to be substitution effects between various expenditure categories.

The AER has benchmarked historic expenditure

The EUAA stated that the AER has benchmarked expenditure using actual data from 2007–08, rather than benchmarking the proposed expenditure for the next regulatory control period.[1319] This issue is also touched on in the Benchmark Economics report provided by Ergon Energy.[1320] The AER considers that as expenditure over the next regulatory control period is not available for many of the Australian DNSPs on a like-for-like basis, a robust regression analysis based solely on forecast expenditure is infeasible. The 2007–08 data was the latest audited data available for the DNSPs.

The regression analysis of opex was not the only benchmarking that the AER conducted. The AER also conducted a ratio analysis for both capex and opex that was provided to its consultant PB. PB considered the outcomes of the AER's benchmarking work and reported on it.[1321] This ratio analysis took into account the proposed expenditure of ETSA Utilities and the Qld DNSPs over the next regulatory control period.

The AER complemented this work with a detailed bottom up analysis of proposed expenditure. The AER considers it has addressed the requirements of clauses 6.5.6(e)(4) and 6.5.7(e)(4) of the NER.

The AER has failed to act on the outcome of its benchmarking

The EUAA submitted that the AER has failed to act on the outcome of its benchmarking. The EUAA stated that (in reference to the AER's opex regression analysis) although the AER assessed Ergon Energy to appear less efficient than other firms in the sample, and Energex appeared more efficient, the AER made no changes to its allowed opex to account for this.[1322]

The AER conducted bottom up assessment of the Qld DNSPs and this bottom up assessment was guided by the ratio analysis and regression analysis. In particular PB considered this information before finalising its proposed in depth bottom up assessment of each DNSP's opex (and capex) proposals. The outcomes of the benchmarking undertaken by the AER have therefore directly impacted on the adjustments made to the opex and capex forecasts proposed by the DNSPs. Where a DNSP could not justify its regulatory proposal to the extent necessary, as determined by the AER's comparative analysis and detailed assessment, adjustments were made accordingly.

[1319] EUAA, *Submission to the AER on QLD DNSPs*, February 2010, p. 26.
[1320] Benchmark Economics, *Ergon Energy Review of Benchmarking: AER review of capital and operating expenditure forecasts*, December 2009, pp. 19–20.
[1321] PB, *Report – ETSA Utilities*, October 2009, p. 22 and pp. 163–166; PB, *Report – Ergon Energy*, October 2009, p. 28 and pp. 141–143; and PB, *Report – Energex*, October 2009, pp. 22–23 and pp. 117–119.
[1322] EUAA, *Submission to the AER on QLD DNSPs*, February 2010, p. 27.

Opex reductions

The AER notes that the EUAA has estimated opex reductions for ETSA Utilities and the Qld DNSPs, based on the derivation of an opex benchmark using the regression model applied by the AER.

The estimated percentage reduction that would need to be applied to the opex forecasts in the revised regulatory proposals are shown in table G.1.

Table G.1: Average annual opex forecast ($m, 2009–10)

	ETSA Utilities	Energex	Ergon Energy
EUAA benchmark opex	153	196	168
Revised regulatory proposal opex forecast	235	323	379
Difference	82 (35%)	323 (39%)	379 (56%)

Source: AER analysis; and EUAA, *Benchmarking and AER electricity network determinations*: appendix, January 2010.

The AER has considered the information provided by the EUAA, but has decided not to apply a further reduction to the forecast opex to reflect the EUAA's estimate of benchmark opex. The AER considers that applying a further reduction will lead to an outcome that does not reasonably reflect the opex criteria. Further, as discussed below, the limitations of benchmarking reduce confidence in the accuracy of this estimated benchmark opex. In particular there are issues around the relevance of the underlying model, and issues around the consistency of the data between businesses, that limit the use of the estimated benchmark opex.

However the AER does note that for all three DNSPs under consideration the EUAA's analysis adds further support to the reductions to opex estimated on the basis of the bottom up review.

Other issues

The EUAA also observed that the ordinary least squares (OLS) regression conducted by the AER shows the line of best fit intercepting the x–axis at a positive intercept.[1323] The EUAA considered that this contributes to the implausibility of the regression line as an efficiency frontier, because it can be interpreted as showing that a business with customers should incur zero costs. The AER does not consider this a material issue. In any regression, interpretation of the behaviour of the regression line around the intercepts is to be treated with caution.[1324]

The EUAA further submitted that a line of best fit obtained by OLS regression should not qualify as an efficiency frontier.[1325] The AER has not taken, and has never characterized the OLS regression line to be an efficiency frontier, but has used the line of best fit to observe the relative position of firms when compared using the

[1323] EUAA, *Benchmarking and AER electricity network determinations: appendix*, January 2010, p. 3.
[1324] Gujarati, D.N., *Essentials of Econometrics*, Third Edition, 2006, pp. 149–150
[1325] EUAA, *Benchmarking and AER electricity network determinations: appendix*, January 2010, p. 3.

combined scale variable ('size').[1326] The AER made the observation, for each DNSP, that the analysis took into account factors such as the relative size of each network. There are, however, other factors that may account for a DNSP's position relative to the regression line.[1327]

Benchmark Economics noted some success criteria which may be used to evaluate benchmarking models, where more than one model has been studied. These criteria are for businesses to rank in approximately the same order, for the same businesses to rank as 'efficient' or 'inefficient' across the different models, and for reasonable stability in the ranking of businesses over time.[1328] The AER considers these criteria are useful and as part of further work on benchmarking will consider similar criteria when assessing benchmarking models.

Benchmark Economics also commented on the cost drivers chosen by the AER and PB.[1329] Benchmark Economics stated that there was a lack of justification given for the choice of cost drivers, these being customer numbers and line length. Benchmark Economics suggested that rather than looking at what it terms 'scale variables', more telling analysis could be provided by looking closer at what it terms 'operating condition variables'. Operating condition variables would consist of measures such as energy density (MWh/km) or connection density (connections/km).[1330] The AER considers that such variables may also be influential cost drivers for DNSPs, and subject to data availability will consider these measures alongside others in further reviews of benchmarking approaches.

The AER notes the submissions from ECCSA and Cement Australia and considers its detailed response to the EUAA submission also addresses the concerns of ECCSA and Cement Australia.

The AER also notes EnergyAustralia does not support the use of benchmarking to directly specify expenditure allowances but considers it provides a useful indicator of the general level of efficiency of a DNSP.

Summary

The AER recognises that it is required to have regard to benchmark expenditure (opex and capex) that would be incurred by an efficient DNSP over the regulatory control period.

The AER also notes that in considering the opex and capex factors, it becomes a matter of judgement as to the weighting given to the factors. It is not possible to view

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[1326] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 624–626 and pp. 659–662; and AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 199–201.

[1327] AER, *Draft decision, Queensland draft distribution determination*, November 2009, appendix I, p. 660; and AER, *Draft decision, SA draft distribution determination*, November 2009, p. 199.

[1328] Benchmark Economics, *Ergon Energy Review of Benchmarking: AER review of capital and operating expenditure forecasts*, December 2009, p. 8.

[1329] Benchmark Economics, *Ergon Energy Review of Benchmarking: AER review of capital and operating expenditure forecasts*, December 2009, pp. 14–16.

[1330] Benchmark Economics, *Ergon Energy Review of Benchmarking: AER review of capital and operating expenditure forecasts*, December 2009, pp. 14–16.

and come to a conclusion on each of the opex and capex factors in isolation. The AER considers all the opex and capex factors, and makes judgements based on a holistic approach.

The AER must come to a conclusion on the allowance to be given for opex and capex that is specific to each DNSP, taking into account benchmark costs that would be incurred by an efficient DNSP. The AER considers that, in conjunction with clauses 6.5.6(c)(2) and 6.5.7(c)(2) it must therefore have regard to a DNSP's circumstances as well as any established benchmark costs. When considering the allowance for each DNSP, the opex and capex factors do not stand alone but are considered together.

The AER considers that it cannot establish revenue allowances based primarily on the outcome of comparative benchmarking against other firms, as seems to be the EUAA's preferred approach.[1331] Where more standardised and appropriate data is available and benchmarking models give more consistent results, the weighting given to top down benchmarking as a part of the AER's comparative analysis will likely increase.

However, in addition to the overarching regulatory framework and requirements of the NER under which the AER operates, there are inherent limitations in benchmarking techniques which must be recognised.

Limitations of benchmarking

Benchmarking techniques require operating conditions to be accounted for so as to make firms directly comparable.[1332] Australian electricity DNSPs face a diverse range of operating environments, and have widely varied customer bases, jurisdictional requirements and cost drivers. The AER does not yet have access to the depth of data required to perform detailed benchmarking analysis that will normalise firms to make them directly comparable. The AER considers that it will need data that is reported in a standardised and comparable format to be able to undertake meaningful benchmarking. Currently the information that the AER receives from DNSPs is not homogeneous enough to produce a benchmarking model that would withstand statistical testing.[1333] The top down benchmarking work that has been conducted by the AER has nevertheless been useful as test of the conclusions of its detailed bottom up assessments, and the AER has considered this analysis.

In most benchmarking models, where a firm appears less efficient than its peers, it will be unclear whether this difference is due to real inefficiency, data noise or a failure of the model to account for some firm-specific factor.[1334] In order to minimise this problem high quality data will be needed. The AER considers that it does not currently have access to sufficient data to enable it to rely on benchmarking outcomes to set or amend opex and capex allowances directly.

[1331] EUAA, *Benchmarking and AER electricity network determinations: appendix*, January 2010, p. 1.

[1332] Shuttleworth, G, Benchmarking of electricity networks: Practical problems with its use for regulation, *Utilities Policy 13*, 2005, p. 311.

[1333] As a result of differing business circumstances and having developed under differing regulatory regimes, DNSPs currently have varied cost allocation and accounting policies.

[1334] Shuttleworth, G, Benchmarking of electricity networks: Practical problems with its use for regulation, *Utilities Policy 13*, 2005, p. 316.

In the move from a state based regulatory framework to a national framework some differences in jurisdictional requirements remain. For example, DNSPs differ in their capitalisation, cost allocation and accounting policies. The AER considers that accounting and reporting practices that enable DNSPs to provide more directly comparable cost data would be beneficial, however, implementing these will take some time. The lack of standardised reporting to date limits the AER's ability to develop robust statistical models.

The AER also recognises that different benchmarking techniques reach different conclusions. Whichever approach the AER chooses, there will exist examples of other justifiable approaches that yield different conclusions. There is an element of arbitrariness in model choice that will always be open for criticism.[1335]

The choice of what outputs should be benchmarked underpins any modelling. The number of outputs which can be modelled will be restricted by the size of the comparator group.[1336] Many benchmarking techniques define outputs such as length of line, number of customers, connection density or peak demand, and treat these outputs as exogenous. When these cost drivers are modelled separately (such as non-system capex vs line length, and non-system capex vs customer numbers) they can produce non-conforming results.[1337] The AER considers that a benchmarking model that utilises units of energy delivered or peak demand as an exogenous output may act to limit any incentive for a DNSP to put in place effective demand management systems.[1338] The quality of service could also be treated as an output, in order to capture the trade–off between service reliability and cost.[1339]

It may be possible to increase the size of the comparator group by including international firms in the analysis. However, this results in a far greater level of complexity. It increases the data gathering requirements, and increases the level of 'cleaning' that needs to be done on the data in order to ensure that the information gathered is on a 'like-for-like' basis. Introducing international comparators may not necessarily result in a better benchmarking model, although it will increase the difficulty of creating a model.[1340]

Benchmarking total capex, especially over short periods of time, can be difficult, where the lumpiness of capex programs can impact on results. Firm-specific factors that are unaccounted for in a model may appear as inefficiency where this is not the case. Non–system capex is generally less lumpy and therefore better suited to benchmarking.

[1335] Mehdi, F., Fetz, A., Fillipini, M., *Benchmarking and regulation in the electricity distribution sector*, Centre for Energy Policy and Economics, Swiss Federal Institute of Technology, pp. 12–13; and Shuttleworth, G, Benchmarking of electricity networks: Practical problems with its use for regulation, *Utilities Policy 13*, 2005, p. 316.

[1336] Shuttleworth, G, Benchmarking of electricity networks: Practical problems with its use for regulation, *Utilities Policy 13*, 2005, p. 312.

[1337] AER, internal analysis.

[1338] This depends on the cost elasticity of demand management.

[1339] Pollitt, M, The role of efficiency estimates in regulatory price reviews: Ofgem's approach to benchmarking electricity networks, *Utilities Policy 13*, 2005, pp. 286–287.

[1340] Shuttleworth, G, Benchmarking of electricity networks: Practical problems with its use for regulation, *Utilities Policy 13*, 2005, p. 313.

Different licensing requirements can make a large difference in a business' required system capex spend. For example, mandatory system security standards will vary from state to state. There are also differences in whether businesses buy or lease assets, and differences in balance dates, all of which can make benchmarking more problematic.

Benchmarking capex and opex separately may also lead to problems where trade–offs between capex and opex are not accounted for in the models.[1341] The benchmarking of total expenditure is possible, however under the NER the AER considers that it is required to benchmark capex and opex separately.

Future directions

The submissions on the AER's and PB's benchmarking work provided by the EUAA, EnergyAustralia and Ergon Energy (Benchmark Economics and Huegin Consulting Group) have all stated ways in which the AER's benchmarking could be improved. However, the submissions also stated a number of different methods by which these improvements could be brought about, and have in some cases provided a different picture of which firms may be classed as efficient and inefficient. Although some regulatory bodies in the international sphere rely heavily on benchmarking to set allowances (such as Ofgem in the United Kingdom), the AER notes that their methods are still being refined and they have had a longer period to develop consistent data sets. Even so, their methods are not free from controversy.[1342] The AER considers that while it intends to review its benchmarking, at this stage the quality and amount of data does not lend itself to an unambiguous interpretation of any one benchmarking model. A more detailed benchmarking exercise, such as that called for in some submissions, will require more standardised data from DNSPs, and over a longer time scale than the AER can currently access. Where further data over a longer time period is available, the AER will be able to utilise benchmarking to a greater degree.

The AER has had regard to benchmarking and weighted its interpretation of its models with suitable caution, given the current limitations. However, at this stage the AER considers it is appropriate to use top down benchmarking as a 'sense check' of more detailed bottom up conclusions. The use of benchmarking in this way has support in academic literature. The AER does not stand alone in its consideration that the use of benchmarking can not fully replace a detailed investigation of costs.[1343]

As the AER works to improve its benchmarking models, it will continue its dialogue with stakeholders to construct models which can account for each DNSP's specific cost drivers more effectively, and to gather the appropriate data for a more detailed exercise.

[1341] Shuttleworth, G, *Regulatory benchmarking: A way forward or a dead-end?*, NERA Newsletter, October 1999, pp. 1–2; and Jamasb, T. and M. Pollitt, Incentive regulation of electricity distribution networks: Lessons of experience from Britain, *Energy Policy 35*, 2007, p. 21.

[1342] Shuttleworth, G, *Regulatory benchmarking: A way forward or a dead-end?*, NERA Newsletter, October 1999, pp. 2–3; and Jamasb, T. and M. Pollitt, Incentive regulation of electricity distribution networks: Lessons of experience from Britain, *Energy Policy 35*, 2007, p. 26.

[1343] Shuttleworth, G, Benchmarking of electricity networks: Practical problems with its use for regulation, *Utilities Policy 13*, 2005, p. 317.

G.6 AER conclusion

The AER considers that it has had regard to benchmarking, and utilised the information gained from its models in a suitable manner considering the limitations imposed by the current data.

As required under clauses 6.5.6(e) and 6.5.7(e) of the NER, the AER has had regard to benchmark expenditure (opex and capex) that would be incurred by an efficient DNSP over the regulatory control period in coming to its conclusions on the forecast opex and capex allowances of the Qld DNSPs and ETSA Utilities. The AER will continue to develop more robust benchmarking techniques, and improve the quality of available information in order to expand its usage of benchmarking in evaluating opex and capex proposals.

H. Self insurance

This appendix sets out the AER's assessment of the Qld DNSPs' self insurance allowances in their opex forecasts for the next regulatory control period.

H.1 AER draft decision

H.1.1 Energex

The draft decision for Energex's proposed self insurance allowance is shown in table H.1.

Table H.1: AER draft conclusion on Energex's self insurance opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Energex regulatory proposal						
Storm catastrophe	1.6	1.6	1.8	1.9	1.6	8.5
Public liability	1.2	1.3	1.3	1.3	1.4	6.5
Retailer credit risk	0.085	0.08	0.07	0.07	0.06	0.36
Total self insurance	2.9	3.0	3.2	3.3	3.1	15.6
AER draft decision						
Storm catastrophe	0	0	0	0	0	0
Public liability	0.008	0.008	0.008	0.008	0.008	0.04
Retailer credit risk	0	0	0	0	0	0
AER approved self insurance allowance	.008	.008	.008	.008	.008	.04

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 712.
Note: Totals may not add due to rounding.

The AER assessed Energex's self insurance proposal against the following five principles:[1344]

- 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

[1344] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 694–699.

- whether a self insurance premium can be determined and whether the self insurance event relates to an incurred cost
- whether the premium estimated is an efficient cost.

Storm catastrophe

The AER did not accept Energex's proposed self insurance allowance for storm catastrophe. The AER considered that these risks were better managed, if material, via the cost pass through mechanism. In addition, the AER considered that non–material storm damage could be met through a prudent reprioritisation of the opex and capex allowances as expediency dictated. The AER also questioned the ability of Energex to reliably predict and measure the scale of the risk, as external insurance markets were unwilling to provide cover for these risks. As a consequence, the AER considered the most appropriate self insurance allowance for storm catastrophe was zero.[1345]

Public liability risks

The AER considered that Energex's proposed public liability self insurance allowance did not reflect the opex criteria. In the absence of an external insurance quote, the AER considered that the external insurance policy should be used as a maximum efficient benchmark in order to determine an estimate of the efficient allowance. The AER, used the information available to calculate an allowance of $7 528 per annum.[1346]

Retailer credit risk

The AER did not accept Energex's proposed self insurance allowance for retailer credit risk. In particular, the AER considered that, if material, this risk was better managed through the pass through mechanism. The AER also questioned the ability of Energex to accurately predict and measure the scale of the risk, as external insurance markets were unwilling to provide cover for these risks. Accordingly, the AER considered that the most appropriate self insurance allowance for retailer credit risk was zero.[1347]

H.1.2 Ergon Energy

The draft decision for Ergon Energy's proposed self insurance allowance is shown in table H.2.

[1345] AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, pp. 700–705.
[1346] AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, pp. 705–709.
[1347] AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, pp. 709–711.

Table H.2: AER draft conclusion on Ergon Energy's self insurance opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy regulatory proposal						
Storm catastrophe	1.1	1.1	1.1	1.1	1.1	5.3
Public liability	3.1	3.1	3.3	3.4	3.5	16.3
Total self insurance	4.2	4.2	4.3	4.4	4.5	21.5
AER draft decision						
Storm catastrophe	0	0	0	0	0	0
Public liability	.003	.003	.003	.003	.003	.016
AER approved self insurance allowance	.003	.003	.003	.003	.003	.016

Source: AER, *Draft decision, Queensland draft distribution determination*, November 2009, p. 712.
Note: Totals may not add due to rounding.

The AER assessed Ergon Energy's self insurance proposal against the following five principles:[1348]

- 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
- whether a self insurance premium can be determined and whether the self insurance event relates to an incurred cost
- whether the premium estimated is an efficient cost.

Storm catastrophe

The AER did not accept Ergon Energy's proposed self insurance allowance. In particular, the AER considered that Ergon Energy's proposed self insurance allowance for storm damage would be better managed, if material, via the cost pass through mechanism. In addition, the AER considered that non-material storm damage could be met through a prudent reprioritisation of the opex and capex allowances as expediency dictated. The AER also questioned the ability to reliably predict and measure the size and scale of the risk, as external insurance markets were unwilling to

[1348] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 694–699.

provide cover for these risks. As a consequence, the AER decided to reduce Ergon Energy's self insurance allowance for storm damage to zero.[1349]

Public liability risks

The AER considered that Ergon Energy's proposed public liability self insurance allowance did not reflect the opex criteria. In the absence of an external insurance quote, the AER considered that the external insurance policy should be used as a maximum efficient benchmark in order to determine an estimate of the efficient allowance. The AER used the information available to calculate an allowance of $3 218 per annum.[1350]

H.2 Revised regulatory proposals

H.2.1 Energex

Storm catastrophe

Energex acknowledged the AER's argument that events affecting key income generating assets are better dealt with through the cost pass through mechanism.[1351] Accordingly, Energex proposed to include significant storm events as a specific nominated pass through event, with a demarcation threshold of $2 million damage per event.

Public liability risks

Energex resubmitted its original self insurance proposal in relation to public liability risks as shown in table H.3.

Table H.3: Energex's forecast of public liability self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Public liability risks	1.2	1.2	1.3	1.3	1.3	6.3

Source: Energex, *Revised regulatory proposal*, January 2010, p. 31.

Energex's actuarial consultant, Finity Consulting Pty Ltd (Finity) considered that the AER's calculation of its public liability self insurance allowance was 'fundamentally flawed'.[1352] Finity stated that the AER failed to recognise that the distribution of public liability claims is highly skewed, with a small number of large losses and a high number of relatively small losses.[1353] Consequently, Energex argued that the cost of insurance for each dollar at the lower end is much higher than the cost of insurance per dollar at the higher end of the insurance policy.[1354]

1349 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 700–705 and pp. 709–711.
1350 AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 706–709.
1351 Energex, *Revised regulatory proposal*, January 2010, p. 23.
1352 Energex, *Revised regulatory proposal*, January 2010, p. 24.
1353 Energex, *Revised regulatory proposal*, January 2010, p. 24.
1354 Energex, *Revised regulatory proposal,* January 2010, p. 24.

As recommended by the AER in its draft decision, Energex requested an insurance quote from its broker for a zero deductible public liability policy. Energex's insurance broker advised that these products were unavailable. However, Energex did receive a quote for a public liability insurance policy with a $[redacted] deductible for general public liability, and a $[redacted] deductible for bushfire liability.[1355] This illustrated that to reduce the deductibles to the stated levels it would cost Energex approximately $0.95 million per annum on top of the insurance premiums Energex already pays. Energex stated that Finity's calculation of Energex's self insurance allowance was thus within a plausible range of the external quote.[1356]

Energex rejected the AER's method of calculating the public liability insurance allowance, and stated that it held the view that the appropriate method is to use actual claims history in the manner used by Finity.[1357]

Energex resubmitted its initial public liability costs of $6.3 million for the next regulatory control period.[1358]

Retailer credit risk

Energex proposed to include retailer credit risk as a specific nominated pass through event. Energex noted the AER's consideration that, should the event occur, a retailer credit risk event may constitute a general nominated pass through event.[1359]

Energex noted the recent corporate failure of electricity retailer Jackgreen (International) Pty Ltd. Energex argued that while the default payment amount is significant, it will be unlikely to meet the 1 per cent annual revenue threshold under a general nominated pass through event. In the absence of self insurance, Energex believes that it is unable to mitigate this risk.[1360]

In view of the AER's rejection of Energex's proposed self insurance allowance for retailer credit risk and the 1 per cent threshold required under a general nominated pass through event, Energex requested that the AER approve Energex's application to seek a specific nominated pass through event for retailer credit risk.[1361]

H.2.2 Ergon Energy

Storm catastrophe

Ergon Energy resubmitted its original self insurance proposal for storm catastrophe risks as shown in table H.4.

[1355] Energex, *Revised regulatory proposal*, January 2010, p. 24 and Energex, *Revised regulatory proposal*, January 2010, Appendix 4.1, *Willis Australia, Non–binding public liability premium estimate*, December 2009.
[1356] Energex, *Revised regulatory proposal*, January 2010, p. 25.
[1357] AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, p. 24.
[1358] Energex, *Revised regulatory proposal*, January 2010, p. 25.
[1359] AER *Draft decision*, *Queensland draft distribution determination*, November 2009, p. 343.
[1360] Energex, *Revised regulatory proposal,* January 2010, p. 23.
[1361] Energex, *Revised regulatory proposal,* January 2010, p. 23.

Table H.4: Ergon Energy's forecast storm catastrophe self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Storm catastrophe	1.1	1.1	1.1	1.1	1.1	5.3

Source: Ergon Energy, email response to the AER, PL872c, November 2009.
Note: Totals may not add due to rounding.

Ergon Energy reengaged Finity to provide comment on the draft decision on self insurance. Finity disagreed with several aspects of the AER's decision.

Regarding storm damage, Finity stated that, in insurance terms, the risk of storm damage is predictable and measurable. This was based on the fact that Finity used six years of storm damage data available. Further, Finity stated that there are many other insurance policies that have far fewer events and which are thus statistically more unreliable. Finity also mentioned that, an electricity transmission company had recently obtained insurance for tower structures and lines. In Finity's view there is greater uncertainty in predicting the losses associated with towers and lines than there is for Ergon Energy's poles and lines as significantly fewer events affect towers and lines.[1362]

In addition, Finity considered the draft decision was inconsistent with past AER decisions. In particular, Finity made reference to the self insurance allowances that were permitted in the Powerlink 2007–08 to 2011–12 transmission determination.[1363]

Finity argued that, while they agree that DNSPs have the ability to fund non-material losses through their opex and capex programs, Finity had been careful to ensure that Ergon Energy's claims for self insurance excluded any amounts from their capex and opex programs. Finity contended that this results in losses not included in the maintenance budgets and the pass through threshold being unclaimed.[1364]

Ergon Energy did not accept the proposition that a DNSP should fund a loss out of its opex allowance. Ergon Energy stated that it is reasonable to expect that a prudent and efficient DNSP, faced with a loss for which it cannot get external insurance or pass through, would fund these losses through either revenue allocated to opex or capex and/or self insurance. Ergon Energy went on to state that regardless of the mechanism used, a DNSP must make a judgement about the revenue necessary to cover the loss, having regard to the size of the loss and the probability that it will occur. Faced with this, there is no logical reason why a DNSP would always choose to fund the loss from opex allowances rather than self insurance (and vice–versa).[1365]

[1362] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP968c, Finity Consulting, Response to Australian Energy Regulator's draft determination on self insurance, p. ii.
[1363] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP968c, Finity, Response to AER, p. ii.
[1364] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP968c, Finity, Response to AER, p. 4.
[1365] Ergon Energy, *Revised regulatory proposal,* January 2010, Attachment Rp915c, Finity, Self insurance, p. 4.

Ergon Energy stated that if a DNSP does reprioritise its opex program as expediency dictates, this may result in other opex programs being underfunded. Given that the NER requires Ergon Energy's opex to be the sum that is required to meet the efficient costs of complying with Ergon Energy's regulatory obligations, requiring Ergon Energy to use the opex allowance to fund additional works which have not been accounted for is inconsistent with the revenue and pricing principle in section 7A(2) of the NEL.[1366]

Finity also refuted the AER's statements on the use of data from Cyclone Larry and wind speed assumptions. Finity argued that the AER has misunderstood the use of data from Cyclone Larry and that this data was used to calibrate a distribution of losses only, and that it was subsequently excluded from the calculation of the self insurance allowance. In addition, Finity stated that its assumption of a maximum wind speed of 200km/h was towards the lower end of the observed wind speed range based on comments from the Bureau of Meteorology.[1367]

Public liability risks

Ergon Energy resubmitted its original self insurance proposal for public liability risks as shown in table H.5.

Table H.5: Ergon Energy's forecast public liability self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Attritional	2.2	2.2	2.4	2.4	2.5	11.7
Large	0.8	0.8	0.9	0.9	0.9	4.0
Bushfire	0.1	0.1	0.1	0.1	0.1	0.6
Total public liability risks self insurance	3.1	3.1	3.2	3.3	3.4	16.3

Source: Ergon Energy, email response to the AER, PL872c, November 2009.
Note: Totals may not add due to rounding.

Regarding the AER's determination of a public liability self insurance allowance, Finity stated that the AER's methods were 'fundamentally flawed and totally inappropriate' as the AER failed to recognise that the distribution of public liability claims is highly skewed, with a small number of large losses and a high number of relatively small losses.[1368]

Finity also refuted the AER's claim that the use of an incurred but not reported (IBNR) benchmark was not appropriate. Finity argued that it was standard actuarial

[1366] Ergon Energy, *Revised regulatory proposal,* January 2010, Attachment RP915c, Finity, Self insurance, p. 4.
[1367] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP968c, Finity, Response to AER, pp. 5–6.
[1368] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP968c, Finity, Response to AER, p. 9.

practice to include an appropriate allowance for IBNR claims. Finity stated that an allowance for IBNR claims is required under the following:

- Accounting Standard AASB 137
- APRA General Insurance Standards
- Institute of Actuaries professional standard 300.

Finity went on to state that even if IBNR claims were excluded, the total self insurance allowance for public liability would fall from $16.6 million to $15.5 million.[1369]

In its response to the draft decision, Finity discussed the quote which Ergon Energy obtained from its insurance broker. This quote reduced the deductibles on its insurance policy from $[redacted] to $[redacted] for bushfires and from $[redacted] to $[redacted] for other claims.[1370] Ergon Energy was advised by its insurance brokers that insurance markets will not insure the entire deductible.[1371] The quote indicated that if Ergon Energy were to lower the deductibles to $[redacted] for bushfires and $[redacted] for other claims, it would cost Ergon Energy an additional $0.75 million per annum on top of the insurance premiums that Ergon Energy already pays.[1372]

H.3 Submissions

Energex

Energex discussed several aspects of its self insurance proposal, including the mitigation of significant storm damage risks, retailer credit risks and reporting arrangements.[1373] Energex raised concerns that it would have material unmitigated risk exposure in relation to significant atypical storm events and retailer credit risk losses because of the level at which the materiality threshold for general cost pass through events will apply.[1374]

Energex was concerned about the AER's apparent new position that if a commercial insurer is unwilling to take on a specific risk associated with damage to a distribution network, it is not prudent for network service providers to self insure for that risk.[1375]

[1369] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP968c, Finity, *R*esponse to AER, pp. 7–8.

[1370] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP984c, AON, Ergon Energy Liability Insurance – Reduction of self insured retention.

[1371] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP968c, Finity, Response to AER, p. 9.

[1372] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP984c, AON, Ergon Energy Liability Insurance – Reduction of self insured retention. This quote is comprised of an amount to reduce the bushfire liability deductible and an additional amount to reduce the general liability deductible.

[1373] Energex, *Submission on the draft determination*, February 2010.

[1374] Energex, *Submission on the draft determination*, February 2010, p. 21.

[1375] Energex, *Submission on the draft determination*, February 2010, pp. 21–22.

Energex stated that it believed there may be merit in a set of guidelines on self insurance being developed in consultation with stakeholders, to provide clarity around the role of self insurance and the assessment process to be applied by the AER. Energex stated that this would also facilitate a nationally consistent approach being applied by the AER across all DNSPs and TNSPs.[1376]

In relation to retailer credit risk, Energex stated that it expects to only recover modest amounts of the funds owed to it by Jackgreen (International) Pty Ltd, following the collapse of that retailer in December 2009.[1377] Energex stated that, as the draft decision stands, Energex would be forced to incur the cost of the event, as it is not permitted to self insure, nor would the losses meet the one per cent materiality threshold. While the AER stated that there are other options available to Energex to mitigate this risk, Energex considered that these options do not represent a comparable approach to risk mitigation as self insurance or a specific nominated pass through event.[1378]

Energex further stated that the reporting arrangements stipulated in the draft decision are too onerous, and would be a significant burden to administer.[1379]

Other submissions

The AER received a number of submissions on self insurance in response to its draft decision for ETSA Utilities.[1380] The AER has also had regard to these submissions in the context of the Qld DNSPs distribution determinations.

H.4 Issues and AER considerations

H.4.1 AER general issues and considerations

In the draft decision, the AER applied a principled approach in its assessment of the Qld DNSPs' self insurance proposals. This approach used the following five key principles to determine whether a self insurance event was consistent with the opex criteria, including the opex objectives:[1381]

- 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
- 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.

[1376] Energex, *Submission on the draft determination*, February 2010, p. 22.
[1377] Energex, *Submission on the draft determination*, February 2010, p. 23.
[1378] Energex, *Submission on the draft determination*, February 2010, pp. 23–24.
[1379] Energex, *Submission on the draft determination*, February 2010, pp. 27–28.
[1380] AER, *Draft decision, SA draft distribution determination 2010–11 to 2014–15*, November 2009.
[1381] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 486.

The AER considers that this approach is consistent with the NER and that it is a reasonable method of assessing self insurance proposals. However, the AER also considers if the self insurance event relates to a 'business as usual cost' or 'ongoing business activity', the cost is to be excluded from self insurance, in accordance with the EBSS final decision.[1382]

While the AER has not explicitly assessed each event against the five principles in this final decision, it must be noted that the AER assessed each self insurance event against the first five principles in the draft decision, and these principles underlie the AER's decision. The AER has incorporated consideration of consistency with the EBSS into its analysis within this decision.

H.4.2 Energex

Storm catastrophe

The AER has assessed Energex's proposal to address storm catastrophe losses via the cost pass through mechanism in chapter 15 of this decision.

The AER undertook several considerations concerning Energex's self insurance proposal with regard to storm catastrophe and its relationship with the cost pass through mechanism and emergency response opex.

The AER notes Energex's concern that if self insurance and a specific nominated cost pass through event are rejected by the AER, then Energex would be left exposed to unmitigated risks between $2 million and the materiality threshold for each event.

The AER considers that Energex is unlikely to experience a storm catastrophe that materially affects Energex's ability to efficiently and prudently provide distribution services. Finity notes that storms in January 2004 and November 2008 provide important indications of the damage that catastrophic storms inflict on the network. The AER considers that the storms of January 2004 should be excluded from the emergency response opex forecasts regardless of whether they are catastrophic or not, as these storms would not provide an indication of the damage that a storm of a similar magnitude could inflict on the Energex network. This is due to the fact that the Electricity Distribution and Service Delivery (EDSD) review, in part manifested through the January 2004 storms, addressed Energex's network performance, and recommended increased capex to address performance issues. Energex has tried to implement the recommendations arising from the EDSD review, and has spent significant capex improving the Energex network.[1383] Therefore, it can reasonably be expected that a similar storm would have a very different impact on Energex's network now, compared to the impact of the January 2004 storm. The AER considers that the January 2004 storms should be excluded from the opex forecasts and self insurance calculations in principle, as it is not representative of the current and future performance of Energex's network.

[1382] AER, *Final decision, Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008, Attachment E – Efficiency benefit sharing scheme, p. 6.

[1383] Energex, *Regulatory proposal*, July 2009, pp. 54–55 and p. 208.

The AER also notes that the two storms that were excluded from Energex's opex forecasts should have been excluded from the forecasts anyway, on the basis that the incurred costs would have met the materiality threshold. Energex advised the AER that the nominal costs for the January 2004 and November 2008 storms were $[redacted] and $[redacted] respectively.[1384] Therefore, Energex does not have a history of incurring costs associated with a 'storm catastrophe' as defined by Finity.

The AER accepts that a storm catastrophe event may impact Energex's network at some stage, the AER considers that there is insufficient historical data to reliably measure the probability and quantum of the risk.

The AER accepts that the efficient for storm catastrophe may be greater than zero, and that it may be possible to derive an actuarial estimate of a premium without a loss history. However, the AER does not believe that it is possible to determine an efficient premium which would satisfy the NER when a DNSP does not have a loss history associated with the risk. This is in accordance with the draft decision, which outlined the five key principles by which it considered that a self insurance proposal should be assessed.[1385] The AER considers that Energex's regulatory proposal in relation to storm catastrophe risks did not satisfy the principle that a self insurance risk must be predictable and measurable, as there is insufficient historical data to reliably measure the risk. This is in accordance with the NER, in particular section 6.5.6(c)(3), which states that all opex must be a reasonable expectation of the cost inputs required to achieve the opex objectives.

However, as the AER accepts that there is a risk that Energex's network could be materially affected by storms, the AER considers that Energex could apply for a general cost pass through in the event that costs incurred from a storm are material.

Finity made the following comment:[1386]

> The most severe storm (in terms of wind speed) for which we have full data from Energex is December 2007. This storm had a measured wind speed of 120km/h. However, this storm did not appear to be exceptionally damaging.

The AER considers this may reflect the increased capex on the Energex network and its consequent improved performance in severe storms. The AER notes Finity's assumption that, because the 2004 storms caused more damage than the December 2007 storms, they must therefore have recorded a higher wind speed.[1387] The AER considers this assumption is unreasonable, as it does not take into account the greatly increased capex that was approved for Energex in the current regulatory control period, and the associated improvement in network reliability and stability.

In addition, Finity does not take into account the vegetation management strategies that Energex has incorporated into its business as usual activities during the current regulatory control period. Energex also applied for, and the AER has approved, a large vegetation management allowance for the next regulatory control period. The

[1384] Energex, email response, AER.EGX.RP.09, 12 March 2010, confidential.
[1385] AER, *Draft decision*, *Queensland draft distribution determination,* November 2009, pp. 694–699.
[1386] Finity, *Review of self insurance program – Energex*, June 2009, p. 12, confidential.
[1387] Finity, *Review of self insurance program – Energex*, June 2009, p. 12, confidential.

AER considers the scale of vegetation management that has been undertaken in the current regulatory control period and is forecast to continue in the next regulatory control period is significant, and will mitigate damage to the network in a severe storm. Energex and Finity have not demonstrated how either the increased capex or the vegetation management opex have been taken into account in their estimation of storm catastrophe risks.

The AER also refers to the draft decision regarding recouping costs associated with replacing assets destroyed by storms.[1388] Assuming that Energex does 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 also reiterates its comments surrounding the issue of addressing a storm event through its emergency response or forced maintenance opex funds before seeking to have customers pay for additional costs.[1389] 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. As a DNSP will never know until after the event has occurred whether it classifies as a cost pass through event, the AER expects that for all catastrophic storm events a DNSP would act prudently to minimise the costs that would be passed through to customers. This may entail using some of the opex approved by the AER to address the repair costs. Even if the event were not to reach the materiality threshold for a cost pass through, the AER considers that a DNSP should address storm catastrophe costs, as defined by Finity, through a prudent reprioritisation of its opex pool of funds before seeking to pass through costs above budget forecasts through to customers.

If the DNSP had already overspent the emergency response funds, then the overspend associated with a catastrophic storm would be of the same nature as an overspend due to more attritional storm events than forecast. Energex has previously overspent its emergency response budget in a financial year without the provision of efficient distribution services being compromised.[1390]

Summary

In conclusion, the AER considers that storm catastrophe is not suitable for self insurance for the following reasons:

[1388] AER, *Draft decision*, *Queensland draft distribution determination,* November 2009, p. 703.
[1389] AER, *Draft decision*, *Queensland draft distribution determination,* November 2009, p. 702.
[1390] For example a significant overspend occurred in 2008–09. Energex, *Distribution and transmission operating programs*, 2006–16, July 2009, pp. 193–194; and Energex, *Revised regulatory proposal*, January 2010, RIN proforma 2.2.2, confidential.

- the AER does not consider that Energex would be materially affected by a storm that compromised its ability to provide distribution services where the costs were below the cost pass through materiality threshold

- Energex and Finity have not taken account of the mitigating effects of increased capex and vegetation management opex on the network

- the AER considers there is insufficient data to measure the risk and derive an efficient estimate of the cost to self insure for storm catastrophe

- any capex associated with asset replacement will be recouped, in addition to capex associated with assets that have been removed from the network

- a storm catastrophe event is similar in nature to an overspend within emergency response, and should thus be funded from the opex pool of funds.

The AER confirms its draft decision that storm catastrophe costs are not suitable for self insurance for the reasons discussed. However, the AER considers that Energex may be able to recoup storm catastrophe losses via a general cost pass through. The AER has assessed Energex's proposal to include storm catastrophe damage as a specified nominated pass through event in chapter 15 of this final decision.

Public liability risks

As part of the draft decision, the AER stated that:[1391]

> …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 basis for this statement was that, in the absence of an external quote illustrating the cost to insure the deductible of the insurance policy, the AER considered that the best way to judge the efficiency of the proposed allowance was a comparison with the external insurance policy held by the DNSP. However the AER recognised that:[1392]

> …the deductible will have a higher premium associated with it due to the higher probability of events occurring in this lower cost band.

The AER recognised that the methodology that it used to determine the self insurance premiums for public liability risks in its draft decision was approximate due to the fact that regular, lower cost events will have a higher premium per dollar of insurance coverage associated with them than relatively infrequent, higher cost events.[1393] The AER notes Energex's comments on the inaccuracy of this methodology and accepts that the methodology will produce a self insurance allowance that is not truly reflective of the cost to self insure the event. The AER considers that, if the DNSPs disagree with the AER's methodology and conclusions, the onus is on the DNSPs to provide further information in their revised proposals to justify its proposed costs.

[1391] AER, *Draft decision*, *Queensland draft distribution determination,* November 2009, p. 707.
[1392] AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, p. 707.
[1393] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 707–708.

The AER accepts Energex and Finity's arguments that the use of an IBNR benchmark is standard actuarial practice. The AER accepts that, as an allowance for IBNR is standard actuarial practice it is reasonable to include an IBNR benchmark within a self insurance allowance, even though it may not directly relate to the electricity distribution industry.

Energex provided a formal external quote from its insurance broker to decrease the deductibles from $[redacted] for general events and $[redacted] for bushfire events down to $[redacted] for general events and $[redacted] for bushfire events.[1394] The cost to reduce the deductibles to these levels would be around $[redacted] in addition to the premium for the primary layer of external insurance coverage.[1395]

The AER notes that Energex included public liability claims below the threshold of $[redacted] per claim within its opex forecasts. This means that the quote provided by Energex may overstate the true self insurance costs of lowering the deductible, as Energex is actually only exposed to costs between $[redacted] and $[redacted].

In confirming the draft decision, the AER still considers that an external quote should be used as an efficient benchmark under which the proposed self insurance amounts must fall. Energex proposed a self insurance allowance of $6.7 million for the next regulatory control period in relation to public liability. However, the external quote stated that it would theoretically cost Energex only $[redacted] to insure the deductibles down to $[redacted] for general liability and $[redacted] for fire liability. The AER considers that the external quote may overstate the true cost to self insure the deductibles due to profit margins. In addition, the AER has noted that the quote lowers the deductibles to $[redacted] for general, while Energex is only seeking to self insure down to $[redacted] for general. However, while the AER considers that the external quote is approximate, the AER maintains its position that an external quote should be utilised as a maximum efficient benchmark. Thus, the AER has rejected Energex's proposed public liability self insurance allowance, and substitutes a value of $[redacted] per annum as Energex's public liability allowance. This gives a total self insurance allowance of $4.75 million for public liability over the next regulatory control period.

Summary

The AER has used the external quote provided to the AER to reduce Energex's proposed self insurance allowance for public liability to $4.75 million over the next regulatory control period.

For the reasons discussed and as a result of the AER's consideration of Energex's regulatory proposal, revised regulatory proposal, submissions and other material, the AER is not satisfied that Energex's self insurance opex for public liability risks reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Energex's self insurance opex for public liability risks by $1.5 million ($2009–10) results in expenditure that reasonably reflects the opex criteria, including the opex objectives and is the minimum adjustment necessary for

[1394] Energex, *Revised regulatory proposal*, January 2010, Appendix 4.1, Willis Australia Non–binding public liability premium estimate – December 2009, confidential.

[1395] Energex, *Revised regulatory proposal*, January 2010, Appendix 4.1, Willis Australia Non–binding public liability premium estimate – December 2009, confidential.

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 H.4.1 and the opex factors.

Retailer credit risk

The AER assessed Energex's proposal to address retailer credit risk losses via the cost pass through mechanism in chapter 15 of this decision.

H.4.3 Ergon Energy

Storm catastrophe

The AER notes Ergon Energy's concerns that if Ergon Energy were to fund storm catastrophe costs through a reprioritisation of its opex program as required, then other opex programs may be underfunded.[1396] The AER considers that this should not be a material concern for a DNSP. This is consistent with past practice and reflects the fact that in the period immediately following a catastrophic event, resources are limited and emergency work needs to be undertaken by reprioritising existing programs. During the current regulatory control period, Ergon Energy was required to fund storm catastrophe costs, if they had occurred, through its opex program, as a self insurance allowance was not provided by the QCA in its final determination for these events.[1397]

The AER considers that this approach does not jeopardise the provision of distribution services as the quantum of the funds reallocated would be non–material, by definition.[1398] In addition, the AER considers that this risk is similar to the risk of an overspend due to a more severe storm season than was expected leading to greater than forecast attritional storm related costs. This may also mean that other opex programs may be underfunded or delayed. However, the risks related to forced maintenance due to attritional storms are symmetrical; that is, there is also the chance that there will be a less severe storm season than forecast, and thus there may be less attritional storm related costs incurred. The AER expects that when this would occur, delayed or underfunded projects would be addressed, and that the DNSP would put in place maintenance plans to manage the risk of overspends within the forced maintenance opex category in the future. The AER considers that this should be a business as usual process for all DNSPs.

The AER notes Finity's comments in regard to the rejection of a self insurance allowance for storm catastrophe on the basis that self insurance for this event was not predictable and measurable. Notably, Finity stated that it considers the risk to be predictable and measurable. Finity used six years of data relating to storm losses as well as approximately 500 emergency outages per year to inform its calculations. In

[1396] Ergon Energy *Revised regulatory proposal*, January 2010, Attachment RP915c, Self insurance, p. 4.
[1397] QCA, *Final determination – Regulation of electricity distribution*, April 2005, pp. 126–129.
[1398] Ergon Energy would have the ability to recoup any material costs associated with a severe storm via the cost pass through mechanism.

addition, Finity stated that it had access to information for both Ergon Energy and Energex to ensure consistency between the results.[1399]

The AER notes that within the six years of historical storm loss data, Ergon Energy did not provide Finity with any data associated with such storm catastrophe events, as defined by Finity, within the current regulatory control period.[1400] As discussed in relation to Energex, while the AER accepts that a storm catastrophe event may impact Ergon Energy's network at some stage, the AER considers that there is insufficient historical data to reliably measure the probability and quantum of the risk.

As discussed in the assessment of Energex's storm catastrophe risks, the AER does not consider that it is possible to measure, quantify and determine an efficient premium without utilising a loss history that directly relates to the losses being self insured. This is in accordance with the draft decision, which outlined the five key principles by which it considered that a self insurance proposal should be assessed.

The AER accepts that there is a risk that Ergon Energy's network could be materially affected by severe storms, the AER considers that Ergon Energy could apply for a general cost pass through in the event that costs incurred from a storm are material.

The AER also reiterates its comments surrounding the issue of addressing a storm event through its emergency response or forced maintenance opex before seeking to have customers pay for additional costs. 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. As a DNSP will never know until after the event has occurred whether it classifies as a cost pass through event, the AER expects that for all catastrophic storm events a DNSP would act prudently to minimise the costs that would be passed through to customers. This may entail using some of the opex approved by the AER to address the repair costs. Thus, even if the event were not to reach the materiality threshold for a cost pass through, the AER considers that a DNSP should address storm catastrophe costs, as defined by Finity, through a prudent reprioritisation of its opex pool of funds before seeking to pass through costs above budget forecasts to customers.

If the DNSP had already overspent the emergency response funds, then the overspend associated with a catastrophic storm would be of the same nature as an overspend due to more attritional storm events than forecast. Ergon Energy has previously overspent its forced maintenance budget in a financial year without the provision of efficient distribution services being compromised.[1401]

The AER also considers that Ergon Energy's wide geographic spread of assets is the primary reason Ergon Energy has historically experienced attritional storm costs only.

[1399] Ergon Energy, Revised regulatory proposal, January 2010, Attachment RP968c, Finity, Response to Australian Energy Regulator's draft determination on self insurance, p. 4.

[1400] Ergon Energy has not experienced a storm event which falls into this category. Finity was forced to use Cyclone Larry as a proxy to determine the amount of damage to the network that may be incurred from a storm catastrophe. Finity, *Review of Self Insurance Program*, March 2009, pp. 5, 13 and 25; and Ergon Energy, email response, AER.EE.RRP.28.3, 12 March 2010.

[1401] For example there was a significant overspend in 2005–06. Ergon Energy, *Revised regulatory proposal*, RIN proforma 2.2.2.

This geographic spread acts as a natural mitigation of the risk of incurring costs related to storm catastrophes. Ergon Energy's assets are spread throughout Queensland, rather than being concentrated in a relatively small area such as a DNSP that services a capital city.[1402] This may mean that Ergon Energy's storm attritional costs are comparatively high, given the broad spread of assets across Queensland and the increased chance of incurring regular storm costs. However, as storms tend to have an impact in a relatively small area, it also means that Ergon Energy is less likely to incur storm catastrophe costs due to the wide geographic spread of assets. The AER considers that for a storm to fall into the storm catastrophe category, it would need to be of unusual strength or affect a large portion of Ergon Energy's network. The AER notes that the only storm that has affected Ergon Energy's network in such a manner was Cyclone Larry. However, the AER notes that Ergon Energy applied for a cost pass through for the costs incurred during Cyclone Larry, and the pass through was approved by the QCA.[1403]

The AER also considers that it is reasonable to assume that if Ergon Energy's network were to experience a similar storm, it would likely incur less losses per event than Energex due to the wider geographic spread of its assets. These costs would consequently be incorporated within Ergon Energy's forced maintenance budgets.

The AER also notes that this is consistent with the treatment of storm damage costs in the current regulatory control period. This is because there have been no exclusions of costs associated with storm catastrophe, as Ergon Energy did not experience any such events during the current regulatory control period.

The AER also notes Ergon Energy's concerns that requiring it to use opex to fund additional storm repair works which had not been accounted for would be inconsistent with the revenue and pricing principles in section 7A(2) of the NEL.[1404] The AER notes that the revenue and pricing principles do not place any obligations upon the AER. Section 7A(2) of the NEL merely outlines factors that the AER must consider under certain circumstances.

The AER is concerned about the method of defining a storm catastrophe event. Finity proposed using wind speed as a defining factor to define catastrophic storms. The AER is not convinced that maximum wind gust speed is a reliable measure of determining the amount of damage that a storm may do to a DNSP's network. In its self insurance report for Energex, Finity made the following comment:[1405]

> The most severe storm (in terms of wind speed) for which we have full data from Energex is December 2007. This storm had a measured wind speed of 120km/h. However, this storm did not appear to be exceptionally damaging.

[1402] For example, Ergon Energy's opening regulatory asset base, as determined in the draft decision, is \$7105 million with a total line length of 146 339 km. Energex, by comparison, has a far more concentrated asset base, with an opening regulatory asset base of \$7887 million and a total line length of 51 349 km. See AER, *Draft decision*, *Queensland draft distribution determination,* November 2009, p. 51; and AER, *State of the Energy Market*, 2009, pp. 156–157.

[1403] QCA, *Final decision – cost pass through application Ergon Energy – Tropical Cyclone Larry*, September 2008.

[1404] Ergon Energy, *Revised regulatory proposal*, Attachment RP915c, Self insurance, January 2010, p. 4.

[1405] Finity, *Review of self insurance program –Energex*, June 2009, p. 12, confidential.

Energex, with a greater asset concentration than Ergon Energy, did not experience any significant damage when wind speeds reached 120km/h. The AER is not convinced that a threshold of 120km/h should be applied when defining a catastrophic storm. The AER considers that the factors associated with mitigating damage from wind speed, such as urbanisation and asset dispersion, have not been taken into account by Finity's analysis.

The AER also refers to the draft decision regarding recouping costs associated with replacing assets destroyed by storms. Assuming that Ergon Energy does 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.

Summary

The AER considers that the appropriate self insurance allowance for storm catastrophe for Ergon Energy is $0 for the following reasons:

- a DNSP may fund costs associated with a storm catastrophe loss through a prudent reprioritisation of the opex pool of funds
- the AER considers that a storm catastrophe is of a similar nature to an overspend within the forced maintenance opex category and should thus be treated in a similar fashion
- the AER considers that there is insufficient data to measure the risk
- Ergon Energy's wide geographic spread of assets acts as a natural mitigation to storm catastrophe
- any capex associated with asset replacement will be recouped, in addition to capex associated with assets that have been removed from the network.

For the reasons discussed and as a result of the AER's consideration of Ergon Energy's regulatory proposal, revised regulatory proposal, submissions and other material, the AER is not satisfied that Ergon Energy's self insurance opex for storm catastrophe risks reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's self insurance opex for storm catastrophe risks by $5.3 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 self insurance principles outlined in section H.4.1 and the opex factors.

The AER considers that Ergon Energy may be able to recoup storm catastrophe losses via a general cost pass through. The AER assessed Ergon Energy's proposal to include storm catastrophe damage as a specified nominated pass through event in chapter 15 of this final decision.

Public liability risks

In considering the interaction with the EBSS, outlined in section H.4.1 above, the AER considers that the attritional public liability claims included within Ergon Energy's self insurance proposal do not satisfy the principle in that they would be considered 'business as usual costs' or 'ongoing business activities'. In accordance the AER's EBSS final decision[1406] the AER considers that the total amount proposed by Ergon Energy in relation to attritional public liability claims should be rejected from self insurance and transferred to controllable opex. This is consistent with the approach applied by Energex, and consistent with the approach the AER applied to ETSA Utilities.

Similar to its considerations for Energex, the AER recognised that the methodology that it used to determine the self insurance allowance for public liability risks in its draft decision was approximate due to the fact that regular, lower cost events will have a higher premium per dollar of insurance coverage associated with them than relatively infrequent, higher cost events.[1407] The AER notes Ergon Energy's comments on the inaccuracy of this methodology and accepts that the methodology will produce a self insurance allowance that is not truly reflective of the cost to self insure the event. The AER considers that, if the DNSPs disagree with the AER's methodology and conclusions, the onus is on the DNSPs to provide further information in their revised proposals to justify its proposed costs.

The AER also accepts Energex and Finity's arguments that the use of an IBNR benchmark is standard actuarial practice. The AER accepts that, as an allowance for IBNR is standard actuarial practice it is reasonable to include an IBNR benchmark within a self insurance allowance, even though it may not directly relate to the electricity distribution industry.

Ergon Energy provided a quote from its insurance broker to decrease the deductibles from $[redacted] for general events and $[redacted] for bushfire down to $[redacted] for general events and $[redacted] for bushfire.[1408] The impact on pricing by reducing the deductible levels was around $[redacted] in addition to the premium for the primary layer of insurance.[1409]

In maintaining its position that was outlined in the draft decision, the AER still considers that an external quote should be used as an efficient benchmark under which the proposed self insurance amounts must fall. Ergon Energy proposed a self insurance allowance of $4.7 million in relation to large and fire liability claims for the next regulatory control period. However, the external quote stated that it would theoretically cost Ergon Energy only $750 000 per annum to insure the deductibles down to $[redacted] for general liability and $[redacted] for fire liability. The AER considers

[1406] AER, *Final decision, Electricity DNSPs EBSS*, June 2008, Attachment E – Efficiency benefit sharing scheme, p. 6.
[1407] AER, *Draft decision, Queensland draft distribution determination*, November 2009, pp. 707–708.
[1408] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP984c.
[1409] Ergon Energy, *Revised regulatory proposal*, January 2010, Attachment RP984c.

that the external quote may overstate the true cost to self insure the deductibles due to profit margins. In addition, the AER has noted that the quote lowers the deductibles to $[redacted] for general liability, while Ergon Energy's large liability claims only go down to $[redacted] for general liability. However, while the AER considers that the external quote is approximate, the AER maintains its position that an external quote should be utilised as a maximum efficient benchmark. Thus, the AER has rejected Ergon Energy's proposed public liability self insurance allowance, and substitutes a value of $750 000 per annum as Ergon Energy's public liability allowance. This gives an allowance of $3.75 million over the next regulatory control period in relation to public liability claims.

Summary

The AER considers that the appropriate self insurance allowance for public liability risks for Ergon Energy is $3.75 million for the following reasons:

- attritional public liability costs are 'business as usual' costs and, for consistency with the AER's EBSS final decision, should be incorporated into Ergon Energy's opex forecasts. This results in a reallocation of self insurance of $11.9 million to controllable opex

- the AER has used the external quote provided by Ergon Energy as a maximum efficient benchmark.

For the reasons discussed and as a result of the AER's consideration of Ergon Energy's regulatory proposal, revised regulatory proposal, submissions and other material, the AER is not satisfied that Ergon Energy's self insurance opex forpublic liability risks reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's self insurance opex for public liability risks by $18.4 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 self insurance principles outlined in section H.4.1 and the opex factors.

H.5 Reporting requirements

The AER confirms its draft decision that self insurance events should be reported as contingent liabilities, in accordance with AASB 137.

The AER notes Energex's concerns surrounding the reporting arrangements in relation to self insurance that were outlined in the AER's draft decision. In its submission on the AER's draft decision Energex stated that the reporting requirements would impose a significant burden on Energex to administer. This is because Energex annually processes hundreds and sometimes thousands of below deductible public liability claims each of which would need to be reported to the AER.[1410]

[1410] Energex, *Submission on the draft determination*, February 2010, p. 28.

The AER notes, however, that Energex is only seeking to self insure for events above $100 000 per event. Events that incur costs below this threshold are included within Energex's controllable opex forecasts. The AER would expect that only the events that are seeking to be self insured would be reported to the AER under the reporting arrangements proposed within the draft decision. The AER would not expect that recurrent, low cost events would be reported to the AER under the self insurance reporting guidelines. The recurrent, low cost public liability events would be reported as a category within the DNSP's annual opex regulatory reporting instruments.

The AER notes that Ergon Energy did not make any comments surrounding the self insurance reporting arrangements that were outlined in the AER's draft decision. However, the AER considers that the same regime would apply to Ergon Energy as would apply to Energex. That is, any recurrent, low cost events should be included within the DNSP's annual opex regulatory reporting instruments, while only large public liability claims would be required to be reported to the AER in line with the reporting arrangements outlined in the AER's draft decision. In Ergon Energy's case, this would mean only those claims that are classified as large public liability claims and fire liability claims would need to be reported to the AER in accordance with the AER's self insurance reporting requirements.

However, the AER has revised its approach to the reporting arrangements that would be imposed upon the Queensland DNSPs. The AER stated the following in the draft decision:[1411]

> 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 that are 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 has reviewed this approach and had regard to Energex's comments surrounding the burden of the proposed reporting requirements. The AER thus considers that reporting of self insurance events, as outlined in appendix L of this final decision, should only be reported annually as part of the annual reporting requirements of the DNSPs. However, the AER maintains that the form of reporting

[1411] AER, *Draft decision*, *Queensland draft distribution determination*, November 2009, p. 797.

should be as outlined within the draft decision, and reiterated within this final decision.

H.6 AER conclusion

Energex

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, revised regulatory proposal, submissions and other material the AER is not satisfied that the self insurance opex proposed by Energex reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Energex's proposed self insurance opex by $1.5 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 self insurance principles outlined in the draft decision and the opex factors.

The AER's conclusions on Energex's self insurance allowance are shown in table H.6.

Table H.6: Energex self insurance allowances 2010–15 ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Proposed public liability self insurance	1.2	1.2	1.3	1.3	1.3	6.3
AER adjustments	0.3	0.3	0.3	0.3	0.3	1.5
Total public liability self insurance	0.9	0.9	0.9	0.9	0.9	4.7

Note: Totals may not add due to rounding.

Ergon Energy

For the reasons discussed and as a result of the AER's analysis of the regulatory proposal, revised regulatory proposal, submissions and other information the AER is not satisfied that the self insurance opex proposed by Ergon Energy reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing Ergon Energy's proposed self insurance opex by $18.4 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 self insurance principles outlined in the draft decision and the opex factors.

The AER's conclusions on Ergon Energy's self insurance allowance are shown in table H.7.

While the AER does not consider the self insurance allowance appropriate, it considers that in the event of a material loss in relation to storm catastrophe risks, 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 H.7: AER's conclusion on Ergon Energy's self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Proposed storm catastrophe	1.1	1.1	1.1	1.1	1.1	5.3
Proposed public liability risks	3.1	3.1	3.3	3.4	3.5	16.3
AER adjustments[a]	3.5	3.5	3.7	3.8	3.9	18.4
Total self insurance	0.7	0.7	0.7	0.7	0.7	3.7

Note: Totals may not add due to rounding.

(a) AER adjustments include the reallocation of $11.9 million of attritional public liability claims to controllable opex.

I. Alternative control services – quoted services

Tables I.1 and I.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 I.2 and I.4 set out the AER's indicative 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 formula based price cap control mechanisms, as set out in chapter 18 of this decision, and each illustrative quoted service configuration. The indicative prices do not represent a binding capped price for an individual quoted service.

Energex

Table I.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	3 686.52	3 900.10	4 091.61	4 261.62	4 319.62
Customer requested works to allow customer or contractor to work close	5 478.99	5 762.94	5 970.20	6 133.59	6 207.12
Non–standard data and metering services	99.04	105.13	111.08	116.59	118.28
Emergency recoverable works and rectification of illegal connections	8 222.84	8 700.29	9 135.87	9 528.34	9 674.77
Large customer connections	312 412.03	328 433.42	341 193.06	352 079.59	357 861.72
Design specification and other subdivision activities	1 188.43	1 261.51	1 333.01	1 399.08	1 419.37
Unmetered services, including street lighting	1 597.89	1 691.02	1 775.33	1 850.51	1 875.86

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
After hours provision of any fee–based service (excluding re–energisations)	1 442.13	1 525.34	1 603.46	1 676.03	1 709.70
Supply abolishment – complex	394.15	418.38	442.10	464.01	470.74
Additional crew	104.45	110.87	117.16	122.96	124.75
Temporary connection – complex	40 324.73	42 516.35	44 277.02	45 750.97	46 330.68
Loss of asset	6 180.80	6 148.15	6 116.20	6 084.93	6 054.34
Other recoverable work[a]	n/a	n/a	n/a	n/a	n/a

Source: Energex, response to information request AER.EGX.RRP.02, 26 February 2010 (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 I.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	3 801.93	3 985.26	4 204.75	4 374.32	4 442.47
Customer requested works to allow customer or contractor to work close	5 702.62	5 890.79	6 124.74	6 255.31	6 291.19
Non–standard data and metering services	101.59	107.40	114.27	120.10	122.62
Emergency recoverable works and rectification of illegal connections	8 454.12	8 877.01	9 375.88	9 775.93	9 956.39
Large customer connections	321 662.10	334 088.36	348 553.20	358 788.85	364 102.04
Design Specification and other subdivision activities	1 219.06	1 288.80	1 371.19	1 441.19	1 471.41

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Unmetered services, including street lighting	1 647.04	1 727.91	1 824.59	1 900.12	1 930.75
After hours provision of any fee–based service (excluding re–energisations)	1 471.48	1 549.88	1 639.06	1 716.16	1 759.75
Supply abolishment – complex	404.31	427.43	454.76	477.97	488.00
Additional crew	107.14	113.27	120.51	126.66	129.32
Temporary connection – complex	41 812.20	43 453.42	45 455.79	46 786.02	47 248.97
Loss of asset	8 514.70	8 712.11	8 939.74	9 053.27	9 124.64
Other recoverable work[a]	n/a	n/a	n/a	n/a	n/a

Source: Energex, response to information request, 29 April 2010 (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.

Ergon Energy

Table I.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	173 315.71	178 653.02	180 988.51	186 637.13	221 513.60
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
Removal or relocation of Ergon Energy assets at customer request	32 233.23	33 277.16	33 717.31	34 762.60	34 983.86

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Relocate point of attachment	794.90	816.17	840.58	882.86	907.86
Tiger tails	464.73	476.71	490.48	514.35	528.48
Meter data service provider services	124.19	128.02	132.39	139.95	144.39
Meter data service provider services above minimum requirements	428.77	440.81	454.59	478.45	492.53
Meter test	454.48	467.31	482.00	507.42	522.42
Change tariff	280.30	287.76	296.32	311.15	319.92
Change time switch	140.15	143.88	148.16	155.57	159.96
Removal of meter	227.24	233.65	241.00	253.71	261.21
Removal of load control device	227.24	233.65	241.00	253.71	261.21
Special read	69.74	71.58	73.69	77.34	79.50
Reprogram card meters	420.46	431.64	444.48	466.72	479.88
Exchange meter	340.86	350.48	361.50	380.57	391.82
Move meter	340.86	350.48	361.50	380.57	391.82
Connection service above minimum requirements	928.95	955.46	975.82	1 014.89	1 032.73
Overhead service upgrade	662.41	680.14	700.48	735.72	756.55
Underground service upgrade	4 271.74	4 409.28	4 481.08	4 637.42	4 684.77

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Meter service above minimum requirements	763.13	787.03	801.81	832.11	843.39
Prepayment meters at customer request	1 087.10	1 120.05	1 145.70	1 194.61	1 217.14
Temporary disconnection and reconnection	340.86	350.48	361.50	380.57	391.82
De–energisation after hours	236.46	243.26	251.04	264.50	272.44
Re–energisation after hours	188.02	193.43	199.62	210.32	216.64
Attend loss of supply (not DNSP fault)	483.92	497.22	512.47	538.87	554.47
Emergency recoverable works	1 375.58	1 411.91	1 453.62	1 525.89	1 568.64
Subdivision fees	1 261.67	1 300.61	1 345.01	1 421.76	1 466.91
Project fees	485.26	500.23	517.31	546.83	564.19
High load escorts	6 515.36	6 710.11	6 932.52	7 317.10	7 543.57
Rectify illegal connections	585.92	602.51	621.50	654.36	673.75
Conversion of aerial bundled cables	907.82	932.40	955.59	997.69	1 019.98
Provision of service or additional crew	350.38	359.70	370.40	388.94	399.90

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP918c (confidential).

Table I.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	127 406.51	132 154.26	136 864.68	141 816.70	146 971.65
Design and construct of new large customer connection assets – worked example 2	7 890 663.97	8 186 356.43	8 485 689.32	8 799 957.26	9 126 636.72
Design and construct of new large customer connection assets – worked example 3	8 638 151.66	8 961 665.67	9 287 509.90	9 629 220.27	9 984 274.24
Removal or relocation of Ergon Energy assets at customer request	24 965.41	25894.80	26818.51	27790.85	28803.54
Relocate point of attachment	564.75	584.62	606.39	630.85	656.94
Tiger tails	293.48	303.80	315.12	327.83	341.39
Meter data service provider services	128.95	133.49	138.46	144.04	150.00
Meter data service provider services above minimum requirements	349.81	362.11	375.60	390.75	406.91
Meter test	376.50	389.75	404.26	420.56	437.96
Change tariff	195.65	202.54	210.08	218.55	227.59
Change time switch	97.83	101.27	105.04	109.28	113.80
Removal of meter	188.25	194.87	202.13	210.28	218.98
Removal of load control device	188.25	194.87	202.13	210.28	218.98
Special read	47.14	48.80	50.61	52.65	54.83
Reprogram card meters	293.48	303.80	315.12	327.83	341.39

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Exchange meter	282.38	292.31	303.19	315.42	328.47
Move meter	282.38	292.31	303.19	315.42	328.47
Connection service above minimum requirements	626.50	649.22	672.86	698.54	725.61
Overhead service upgrade	470.63	487.18	505.32	525.70	547.45
Underground service upgrade	3 482.22	3 610.52	3 740.37	3 878.84	4 023.77
Meter service above minimum requirements	613.38	635.81	658.81	683.56	709.56
Prepayment meters at customer request	882.52	914.38	947.78	984.26	1 022.78
Temporary disconnection and reconnection	282.38	292.31	303.19	315.42	328.47
De–energisation after hours	202.15	209.26	217.05	225.80	235.14
Re–energisation after hours	160.74	166.40	172.59	179.55	186.98
Attend loss of supply (not DNSP fault)	365.32	378.17	392.25	408.08	424.96
Emergency recoverable works	938.73	971.75	1 007.94	1 048.59	1 091.97
Subdivision fees	1 310.04	1 356.12	1 406.61	1 463.35	1 523.88
Project fees	503.86	521.58	541.01	562.83	586.11
High load escorts	6 260.92	6 481.15	6 722.49	6 993.63	7 282.92
Rectify illegal connections	489.13	506.34	525.19	546.38	568.98

Quoted service, continued	2010–11	2011–12	2012–13	2013–14	2014–15
Conversion of aerial bundled cables	584.52	605.43	627.70	652.29	678.36
Provision of service or additional crew	244.57	253.17	262.60	273.19	284.49

J. Alternative control services – quoted services

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K. Alternative control services – fee based services

Tables K.1, K.2, K.3 and K.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 K.5, K.6, K.7 and K.8 set out the AER's indicative 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 formula based price cap control mechanisms, as set out in chapter 18 of this final decision and do not represent a binding capped price for each fee based service.

Table K.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	5.29%	4.37%	4.83%	1.60%

Source: Energex, *Revised regulatory proposal*, January 2010, p. 55.

Table K.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	–34.81%	88.52	93.20	97.27	101.97	103.60
Attending loss of supply – LV customer installation at fault – business hours	–39.28%	98.95	104.18	108.73	113.98	115.81
Overhead service replacement – single phase	23.83%	269.70	283.97	296.36	310.67	315.65
Overhead service replacement – multiple phase	17.01%	317.78	334.59	349.20	366.06	371.92
De–energisation	–18.55%	44.26	46.60	48.64	50.98	51.80
Meter test	–23.93%	103.30	108.76	113.51	118.99	120.90
Meter inspection	0.00%	79.22	83.41	87.05	91.26	92.72

Fee based service, continued	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Reconfigure meter	20.36%	65.57	69.04	72.05	75.53	76.74
Off–cycle meter read	–74.78%	7.32	7.71	8.04	8.43	8.57
Site visit	4.35%	56.61	59.60	62.21	65.21	66.25
Locating Energex underground cables	–10.29%	121.82	128.26	133.86	140.33	142.57
Temporary connection	20.30%	784.40	825.90	861.95	903.57	918.04
Re–energisation – business hours	–46.72%	38.58	40.62	42.39	44.44	45.15
Re–energisation – after hours	–7.95%	109.86	115.67	120.72	126.55	128.58
Re–energisation (visual) – business hours	–9.57%	65.48	68.94	71.95	75.43	76.64
Re–energisation (visual) – after hours	20.24%	143.51	151.10	157.70	165.31	167.96
Re–energisation non–payment (visual) – business hours	–9.57%	65.48	68.94	71.95	75.43	76.64
Re–energisation non–payment (visual) – after hours	20.24%	143.51	151.10	157.70	165.31	167.96
Supply abolishment	179.97%	304.72	320.84	334.85	351.02	356.63
Unmetered supply	–49.78%	136.44	143.66	149.93	157.17	159.69
Street light glare screening	0.26%	128.77	135.58	141.50	148.33	150.71
Replacement of standard luminaries with aero screen units (per street light)	–3.11%	294.34	309.91	323.44	339.06	344.49

Source: Energex, *Revised regulatory proposal*, January 2010, p. 55.

Table K.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[a]	As per price	3.77	3.81	3.84	3.87

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP919c (confidential).
(a) This is the average for the remaining fee based services and range from 3.45 per cent to 4.10 per cent increases in any given regulatory year.

Table K.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	733.64	766.65	801.15	837.20	874.88
project fees	n/a	733.64	766.65	801.15	837.20	874.88
De–energisation during business hours – urban/short rural feeders	n/a	116.33	120.77	125.39	130.19	135.17
De–energisation during business hours – long rural/isolated feeders	n/a	568.09	589.82	612.38	635.80	660.11
Re–energisation during business hours – urban/short rural feeders	n/a	92.50	96.04	99.71	103.52	107.48
Re–energisation during business hours – long rural/isolated feeders	n/a	529.46	549.71	570.74	592.56	615.23
Re–test at customer's installation during business hours – urban/short rural feeders	n/a	397.45	412.65	428.43	444.81	461.83
Re–test at customer's installation during business hours – long rural/isolated feeders	n/a	794.90	825.30	856.86	889.63	923.65
Supply abolishment during business hours – long rural/isolated feeders	n/a	397.45	412.65	428.43	444.81	461.83
Supply abolishment during business hours – urban/short rural feeders	n/a	794.90	825.30	856.86	889.63	923.65

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	n/a	662.41	687.75	714.05	741.36	769.71
Temporary builders supply, not in permanent position– single phase metered – business hours – long rural/isolated feeders	n/a	1059.86	1100.40	1142.48	1186.17	1231.54
Temporary builders supply not in permanent position – multi phase metered – business hours – urban/short rural feeders	n/a	662.41	687.75	714.05	741.36	769.71
Temporary builders supply not in permanent position – multi phase metered – business hours – long rural/isolated feeders	n/a	1059.86	1100.40	1142.48	1186.17	1231.54
Restoration of supply required due to customer action, during business hours – urban/short rural feeders	n/a	397.45	412.65	428.43	444.81	461.83
Restoration of supply required due to customer action, during business hours – long rural/isolated feeders	n/a	794.90	825.30	856.86	889.63	923.65
Wasted truck visit – one person crew – urban/short rural feeders	n/a	84.66	87.90	91.26	94.75	98.37
Wasted truck visit – one person crew – long rural / isolated feeders	n/a	338.64	351.59	365.04	379.00	393.49
Wasted truck visit – two person crew – urban/short rural feeders	n/a	131.77	136.81	142.04	147.47	153.11
Wasted truck visit – two person crew – long rural / isolated feeders	n/a	527.07	547.23	568.15	589.88	612.44

Source: Ergon Energy, *Revised regulatory proposal*, January 2010, attachment RP919c (confidential).
Notes: Ergon Energy did not provide a price path for the current regulatory years price and the price in the first year of the next regulatory control period.

Table K.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	As per price	4.80%	5.00%	4.44%	3.42%

Source: Energex, response to information request, 29 April 2010.

Table K.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	–33.83%	89.85	94.16	98.87	103.26	106.80
Attending loss of supply – low voltage customer installation at fault – business hours	–38.42%	100.36	105.18	110.43	115.34	119.29
Overhead service replacement – single phase	26.16%	274.76	287.95	302.34	315.77	326.58
Overhead service replacement – multiple phase	19.18%	323.67	339.20	356.16	371.98	384.72
De–energisation	–17.19%	45.00	47.16	49.52	51.72	53.49
Meter test	–23.43%	103.98	108.97	114.42	119.50	123.59
Meter inspection	0.00%	80.31	84.16	88.37	92.30	95.46
Reconfigure meter	22.21%	66.58	69.78	73.26	76.52	79.14
Off–cycle meter read	–74.16%	7.50	7.86	8.25	8.62	8.91
Site visit	6.30%	57.67	60.44	63.46	66.28	68.55
Locating Energex underground cables	–9.70%	122.62	128.50	134.93	140.92	145.75

Fee based service, continued	First year price path	2010–11	2011–12	2012–13	2013–14	2014–15
Temporary connection	22.53%	798.91	837.25	879.10	918.15	949.60
Re–energisation – business hours	–45.85%	39.21	41.09	43.15	45.06	46.61
Re–energisation – after hours	–6.25%	111.89	117.26	123.12	128.59	132.99
Re–energisation (visual) – business hours	–7.94%	66.66	69.86	73.35	76.61	79.23
Re–energisation (visual) – after hours	22.48%	146.18	153.20	160.85	168.00	173.75
Re–energisation non–payment (visual) – business hours	–7.94%	66.66	69.86	73.35	76.61	79.23
Re–energisation non–payment (visual) – after hours	22.48%	146.18	153.20	160.85	168.00	173.75
Supply abolishment	185.92%	311.19	326.12	342.42	357.64	369.88
Unmetered supply	–49.45%	137.34	143.93	151.12	157.84	163.24
Street light glare screening	3.34%	132.73	139.10	146.05	152.54	157.76
Replacement of standard luminaries with aero screen units (per street light)	1.01%	306.85	321.58	337.65	352.65	364.73

Source: Energex, response to information request, 29 April 2010.

Table K.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	3.52%	3.72%	4.03%	4.14%

Source: Ergon Energy, response to information request, 5 May 2010.

Table K.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	761.76	788.56	817.92	850.91	886.11
project fees	n/a	761.76	788.56	817.92	850.91	886.11
De–energisation during business hours – urban/short rural feeders	–3.20%	81.20	84.05	87.18	90.70	94.45
De–energisation during business hours – long rural/isolated feeders	19.88%	470.63	487.18	505.32	525.70	547.45
Re–energisation during business hours – urban/short rural feeders	–6.35%	64.57	66.84	69.33	72.12	75.11
Re–energisation during business hours – long rural/isolated feeders	19.64%	438.62	454.05	470.96	489.96	510.22
Re–test at customer's installation during business hours – urban/short rural feeders	17.69%	282.38	292.31	303.19	315.42	328.47
Re–test at customer's installation during business hours – long rural/isolated feeders	20.44%	564.75	584.62	606.39	630.85	656.94
Supply abolishment during business hours – urban/short rural feeders	19.88%	282.38	292.31	303.19	315.42	328.47
Supply abolishment during business hours – long rural/isolated feeders	21.15%	564.75	584.62	606.39	630.85	656.94
Temporary builders supply, not in permanent position– single phase metered – business hours – urban/short rural feeders	19.88%	470.63	487.18	505.32	525.70	547.45

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	21.15%	753.00	779.49	808.52	841.13	875.92
Temporary builders supply not in permanent position – multi phase metered – business hours – urban/short rural feeders	19.88%	470.63	487.18	505.32	525.70	547.45
Temporary builders supply not in permanent position – multi phase metered – business hours – long rural/isolated feeders	21.15%	753.00	779.49	808.52	841.13	875.92
Restoration of supply required due to customer action, during business hours – urban/short rural feeders	17.69%	282.38	292.31	303.19	315.42	328.47
Restoration of supply required due to customer action, during business hours – long rural/isolated feeders	20.44%	564.75	584.62	606.39	630.85	656.94
Wasted truck visit – one person crew – urban/short rural feeders	–13.99%	44.47	46.03	47.75	49.67	51.73
Wasted truck visit – one person crew – long rural / isolated feeders	2.26%	177.88	184.13	190.99	198.69	206.91
Wasted truck visit – two person crew – urban/short rural feeders	7.65%	93.38	96.67	100.27	104.31	108.63
Wasted truck visit – two person crew – long rural / isolated feeders	18.91%	373.53	386.67	401.07	417.24	434.50

Source: Ergon Energy, response to information request, 5 May 2010.

L. 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, or 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 next regulatory control period to ensure compliance with the distribution 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.

Further, the AER will require the Qld DNSPs to provide regulatory accounts, consistent with their respective approved cost allocation methodologies, on an annual basis. The AER intends to collect this information using a Regulatory Information Instrument.

Information contained in the table below has been drawn from the chapters in this decision.

Table L.1: Annual reporting requirements

Chapter	Reporting requirement	Purpose
Classification of services – chapter 2, appendix A	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.

Chapter	Reporting requirement	Purpose
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.
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 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 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.

Chapter	Reporting requirement	Purpose
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 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.
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.

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.
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 17.3.3. 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 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 18.3.5.	Demonstrate compliance with the price cap control mechanisms.

Chapter	Reporting requirement	Purpose

Self insurance – Appendix H	The following information is required for each self insurance event that occurred during the regulatory year:
	• 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.

M. Submissions

The AER received submissions on the draft decision and Qld DNSPs' revised regulatory proposals from the following interested parties:

Cement Australia Pty Ltd

Energex

EnergyAustralia

Energy Users Association of Australia (2)

Maryborough Sugar Factory

Queensland Council of Social Service

Queensland Minister for Energy

Total Environment Centre