Final decision

South Australia

distribution determination 2010–11 to 2014–15

May 2010

AUSTRALIAN ENERGY REGULATOR

Contents

Shortened forms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
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, South Australia draft distribution determination 2010–11 to 2014–15*, 25 November 2009
EMS	Energy and Management Services
ESCOSA	Essential Services Commission of South Australia
ESPIC	Electricity Supply Planning Industry Council
MMA	McLennan Magasanik Associates
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

Overview

Introduction

Under the National Electricity Law (NEL) and the NER, the AER is responsible for the economic regulation of electricity distribution services provided by distribution network service providers in the National Electricity Market.

This is the first electricity distribution determination made by the AER on the price control regime to apply to ETSA Utilities. The previous determination that applied to ETSA Utilities for the period 2005–2010 was made by the Essential Services Commission of South Australia (ESCOSA).

In making its decision and distribution determination, the AER has taken into account ETSA Utilities' revised regulatory proposal, submissions from interested parties, advice from consultants and updated economic information and forecasts.

The AER's determination for ETSA Utilities provides for distribution charges to increase by an average of 9.5 per cent per year in nominal terms over the next five years. This increase in network charges will flow through retail electricity prices to residential customers. A price rise of 6 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 3.4 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.

Key expenditure drivers and considerations

Energy use patterns in South Australia are a significant factor contributing to network expenditure over the next regulatory control period. The need to ensure that the network can withstand customer demands at peak times is contributing to the increase in network costs, driven predominantly by the use of air conditioners during summer heatwaves. This is despite customers consuming less energy, on average, as a result of a number of energy efficiency programs and increased penetration of photovoltaic systems. For example, over ETSA Utilities' network, maximum demand is forecast to grow on average by 2.4 per cent per year, while energy sales are forecast to decline by an average of 0.7 per cent per year over the next regulatory control period. The outcome is that the revenue required for ETSA Utilities to maintain the integrity of the network, supply reliability and services to customers over the 2010–15 regulatory control period is applied to a smaller volume of energy sold.

The AER has accepted ETSA Utilities' maximum demand forecasts included in the revised regulatory proposal, however, the AER is not satisfied that the energy sales forecast provides a realistic expectation of the demand forecast required to achieve the capital and operating expenditure objectives. The AER considers that ETSA Utilities' revised total energy sales forecast over the regulatory control period is understated by around five per cent. However, the energy sales forecast adopted by the AER is considerably lower than what was expected in the draft decision and reflects updated estimates for economic activity and energy use in South Australia. As noted below, this also has an impact on the level of network charges.

Revenue allowance

The AER has established the annual revenue requirement for ETSA Utilities based on the AER's approved capital and operating expenditure allowances. ETSA Utilities' total revenue for the 2010–15 regulatory control period is $3525 million (nominal).

This revenue allowance comprises in the main a return on capital, return of capital (depreciation), operating expenditure, and a tax allowance. It also includes a capital expenditure carry over from the 2005–10 regulatory control period. The return on capital and depreciation represents over 60 per cent of the revenue allowance, with operating expenditure accounting for 32 per cent and the tax allowance 5 per cent.

ETSA Utilities' allowed revenues will increase in nominal terms by 13 per cent in 2010–11 compared to the preceding year. For the remaining four years of the regulatory control period, ETSA Utilities revenues will increase in nominal terms by an average of 7 per cent per annum. If the weighted average cost of capital parameters had remained the same as those applied in the current regulatory control period the increase in ETSA Utilities' revenue in 2010–11 would be about 10 per cent lower. The significant annual increases in revenues over the 2010–15 regulatory control period are explained largely by the increasing capital expenditure program and higher operating expenses associated with a growing but aging network.

Network charges

In nominal terms, ETSA Utilities' distribution charges will increase by 15 per cent in 2010–11 compared to the preceding year and by 8.4 per cent in the subsequent years of the regulatory control period. This is a reduction to the distribution charges sought by ETSA Utilities, which would have resulted in an increase of 18.5 per cent in 2010–11, 8.6 per cent in 2011–12 and 13.3 per cent in the remaining years of the regulatory control period.

The final distribution charges were affected by an updated, 7 per cent lower, energy sales forecast provided by the Australian Energy Market Operator which has resulted in an increase in distribution charges compared to the AER's draft decision.

The precise effect on retail charges will not be clear until ETSA Utilities submits its pricing proposal following the AER's decision. The increases in 2010–11 will need to be adjusted as ETSA Utilities has over recovered revenue in the last year of the current regulatory control period and has to return the money to customers through lower tariffs.

The specific circumstances faced by ETSA Utilities which justify these price increases are discussed in this decision. Briefly, based on the typical residential customer's annual retail electricity charges of $1400 in 2009–10, and without the above adjustment, that customer can expect to pay 6 per cent or around $84 more in charges in 2010–11. Beyond 2010–11, further price rises for residential customers will be around 3.4 per cent or $52 each year. It should be noted that factors other than distribution charges will influence the level of retail prices including changes in wholesale electricity prices.

The increase in retail electricity charges in the first year is a result of the substantial increase in allowed capital and operating expenditure, and higher cost of capital than in the current regulatory period.

Capital and operating expenditure

In its draft decision the AER confirmed the need for an increase in capital works expenditure for ETSA Utilities over the next regulatory control period, with capacity augmentation and customer related expenditure being significant components of the capital works required over this period.

This increase in expenditure, driven by the continuing growth in peak demand, customer numbers and ageing assets over the next regulatory control period, has been confirmed by the AER's consideration of ETSA Utilities' revised proposal, submissions from interested parties, further advice from consultants and updated economic information and forecasts. While the AER is satisfied that an increase in expenditure is required, consistent with its draft decision, it does not consider that ETSA Utilities has justified the full extent of its capital expenditure proposal.

In the draft decision, the AER reduced ETSA Utilities' net forecast capital expenditure allowance to $1819 million (a reduction of 28 per cent compared to its original proposal). In response to the matters raised in the draft decision, ETSA Utilities revised its forecast capital expenditure for the next regulatory control period to $1985 million (nominal).

After assessing ETSA Utilities' revised regulatory proposal against the capital expenditure criteria in chapter 6 of the NER, and taking into account the advice of its consultants, the AER has accepted some elements of ETSA Utilities' revised forecasts for the low voltage capacity upgrade program, certain asset replacement expenditure and the network control project. Nevertheless, the AER considers that ETSA Utilities' proposed capital expenditure is still $217 million greater than an efficient level.

The AER's determination results in an 11 per cent reduction in ETSA Utilities' proposed revised capital expenditure and is also three per cent lower than the AER's draft decision. The further reduction in total allowed net capital expenditure compared to the draft decision is driven by changes in cost escalation rather than additional reductions to the scope of the capital expenditure work programs.

In particular, the AER considers that expenditure for the low voltage network upgrade program, asset replacement, the network control project and the substation security and fencing program proposed by ETSA Utilities in the revised proposal do not reflect efficient costs.

The draft decision did not approve ETSA Utilities' proposed operating expenditure allowance. ETSA Utilities' operating costs largely relate to network maintenance with increased inspections and higher emergency response expenditure forecast due to increasing asset age and growth in the network. The AER determined that the efficient allowance was 11 per cent lower than proposed. The AER determined that certain operating costs, such as vegetation management and non-operating cost allowances like self insurance and debt and equity raising costs were not efficient.

In the draft decision, the AER reduced ETSA Utilities' forecast operating expenditure allowance to $1091 million (nominal). In response to the matters raised in the draft decision, ETSA Utilities submitted a revised regulatory proposal which incorporated most aspects of the AER's draft decision and revised its forecast operating expenditure to $1166 million (nominal).

After assessing ETSA Utilities' revised proposal against the operating expenditure criteria in chapter 6 of the NER, the AER considers that ETSA Utilities' proposed operating expenditure is $51 million greater than an efficient level. The AER's determination of $1115 million (nominal) results in a 4.3 per cent reduction in forecast operating expenditure.

In particular, the AER considers that the following aspects of the operating expenditure proposal do not reflect prudent and efficient costs:

- the application of the economies of scale escalation for network growth to the operating expenditure in relation to emergency response activities
- the impact of ETSA Utilities' ageing network on maintenance and repair and emergency response operating expenditure
- the debt raising costs
- the self insurance allowance.

The approved operating expenditure includes the reclassification of some self insurance costs that the AER considers should have been included in ETSA Utilities' controllable operating expenditure. The AER has accepted that certain business as usual costs, which were included within ETSA Utilities' self insurance proposal are acceptable, however, were not suitable for self insurance. This has resulted in the reclassification of $23 million in proposed self insurance costs to controllable operating expenditure.

The AER was also not satisfied that the materials and labour cost escalators used to forecast capital and operating expenditures reflected current economic conditions and considered that the escalators used by ETSA Utilities were likely to overstate future costs. The AER 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 9.76 per cent for ETSA Utilities. This is approximately 30 basis points lower than in the draft decision. The AER has not accepted ETSA Utilities' revised proposal to maintain the imputation credit factor (gamma) at 0.5. The revised WACC is based on more recent financial market conditions which reflect 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 also implements three incentive schemes:

- the service target performance incentive scheme – which encourages ETSA Utilities to maintain or improve its service performance in terms of the number and incidence of outages on their network

- the efficiency benefit sharing scheme – which is designed to provide a fair sharing of operating cost efficiency benefits and losses between ETSA Utilities and network users

- the demand management incentive scheme – which is designed to provide incentives for ETSA Utilities to pursue and implement efficient non-network solutions to address growing demand on its network.

Alternative control services

Arrangements for establishing metering charges are also provided for in the decision. This is a result of the AER's decision to classify alternative control metering services to facilitate competition by reducing the barriers to entry faced by other providers of metering services in the South Australian market. This is the first time that a separate, weighted average price cap control mechanism is to be applied to metering services provided by ETSA Utilities and will result in these charges being unbundled from the distribution use of system charges, leading to a more cost reflective and transparent pricing outcome for customers.

Review process

The AER's distribution determination for the South Australian electricity DNSP, ETSA Utilities, for the 2010–2015 regulatory control period has been made under the relevant provisions of the NER and NEL. The AER must also consider a number of transitional requirements for South Australia that are set out in chapters 9 and 11 of the NER.

The AER released its draft decision for ETSA Utilities in November 2009. ETSA Utilities submitted its revised regulatory proposal in January 2010 indicating where it did not agree with the draft decision. The AER received a total of 20 submissions on the draft decision and ETSA Utilities' revised regulatory proposal. The AER's consideration of these submissions forms part of this decision.

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

The AER's detailed examination of ETSA Utilities' regulatory proposal and revised regulatory proposal was informed by advice from Parsons Brinckerhoff Strategic Consulting (PB). In addition to PB, the AER also engaged Energy Management Services to review the deliverability of ETSA Utilities' regulatory proposal and sought the assistance of the Australian Energy Market Operator in reviewing ETSA Utilities' demand and energy sales forecasts.

In making its distribution determination, the AER assessed ETSA Utilities' regulatory proposal to determine if it was in accordance with the requirements of the NER.

Expert engineering consultants, as well as financial and economic experts assisted the AER in making its assessment. The AER also considered the past performance of ETSA Utilities and the effectiveness of their policies and procedures, both in terms of past performance and in the development of its regulatory proposal.

Summary

Introduction

The Essential Services Commission of South Australia (ESCOSA) made the current regulatory determination for ETSA Utilities for a five year period from 1 July 2005 to 30 June 2010 (the current regulatory control period). ETSA Utilities owns and operates the electricity distribution network in South Australia.

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

This decision should be read in conjunction with the draft decision, together with consultants' reports. Except as specified in this decision, the AER confirms its conclusions set out in the draft decision.

The AER engaged the following consultants to assist in the assessment of ETSA Utilities' revised regulatory proposal:

- Parsons Brinckerhoff Strategic Consulting (PB)
- Australian Energy Market Operator (AEMO)
- 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).

The consultants' reports are available on the AER's website.

The key decisions addressed in this decision are:

- classification of services
- specification of the control mechanisms and methodologies for demonstrating compliance with the control mechanism
- the opening regulatory asset base (RAB) value
- 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 negotiation framework and NDSC that will apply to ETSA Utilities
- the schemes to provide incentives to ETSA Utilities 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 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 ETSA Utilities 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 to set the X factor for each year of the regulatory control period
- set out the form of control 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 for ETSA Utilities’ distribution services. The AER’s procedure for assigning and reassigning customers to tariff classes for ETSA Utilities was set out in appendix B of the draft decision.

The AER considered that while retailer of last resort services in South Australia are currently classified as excluded distribution services, these services did not fall within the definition of a distribution service in the NER.

Revised regulatory proposal

ETSA Utilities incorporated the classification of services as set out in the draft decision. However, it proposed a separate alternative control service, *meter customer exit fee*, to recover asset related and administrative costs associated with a meter being replaced by that of a another meter provider. ETSA Utilities stated that this new service is a consequence of it implementing variable standard small customer metering services and exceptional cases of large customer metering services as alternative control services.

ETSA Utilities accepted the AER's procedure for assigning or reassigning customers to tariff classes.

AER decision

The AER amended its classification of services to specify that the meter provision services classified as an alternative control service could include an exit fee. The AER's distribution service classifications are set out in appendix A to this decision.

The AER's procedure for assigning and reassigning customers to tariff classes for ETSA Utilities remains unchanged from the draft decision and is set out in appendix B of this decision.

Arrangements for negotiation

AER draft decision

The negotiated distribution service criteria (NDSC) applying to ETSA Utilities for the next regulatory control period was in appendix C of the draft decision.

The AER did not approve the negotiating framework proposed by ETSA Utilities. The AER required amendments to ETSA Utilities' negotiating framework were set out in appendix D of the draft decision.

Further, while not requiring specific amendment, the AER stated that publication of a price list by ETSA Utilities is to be undertaken outside of the negotiating framework and should be expressed to be indicative only. The AER considered that a set list of prices is inconsistent with the notion that negotiated distribution services are by definition negotiable.

The AER considered that regardless of how certain negotiated distribution services are grouped in ETSA Utilities' negotiating framework, the provisions of the negotiating framework must meet the minimum requirements provided under clause 6.7.5(c) of the NER for all negotiated distribution services.

Revised regulatory proposal

ETSA Utilities submitted a revised negotiating framework which maintained the approach of categorising services into two groups and structuring the negotiating framework around these groups. However, for one of these groups – price list services, the price list is expressed as being indicative only. Further, ETSA Utilities removed the pricing principles and connections arrangements adapted from chapter 3 of the *South Australian Electricity Distribution Code*.

ETSA Utilities stated its amendments will significantly impact on the resources required to negotiate the provision of negotiated distribution services, particularly with regard to new and non–standard or upgraded connection services. ETSA Utilities stated additional capex is required to fund the increased resources required to negotiate these distribution services under the negotiating framework. It proposed $1.2 million ($2008) per annum in forecast capex.

AER decision

Negotiated distribution service criteria

The NDSC applying to ETSA Utilities for the next regulatory control period are unchanged from the draft decision and are set out in appendix C of this decision.

Negotiating framework

The AER does not approve the revised negotiating framework proposed by ETSA Utilities. The AER considers that further amendments to ETSA Utilities' negotiating framework are necessary to enable it to be approved in accordance with the NER. The required amendments are as follows:

1. amendment to table 3 – timetable for indicative price list services to address clause 6.7.5(c)(2) of the NER, by providing that commercial information is to be as 'reasonably' required by ETSA Utilities to enable it to make an offer to the applicant.
2. amendment to section 16 – payment of ETSA Utilities' application fee. To address clause 6.7.5(c)(7) of the NER, section 16 needs to adequately clarify the arrangements for payment of application processing expenses. A footnote needs to be added to clarify that no new application fee is require after negotiations have been suspended.
3. amendment to clause E – Preamble to address clause 6.7.5(c)(6) by noting that disputes are to be dealt with in accordance with the relevant dispute provisions of the NEL as well a the NER.

The AER has amended ETSA Utilities revised negotiating framework in accordance with these requirements and the amended negotiating framework is at appendix D of this decision.

ETSA Utilities' claim for additional capex to fund the negotiating arrangements was assessed and rejected under the AER's review of ETSA Utilities' total capex proposal.

Control mechanisms for standard control services

AER draft decision

The AER accepted ETSA Utilities' proposal that a weighted average price cap (WAPC) be applied to its standard control services for the next regulatory control period. The AER did not accept ETSA Utilities' proposal to forecast an amount for transitional factors as a building block component rather than an annual adjustment.

The AER accepted ETSA Utilities' proposal to recover transmission use of system (TUOS) costs in a manner consistent with the approach used by the NSW DNSPs. The AER did not accept ETSA Utilities' proposal for a within period interest charge on TUOS payments.

Revised regulatory proposal

ETSA Utilities proposed three changes to the control mechanism in the draft decision:

- the retention of a term in the WAPC and side constraint formulas, to accommodate any foregone revenue adjustment under Part B of the demand management incentive scheme (DMIS)
- the tariff classes applicable to the side constraint formula
- a mechanism to recover working capital, to fund TUOS payments.

AER decision

The AER has reinstated the term for forgone revenue adjustment under Part B of the DMIS in the WAPC and side constraint formulae but the term will have no effect in the next regulatory control period.

The AER understands that ESCOSA will amend ETSA Utilities' distribution licence and require it to undertake a specific demand management project to account for any unspent demand management allowance. Accordingly, reference to an adjustment in relation to the ESCOSA's demand management allowance has been removed from the definition of the transition factor term in the WAPC and side constraints formulae.

The AER accepts ETSA Utilities' proposed tariff classes as set out in its revised regulatory proposal. The AER confirms its rejection of ETSA Utilities' proposal for an additional interest charge on its TUOS payments for cash flow timing issues.

Opening regulatory asset base

AER draft decision

The AER did not approve the inclusion of ETSA Utilities' proposed easement revaluation and the reinstatement of capital contributions removed by ESCOSA in the roll forward of the opening RAB. Metering assets associated with alternative control services were also removed from ETSA Utilities' RAB for standard control services.

The RAB roll forward calculations for ETSA Utilities provided for an opening RAB of $2768 million for standard control services for the next regulatory control period (as at 1 July 2010).

Revised regulatory proposal

ETSA Utilities proposed a revised opening RAB of $2903 million as at 1 July 2010, $134.7 million more than allowed in the draft decision.

ETSA Utilities updated the capex figures for 2008–09 and 2009–10 in its roll forward model (RFM). It also rejected the AER's adjustments to its RAB in respect of:

- valuation of easements
- ESCOSA's treatment of certain capital contributions.

AER decision

The AER accepts ETSA Utilities' updated capex for 2008–09 and 2009–10 in its RFM. However, the AER rejects the adjustments made by ETSA Utilities to its RAB in respect of the valuation of easements and ESCOSA's treatment of certain capital contributions.

The RAB roll forward calculations for ETSA Utilities are set out in table 1 and provide for an opening RAB of $2772.4 million for standard control services for the next regulatory control period (as at 1 July 2010).

Table 1: AER conclusion on ETSA Utilities' opening RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10[a]
Opening RAB	2504.9	2593.4	2628.9	2701.6	2767.0
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	149.4	122.5	119.9	170.0	193.5
Regulatory depreciation (adjusted for actual CPI)	–61.0	–87.0	–47.3	–104.6	–106.6
Closing RAB	2593.4	2628.9	2701.6	2767.0	2853.8
Difference between actual and forecast capex for 2004–05					–0.3
Return on difference					–0.2
Removal of metering assets					–81.0
Opening RAB at 1 July 2010					2772.4

(a) Based on estimated net capex.

Demand forecasts

AER draft decision

The AER accepted ETSA Utilities' proposed peak demand and customer number forecasts.

The AER considered that the energy sales forecasts proposed by ETSA Utilities did not provide a realistic expectation of the demand forecast. The AER considered that revising ETSA Utilities' forecast energy sales to the levels shown in table 2 provided a more realistic basis for determining the X factors under the weighted average price cap.

Table 2: AER draft conclusion on ETSA Utilities' peak demand, customer number and energy sales forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 [a]
Energy sales (GWh)	11 868	12 062	12 399	12 638	12 969	2.2%
Peak demand 10% PoE (MW)	3129	3227	3358	3434	3522	3.0%
Customer numbers	828 162	838 160	846 778	854 779	863 230	1.0%

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

Revised regulatory proposals

ETSA Utilities did not accept the draft decision on its energy sales forecast, and the AER's substitution of the energy sales forecast developed by AEMO.

ETSA Utilities raised concerns with AEMO's modelling approach, hot water sales forecasts, and the treatment of post model adjustments. ETSA Utilities provided a revised energy sales forecast (table 3) based on updated economic outlook and post model adjustments.

ETSA Utilities accepted the draft decision that its proposed peak demand and customer number forecasts provided a realistic expectation of demand forecast required to achieve the capex and opex objectives.

Table 3: ETSA Utilities energy sales forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 [a]
Energy sales (GWh)	11 144	11 185	10 934	10 714	10 481	–1.5%

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

AER decision

The AER considers the revised energy sales forecast proposed by ETSA Utilities does not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the NER. The AER considers revising ETSA Utilities' forecast energy sales to the levels shown in table 4 provides a more realistic basis for determining the X factors under the weighted average price cap.

The AER considers the peak demand and customer number forecasts proposed by ETSA Utilities provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives.

Table 4: AER conclusion on ETSA Utilities peak demand, customer numbers and energy sales forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 [a]
Energy sales (GWh)	11 636	11 543	11 416	11 354	11 318	–0.7%
10% PoE Peak demand (MW)	3159	3274	3361	3410	3477	2.4%
Customer numbers	828 162	838 160	846 778	854 779	863 230	1.0%

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

Forecast capital expenditure

AER draft decision

The AER was not satisfied ETSA Utilities' proposed net capex of $2315 million reasonably reflected the capex criteria. In particular, the AER considered:

- the proposed demand driven capex for the low voltage network upgrade program and major customer connections program did not reflect efficient costs
- ETSA Utilities' proposed asset replacement capex did not reflect efficient costs
- the proposed security of supply capex relating to the Kangaroo Island network security project and elements of the network control project were not demonstrated to be prudent and efficient
- ETSA Utilities' proposed safety related capex for the substation security fencing program and CBD aged asset replacement program did not reflect efficient costs
- the capex relating to superannuation and benchmark equity raising costs did not reflect efficient costs
- ETSA Utilities' application of cost escalators did not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives.

Following the adjustments required to address the AER's concerns, the AER was satisfied an estimate of $1628 million for ETSA Utilities' forecast net capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered these adjustments were the minimum necessary to ensure ETSA Utilities' capex forecast met the capex criteria.

Revised regulatory proposal

ETSA Utilities' revised regulatory proposal included a net capex allowance of $1793 million ($2009–10) for the next regulatory control period. ETSA Utilities' revised capex proposal is set out in table 5.

Table 5: ETSA Utilities' original and revised net capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Original net capex[a]	393.7	485.3	475.3	454.1	440.4	2248.9
Revised net capex	352.5	392.9	351.8	350.1	345.6	1792.8
Difference	–41.3	–92.4	–123.5	–104.1	–94.8	–456.1

Note: Totals may not add due to rounding.
(a) Excludes alternative control metering capex of $66.3 million.

ETSA Utilities implemented the findings of the draft decision in respect of forecast capex except in relation to the following areas:[1]

- the low voltage network upgrade program
- asset replacement expenditure
- substation fencing and security expenditure
- network control expenditure
- equity raising costs.

ETSA Utilities also included an additional capex requirement related to resources for implementing the negotiating framework for customer connections.

AER decision

Following its review of ETSA Utilities' revised capex proposal, the AER is not satisfied that the proposed forecast capex allowance reasonably reflects the capex criteria. The AER made the following adjustments:

- $39 million reduction to the low voltage capacity upgrade program to reflect a revised scope for required transformer augmentations
- $93 million reduction to asset replacement capex to reflect amended forecasting methodologies and a revised scope across a number of expenditure categories
- $2 million reduction to security of supply capex to reflect the exclusion of inefficient expenditure from the network control project
- $6 million reduction to safety capex to reflect a revised scope for the substation security and fencing program
- $6 million reduction to customer connection capex to reflect the exclusion of proposed costs associated with the revised negotiating framework for negotiated distribution services

1 ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 83–108.

- $43 million reduction to reflect the application of amended input cost escalators.

Allowing for the adjustments listed above, the AER's estimate of forecast net capex for ETSA Utilities is $1588 million, as set out in table 6. The AER considers these adjustments to be the minimum necessary to ensure ETSA Utilities' capex forecast meets the capex criteria.

Table 6: AER conclusion on ETSA Utilities' forecast capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities revised proposed net capex[a]	337.0	392.9	351.8	350.1	345.6	1777.3
Adjustment to demand driven capex	–7.7	–7.9	–7.9	–7.9	–7.9	–39.3
Adjustment to asset replacement capex	–15.8	–20.4	–18.9	–19.0	–18.4	–92.5
Adjustment to security of supply capex	–2.4	–	–	–	–	–2.4
Adjustment to safety capex	–2.3	–2.6	–1.0	–0.6	0.1	–6.4
Adjustment to customer connection capex	–1.2	–1.2	–1.2	–1.3	–1.3	–6.3
Adjustment to cost escalators	–6.1	–13.1	–10.0	–7.7	–6.0	–42.8
AER capex allowance	301.4	347.7	312.9	313.6	312.1	1587.7

Notes: Totals may not add due to rounding.
(a) Excludes proposed equity raising costs. The AER will allow ETSA Utilities to amortise a total amount of $8.6 million ($2009–10) in benchmark equity raising costs for the next regulatory control period.

Forecast operating expenditure

AER draft decision

The AER was not satisfied that the total opex forecast proposed by ETSA Utilities of $1175 million reasonably reflected the opex criteria, including the opex objectives. In establishing the opex allowance the AER made the following adjustments:

- $0.3 million reduction to maintenance and repair opex
- $5.0 million reduction to reflect a revised network growth escalator
- $0.01 million reduction to reflect revised network access, monitoring and control opex to remove the impact of the growth in work volume or network growth
- $20 million reduction to maintenance and repair and emergency response opex
- $4.8 million reduction to vegetation management

- $11 million reduction to emergency response opex
- $3.3 million reduction to sponsorships and community engagement projects
- $1.6 million reduction to reflect adjusted workload escalator
- $38 million reduction to reflect revised real input cost escalators
- $33 million reduction to the forecast self insurance opex
- $14 million reduction to the forecast for debt raising costs.

Following the adjustments required to address the AER's concerns, the AER was satisfied an estimate of $1044 million for ETSA Utilities' forecast opex reasonably reflected the opex criteria, taking into account the opex factors. The AER considered these adjustments were the minimum necessary to ensure ETSA Utilities' opex forecast satisfied the opex criteria.

Revised regulatory proposal

ETSA Utilities did not accept the AER's conclusion on opex, and included an opex forecast of $1082 million ($2009–10) in its revised regulatory proposal.

ETSA Utilities proposed adjustments to the draft decision relating to:

- escalation of emergency response opex
- trade off for asset replacement
- asset age escalation
- network growth escalation
- self insurance
- debt raising costs
- feed-in tariffs
- input cost escalators, including network growth escalation.

AER decision

The AER reviewed ETSA Utilities' proposed forecast controllable opex allowance and is not satisfied that the proposed forecast opex allowance reasonably reflects the opex criteria of the NER. The AER has determined the following specific adjustments to ETSA Utilities' revised proposed forecast opex:

- $7.2 million reduction to emergency response opex to reflect a change in the economies of scale factor to be applied to the network growth escalator for emergency response

- $3.3 million reduction to maintenance and repair and emergency response to remove the proposed impact of asset age on forecast maintenance
- $19.7 million reduction to reflect revised real input cost escalators
- $8.3 million reduction to the revised forecast self insurance opex
- $10.2 million reduction to the revised cost for debt raising costs.

Allowing for the adjustments listed above, the AER's estimate of controllable opex for ETSA Utilities is $1033 million, as set out in table 7.

Table 7: AER conclusion on ETSA Utilities total opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities' proposed forecast opex	199.5	207.7	215.8	226.4	232.3	1081.7
Adjustments to controllable opex	–1.0	–1.5	–2.0	–2.7	–3.3	–10.5
Adjustments to self insurance	–1.5	–1.6	–1.7	–1.7	–1.8	–8.3
Adjustment to debt raising costs	–1.9	–2.0	–2.0	–2.1	–2.2	–10.2
Adjustment to cost escalators	–1.9	–3.2	–4.2	–5.0	–5.5	–19.7
AER opex allowance	193.2	199.4	205.9	214.9	219.5	1032.9

Note: Totals may not add due to rounding.

Estimated corporate income tax

AER draft decision

The AER considered that ETSA Utilities' proposed tax remaining and tax standard asset lives were appropriate. It also considered ETSA Utilities' proposed opening tax asset base to be appropriate and reasonable, subject to the removal of metering assets used for alternative control services. The AER accepted that gifted assets should be included in the tax calculation.

The AER considered ETSA Utilities' regulatory proposal and the supporting information provided did not constitute persuasive evidence for justifying a departure from a gamma of 0.65 as specified in the AER's *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 against the AER's specified criteria.

Using these inputs, the AER used the PTRM to calculate the allowance for corporate income tax of $167 million over the next regulatory control period.

Revised regulatory proposal

ETSA Utilities proposed a total tax allowance of $254 million for the next regulatory control period. This revised allowance reflected changes by ETSA Utilities to various factors that affect revenues and costs. ETSA Utilities stated that it had not revised the transitional methodology used to determine corporate income tax under a post-tax regulatory approach from that contained in its regulatory proposal.

ETSA Utilities rejected the draft decision to apply a gamma of 0.65 to the calculation of corporate income tax. ETSA Utilities proposed a gamma of 0.5.

AER decision

McGrathNicol was engaged by the AER to identify and assess any significant changes in ETSA Utilities' tax approach from the draft decision. Based on McGrathNicol's assessment, the AER considers that the tax inputs into ETSA Utilities' PTRM and RFM are consistent with the tax provisions of the NER.

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 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 allowances for corporate income tax determined by the AER are presented in table 8. These figures are calculated using the PTRM and based on the various inputs to the model.

Table 8: AER conclusion on ETSA Utilities corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	32.3	32.6	32.0	33.6	34.6	165.2

Depreciation

AER draft decision

The AER assessed the remaining and standard asset lives used by ETSA Utilities as inputs to its PTRM, and the resulting regulatory depreciation allowance. The AER accepted the remaining and standard asset lives proposed by ETSA Utilities, except for the standard life for office equipment.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER determined ETSA Utilities' regulatory depreciation allowance of $640 million for the next regulatory control period. This figure reflected the removal of metering assets used for alternative control services from the RAB.

Revised regulatory proposal

ETSA Utilities proposed a total regulatory depreciation allowance of $636 million for the next regulatory control period. ETSA Utilities stated that its revised depreciation allowance reflected responses to matters raised in the draft decision. In particular, ETSA Utilities stated that its revised depreciation allowance (compared to the allowance in the draft decision) includes the impact of changes to:

- the opening RAB to correct for the treatment of certain capital contributions
- forecast capex.

AER decision

On the basis of the AER's approved asset lives, opening RAB, and forecast capex allowance, the AER determined ETSA Utilities' regulatory depreciation allowances for the next regulatory control period, as set out in table 9.

Table 9: AER conclusion on ETSA Utilities' regulatory depreciation ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014-15	Total
Regulatory depreciation	100.2	113.3	126.8	142.5	157.7	640.5

Note: Regulatory depreciation represents the net effect of the straight line depreciation of ETSA Utilities' assets and the indexation of those assets due to inflation.

Cost of capital

AER draft decision

The AER calculated an indicative nominal vanilla weighted average cost of capital (WACC) of 10.02 per cent for ETSA Utilities. The indicative WACC was higher than that proposed by ETSA Utilities because the nominal risk–free rate had increased since the time ETSA Utilities submitted its regulatory proposal.

Revised regulatory proposal

ETSA Utilities adopted a nominal vanilla WACC of 10.02 per cent consistent with the draft decision. In revising its WACC, ETSA Utilities adopted a market risk premium of 6.5 per cent and accepted the approach to estimate the debt risk premium by reference to the CBASpectrum fair value curve.

AER decision

The AER determines a nominal vanilla WACC of 9.76 per cent for ETSA Utilities. The WACC is based on the updated risk–free rate and debt risk premium, using the agreed averaging period. The inflation forecast has been updated based on the latest available RBA forecasts and targets. The other WACC parameters are based on the SORI.

Service target performance incentive scheme

AER draft decision

The AER determined the national service target performance incentive scheme (STPIS) would apply to ETSA Utilities in the next regulatory control period in the following form:

- the applicable components and parameters are the system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) reliability of supply parameters and the telephone answering customer service parameter
- overall revenue at risk of ±3 per cent including ±0.3 per cent for the telephone answering parameter
- the incentive rates to apply to each applicable parameter were set out in table 12.1 of the draft decision
- the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period were set out in table 12.2 of the draft decision
- the GSL component would not apply while the Essential Services Commission of South Australia's (ESCOSA) GSL scheme remained in place. In the event that the ESCOSA's GSL scheme is withdrawn the AER would implement such a scheme from the day the jurisdictional scheme is withdrawn.

The AER approved the use of the Box–Cox transformation method by ETSA Utilities for the purpose of setting the major event day boundary in the next regulatory control period. However, the AER rejected ETSA Utilities' proposal to apply a modified s–bank mechanism.

Revised regulatory proposal

ETSA Utilities considered the STPIS performance targets should be determined using the same period as that used to establish the ESCOSA's jurisdictional targets. This was considered by ETSA Utilities likely to be a period of five years.

AER decision

The AER determined it will apply the STPIS to ETSA Utilities. The AER will apply the SAIDI and SAIFI reliability of supply parameters and the telephone answering customer service parameter. There are no quality of supply parameters to apply.

The AER considered that it is not appropriate to use ETSA Utilities' alternative methodology for determining targets and maintains its position to set targets based on four years of data, that concludes with data from 2008–09. Therefore, the AER will apply the same performance targets to ETSA Utilities as those set out in the draft decision. The AER updated the incentive rates to apply to ETSA Utilities based on the amended revenues in this decision.

Efficiency benefit sharing scheme

AER draft decision

The AER decided it would apply the efficiency benefit sharing scheme (EBSS) in accordance with its final framework and approach for ETSA Utilities in the next regulatory control period. The AER considered that it would not adjust the EBSS for the consequences of changes in demand growth for ETSA Utilities for 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:

- 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 ETSA Utilities 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.

Revised regulatory proposal

ETSA Utilities maintained its original proposal in relation to the arrangements regarding the transition from ESCOSA’s efficiency carryover mechanism (ECM) to the EBSS. In particular, ETSA Utilities considered the aspects of the *ESCOSA Statement of Regulatory Intent* which include uncontrollable cost items within the EBSS and which apply a negative carryover amount, either immediately or on a deferred basis, are incorrect or invalid. ETSA Utilities stated the AER should:

- exclude the inclusion of uncontrollable cost items arising in the current regulatory control period from the carryover amount
- disregard any negative carryover amounts for the next regulatory control period which result from costs arising in the current regulatory control period.

AER decision

In the next regulatory control period the AER will apply the EBSS in accordance with its framework and approach for ETSA Utilities. The AER will not adjust the EBSS for the consequences of changes in demand growth for ETSA Utilities for the next regulatory control period. The AER will allow any negative opex carryover accrued in respect of the ECM in the current regulatory control period to be deferred to offset any positive carryover accrued in the next regulatory control period, provided the negative carryover is accrued in an approved uncontrollable cost category under the EBSS.

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 ETSA Utilities 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.

Demand management incentive scheme

AER draft decision

The AER decided to apply a two part demand management incentive scheme (DMIS) to ETSA Utilities. The DMIS will comprise of a Part A – DMIA component, and a Part B – foregone revenue component.

Part A will be capped at $3 million in the next regulatory control period. The capped amount will be allocated to ETSA Utilities as an ex–ante allowance, in five equal annual instalments of $600 000. The ex–post review and operation of the DMIA will be as set out in the DMIS. Part B is as set out in the DMIS and remains uncapped for projects approved in Part A.

Revised regulatory proposal

ETSA Utilities proposed the DMIA assessment criteria be modified to include a statement that projects submitted for approval would not be disallowed in the ex–post review should they not achieve the intended demand reduction or not do so in a timely manner. It considered there is scope for the AER to disallow projects that did not perform as intended.

ETSA Utilities proposed that the Part B – foregone revenue component be expanded to apply to any additional demand management project it undertakes in the next regulatory control period that does not form part of its revised proposal, whether undertaken within the scope of the DMIA or not. Further, it proposed that the DMIS be varied such that where the Part A cap has been met, projects can still be approved under Part A of the DMIS for the purposes of recovering foregone revenue in Part B of the DMIS.

AER decision

The AER confirms its position as set out in the framework and approach and draft decision, to apply the DMIS to ETSA Utilities. The DMIS will comprise of a Part A – DMIA component and a Part B – foregone revenue component.

Part A will be capped at $3 million in the next regulatory control period. The capped amount will be allocated to ETSA Utilities as an ex–ante allowance, in five equal instalments of $600 000. The ex–post review and operation of the DMIA will be as set out in the DMIS.

Part B will be uncapped but subject to the restrictions set out in the DMIS. Part B will be applied consistent with the methodology set out in the DMIS.

Pass through arrangements

AER draft decision

The AER accepted the following pass through events as nominated pass through events for ETSA Utilities:

- smart meter event
- carbon pollution reduction scheme event
- feed-in tariff event
- native title event
- a general nominated pass through event.

The AER considered the other events proposed by ETSA Utilities did not meet the AER's assessment criteria and therefore those events were not accepted as nominated pass through events.

For general nominated events the AER stated it 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 stated it will apply a materiality threshold of the administrative costs of assessing an application relating to specific nominated events.

Revised regulatory proposal

ETSA Utilities did not accept the position of the AER in relation to the following specific nominated pass through events:

- industry standards event – ETSA Utilities considered the AER had no legal basis to reject this nominated pass through event
- retailer failure event – ETSA Utilities did not consider the AER had accepted the high level of risk of retailer failure and noted that the Essential Services Commission of Victoria had included a pass through for this event in the current regulatory control period

- interim period event – ETSA Utilities considered that the AER has the legal capacity to make a decision to include this event.

ETSA Utilities proposed the following specific nominated pass through events:

- industry standards change event
- interim period event
- retailer failure event
- retailer of last resort obligation event
- Kangaroo Island cable failure event.

ETSA Utilities proposed a revised interpretation for the definition of a carbon pollution reduction scheme event.

AER decision

The AER accepts the following additional pass through events to apply to ETSA Utilities for the next regulatory control period:

- smart meter event
- carbon pollution reduction scheme event
- feed-in tariff event
- native title event
- retailer of last resort event
- general nominated pass through event

as defined in section 15.5 of this decision.

The AER considers the other events proposed by ETSA Utilities should not be nominated as specific nominated pass through events. However, if the event occurs, the AER notes that ETSA Utilities 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.

Building block revenue requirements

AER draft decision

The draft decision resulted in a total revenue requirement for the next regulatory control period of $3549 million, compared to $3720 million proposed by ETSA Utilities. The main reasons for the reduction were:

- the removal of the $243 million from ETSA Utilities' opening RAB
- the removal of the $638 million from ETSA Utilities' forecast capex
- the removal of the $131 million from ETSA Utilities' forecast opex.

The real price changes (as represented by the X factors) were significantly affected by the AER's revised energy forecasts. The real price increases where reduced by the higher energy forecasts, with ETSA Utilities' revenue requirement recovered over a greater volume of forecast energy consumption. The building blocks and the X factors are shown in table 10.

Table 10: AER draft decision on ETSA Utilities' annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	100.3	113.1	126.6	142.4	157.9
Return on capital	277.5	300.3	327.9	350.9	373.7
Opex	192.3	204.6	216.8	232.7	244.3
Tax allowance	31.9	33.0	32.4	34.0	35.2
Capex carryover	8.4	7.6	4.3	0.1	0.0
Annual revenue requirements	610.4	658.6	708.0	760.3	811.3
Expected revenues	616.4	653.2	703.9	756.8	818.4
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors (%)	–10.95	–3.90	–3.90	–3.90	–3.90

Note: Negative X factors represent a real price increase.

Revised regulatory proposal

ETSA Utilities proposed a total revenue requirement for the next regulatory control period of $3793 million, compared to $3549 million allowed in the draft decision. The components of ETSA Utilities proposed revenue requirement are shown in table 11.

Table 11: ETSA Utilities proposed annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	98.3	112.2	125.9	141.8	157.2
Return on capital	291.0	318.5	350.0	376.4	402.0
Opex	204.4	218.0	232.0	249.4	262.2
Tax allowance	49.0	50.4	49.4	51.6	53.3
Capex carryover	0	0	0	0	0
Annual revenue requirements	642.7	699.1	757.3	819.2	874.7
Expected revenues	615.7	666.0	744.7	840.9	949.7
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors (%)	–15.63	–5.96	–10.50	–10.50	–10.50

ETSA Utilities noted that the draft decision excluded the transition carryover effect from the building blocks. ETSA Utilities revised its PTRM in line with the draft decision. However, because ETSA Utilities anticipates a significant carryover to be returned to customers (an estimated $28 million in 2010–11), to derive a smooth price path for customers, the X factors in the first and second year of the next regulatory control period have been calculated such that a constant price increase of about 10.5 per cent is passed on to customers on average each year.

AER decision

The AER's decision results in a total revenue requirement for the next regulatory control period of $3525 million ($nominal), compared to $3793 million proposed by ETSA Utilities. The main reasons for the reduction are:

- the removal of $131 million from ETSA Utilities' opening RAB. This amount relates to the revaluations ETSA Utilities made to its RAB for easements and the reinstatement of capital contributions, and an updated CPI figure for 2009–10.
- the removal of $217 million from ETSA Utilities' forecast capex
- the removal of $51 million from ETSA Utilities' forecast opex
- the removal of $88 million from ETSA Utilities' proposed tax allowance, reflecting in part a higher gamma than that proposed by ETSA Utilities
- a lower WACC than that proposed by ETSA Utilities.

The AER conclusion on ETSA Utilities' annual revenue requirements and X factors based on its decisions regarding the building blocks is shown in table 12.

Table 12: AER conclusion on ETSA Utilities' annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	100.2	113.3	126.8	142.5	157.7
Return on capital[a]	270.5	292.7	318.5	339.8	360.7
Opex	197.9	209.6	221.8	237.4	248.7
Tax allowance	32.3	32.6	32.0	33.6	34.6
Capex carryover	8.6	7.9	4.5	0.4	0.0
Annual revenue requirements	609.6	656.1	703.6	753.7	801.7
Expected revenues	619.7	656.9	695.8	745.9	804.0
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors (%)	–12.14	–5.75	–5.75	–5.75	–5.75

(a) Includes equity raising costs.

In deciding on ETSA Utilities' X factors, the AER has not recognised the forecast impact of any carry over adjustments from the current regulatory period. Accordingly, the AER has adopted the approach used for the draft decision and applied a separate X factor (Po) for the first year of the next regulatory control period and then held the X factor constant for the remaining years of the next regulatory control period. Using this approach, the AER revised ETSA Utilities' X factor for 2010–11 from –15.63 per cent to –12.14 per cent, the X factor for 2011–12 from –5.96 per cent to –5.75 per cent and the X factors for the remaining years of the next regulatory control period from –10.50 per cent to –5.75 per cent.

The size of the X factors were significantly affected by the revised energy forecasts (as discussed in chapter 6), which lowered the expected per unit price increases.

The impact of the AER's decision on the X factors on end use prices, compared with ETSA Utilities' revised regulatory proposal, is outlined in table 13.

Table 13: Retail price impacts (%)

	2010–11	2011–12	2012–13	2013–14	2014–15
ETSA Utilities regulatory proposal					
Real impacts	6.3	2.4	4.2	4.2	4.2
Nominal impacts	7.4	3.5	5.3	5.3	5.3
AER decision					
Real impacts	4.9	2.3	2.3	2.3	2.3
Nominal impacts	6.0	3.4	3.4	3.4	3.4

Note: Calculations assume distribution network charges make up 40 per cent of retail electricity prices. Inflation of 2.52 per cent assumed for calculating the nominal impacts.

Alternative control services

AER draft decision

The AER stated it would apply a separate WAPC control mechanism set out in the framework and approach to alternative control services. The AER noted that ETSA Utilities' indicated that it may reconsider some of the assumptions underlying its proposal, however, it was also the case that stakeholders had no opportunity to comment on ETSA Utilities' proposal. The AER stated that it would assess the building block components of the control mechanism based on the revised regulatory proposal and submissions from interested parties.

The AER stated ETSA Utilities was required to demonstrate compliance with the WAPC by providing, as part of its pricing proposal, the proposed tariffs which correspond to the price terms contained in the WAPC formula approved by the AER.

Revised regulatory proposal

ETSA Utilities considered the draft decision classifying alternative control metering services to be inappropriate, but incorporated the alternative control metering services control mechanism consistent with the draft decision in its revised regulatory proposal. It also accepted that compliance with the control mechanism will be demonstrated by providing metering tariffs as part of its annual pricing proposal.

AER decision

The AER will apply a separate WAPC control mechanism to alternative control services, set out in section 17.4 of this decision. ETSA Utilities is required to demonstrate compliance with the WAPC by providing, as part of its pricing proposal, the proposed tariffs which correspond to the price terms contained in the WAPC formula approved by the AER.

The AER approved ETSA Utilities' proposal to adopt a reduced number of tariff components in the first year 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 Essential Services Commission of South Australia (ESCOSA) made the current regulatory determination for ETSA Utilities 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. ETSA Utilities owns and operates the electricity distribution network in South Australia.

The AER has made this decision and distribution determination for ETSA Utilities according to the relevant requirements of chapter 6 of the NER and the transitional requirements for South Australia contained in chapters 9 and 11 of the NER. The AER's principal task is to set the revenues that ETSA Utilities can recover or prices that ETSA Utilities can charge from the provision of direct control services in the period 1 July 2010 to 30 June 2015 (the next regulatory control period).

On 1 July 2009 ETSA Utilities submitted its regulatory proposal and proposed negotiating framework for the next regulatory control period to the AER. On 17 July 2009 the AER published these and its proposed negotiated distribution service criteria (NDSC) for ETSA Utilities. On 30 November 2009 the AER published its draft decision and draft distribution determination for ETSA Utilities.[2] In mid January 2010 ETSA Utilities submitted its revised regulatory proposal in response to the draft decision.[3] The revised regulatory proposal was published by the AER on 15 January 2010.

This decision and the distribution determination should be read in conjunction with the draft decision and draft distribution determination for ETSA Utilities.

1.1 AER draft decision

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

The draft decision resulted in a total revenue requirement for the next regulatory control period of \$3549 million, compared to \$3720 million proposed by ETSA Utilities. The main reasons for the difference between the AER's and ETSA Utilities' estimated total revenue requirement reflect the net effect of:

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[1] The AER uses the version of the NER that is in effect at the date the regulatory proposal is lodged. For the purposes of this decision and distribution determination for ETSA Utilities, the relevant version of the NER is version 30, which was in effect on 1 July 2009.

[2] AER, *Draft decision, South Australia draft distribution determination 2010–11 to 2014–15*, (Draft decision, SA draft distribution determination), 25 November 2009; and AER, *Draft distribution determination ETSA Utilities, 1 July 2010 – 30 June 2015*, 25 November 2009.

[3] ETSA Utilities, *ETSA Utilities revised regulatory proposal 2010–2015*, (Revised regulatory proposal), 14 January 2010.

- removal of the $243 million from ETSA Utilities' opening regulatory asset base (RAB)
- removal of the $638 million from ETSA Utilities' forecast capital expenditure (capex)
- removal of the $131 million from ETSA Utilities' forecast operation expenditure (opex)
- a higher weighted average cost of capital than proposed by ETSA Utilities.

The size of the X factors were also significantly affected by the revised energy forecasts, which lowered the expected per unit price increases. Table 1.1 shows the draft decision on ETSA Utilities building blocks and X factors.

Table 1.1: AER draft decision on ETSA Utilities' annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	100.3	113.1	126.6	142.4	157.9
Return on capital	277.5	300.3	327.9	350.9	373.7
Operating expenditure	192.3	204.6	216.8	232.7	244.3
Tax allowance	31.9	33.0	32.4	34.0	35.2
Capex carryover	8.4	7.6	4.3	0.1	0.0
Annual revenue requirements	610.4	658.6	708.0	760.3	811.3
Expected revenues	616.4	653.2	703.9	756.8	818.4
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors (%)	–10.95	–3.90	–3.90	–3.90	–3.90

Source: AER, *Draft decision, SA draft distribution determination*, November 2009, p. 419, table 16.5.

The AER determined ETSA Utilities' opening RAB to be $2768 million ($2009–10) as at 1 July 2010.[4] The total capex allowance used by the AER in the building block calculation was $1628 million ($2009–10).[5] The total opex allowance used by the AER in the building block calculation was $1044 million ($2009–10).[6]

4 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 416, table 16.3.
5 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 175, table 7.17.
6 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 245, table 8.20.

The AER specified the NDSC to apply to ETSA Utilities. The AER did not approve the negotiating framework proposed by ETSA Utilities and specified a number of required amendments to the negotiating framework in the draft decision.[7]

1.2 Revised regulatory proposal

ETSA Utilities set out an annual revenue requirement that increased from $643 million in 2010–11 to $875 million in 2014–15 (nominal), and a total annual revenue requirement of $3793 million for the next regulatory control period.[8] This is $72 million greater than its original annual revenue requirement of $3721 million.

ETSA Utilities' revised opening RAB was $2983 million (as at 1 July 2010). This compares to its original opening RAB of $3011 million (as at 1 July 2010). The revised RAB incorporated an updated capex forecast for 2009–10, and included an amount of $80 million for alternative control services. ETSA Utilities did not accept the draft decision on the opening RAB regarding the valuation of easements and ESCOSA treatment of capital contributions.[9]

ETSA Utilities' revised capex forecast for the next regulatory control period was $1793 million ($2009–10). This compares to its original capex forecast of $2315 million ($2009–10). ETSA Utilities implemented most aspects of the draft decision relating to forecast capex, except those relating to the determination of cost escalators.[10]

ETSA Utilities' revised forecast opex for the next regulatory control period was $1081 million ($2009–10). This compares to its original opex forecast of $1176 million ($2009–10). ETSA Utilities implemented most aspects of the draft decision relating to opex and has included a forecast for feed–in tariff payments. It has not implemented amendments relating to:[11]

- emergency response opex
- capex opex trade off
- cost escalation
- self insurance.

ETSA Utilities generally accepted the other elements of the draft decision, although some components, such as the control mechanism, demand management and pass through event definitions were amended in some respects.

ETSA Utilities provided revised forecasts of energy sales.[12]

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7 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 40–41.
8 ETSA Utilities, *Revised regulatory proposal*, p. 216.
9 ETSA Utilities, *Revised regulatory proposal*, p. 186.
10 ETSA Utilities, *Revised regulatory proposal*, p. 109.
11 ETSA Utilities, *Revised regulatory proposal*, p. 135.
12 ETSA Utilities, *Revised regulatory proposal*, chapter 5.

1.3 Review process

The AER reviewed ETSA Utilities' regulatory proposal and proposed negotiating framework 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 ETSA Utilities about the development of the regulatory information notice, pro forma templates and guidelines.

- Framework and approach—the AER consulted with ETSA Utilities and interested parties about the development of the classification of services, control mechanism, efficiency benefit sharing scheme (EBSS), demand management incentive scheme (DMIS) and service target performance incentive scheme (STPIS) to be applied in the distribution determination. The framework and approach was published in November 2008, as required under clause 6.8.1 of the NER.

- Cost allocation method—in February 2009 the AER approved cost allocation methods of ETSA Utilities under clause 6.15.4 of the NER.

- Regulatory proposal—ETSA Utilities submitted its regulatory proposal and proposed negotiating framework to the AER on 1 July 2009. The AER assessed ETSA Utilities' regulatory proposal against chapter 6 of the NER.

- Public consultation—the AER published ETSA Utilities' regulatory proposal and the AER's proposed NDSC on 17 July 2009 and called for submissions from interested parties. The AER held a public forum in Adelaide on ETSA Utilities' regulatory proposal on 6 August 2009, where ETSA Utilities and interested parties gave presentations.

- Submissions—the AER received 12 submissions on ETSA Utilities' regulatory proposal or the proposed NDSC. The submissions are listed in appendix M 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.[13] PB provided independent advice to the AER on these matters, based on its review. The AER considered this advice in making its draft distribution determination. The terms of reference guiding PB's review are an appendix to its report.

- Assessment by demand forecasting experts—the AER engaged the Australian Energy Market Operator (AEMO) as a technical expert to provide advice in relation to demand forecasts.

- Additional technical advice—the AER engaged Energy and Management Services (EMS) to provide technical and engineering advice throughout the review

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[13] PB is a group of engineering and business consultants with a primary focus on specialised needs and operations in electric power, gas and other allied sectors.

process.[14] EMS assisted the AER in reviewing the technical aspects of material contained in ETSA Utilities' proposal, submissions and PB's report.

- Other specialist advice—the AER also engaged Access Economics[15] 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 base for the post–tax revenue model.

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

- Public consultation—the AER held a public forum in Adelaide on 9 December 2009 to explain its draft decision and receive oral submissions from interested parties.

- Revised regulatory proposal—ETSA Utilities submitted its revised regulatory proposal to the AER on 14 January 2010. The AER published the revised regulatory proposal on 15 January 2010.

- Submissions—the AER received 20 submissions on its draft decision and draft distribution determination and ETSA Utilities' revised regulatory proposal. The submissions are listed at appendix L 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 proposal. The AER engaged EMS to provide additional technical advice. AEMO provided the AER with advice on energy sales forecasts in South Australia in response to ETSA Utilities' revised forecasts.

- 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 advise it on issues raised in relation to the estimation of gamma.

- Decision—the AER made its decision and distribution determination for ETSA Utilities on 4 May 2010.

1.4 Structure of decision

This decision sets out the AER's consideration of ETSA Utilities' revised regulatory proposal, together with the negotiating framework and NDSC to apply to ETSA Utilities. This decision includes consideration of substantive issues raised in

14 EMS is an engineering consulting firm.
15 Access Economics is an economic consulting firm that specialises in economic modelling, forecasting and policy analysis.

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
- chapter 17 sets out the control mechanism 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 ETSA Utilities. It also sets out the AER's classification of ETSA Utilities' distribution services for the next regulatory control period and the procedures to be used by ETSA Utilities 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 a transmission system or another distribution system.[16] Distribution services are classified as either direct control services, negotiated distribution services, or as unregulated distribution services.[17]

2.1 AER draft decision

The AER applied the classification of services set out in the framework and approach for ETSA Utilities' distribution services. The AER's procedure for assigning and reassigning customers to tariff classes for ETSA Utilities was set out in appendix B of the draft decision.[18]

The AER considered that while retailer of last resort (ROLR) services in South Australia are currently classified as excluded distribution services,[19] it considered that these services did not fall within the definition of a distribution service in the NER.[20]

2.2 Revised regulatory proposal

ETSA Utilities incorporated the classification of services as set out in the draft decision although it did not agree with the AER's reasons set out in the draft decision.

ETSA Utilities proposed a separate alternative control service, *meter customer exit fee*, to recover asset related and administrative costs associated with a meter being replaced by that of a another meter provider. It stated this new service is a consequence of it implementing variable standard small customer metering services and exceptional cases of large customer metering services as alternative control services.[21] ETSA Utilities accepted the AER's procedure for assigning or reassigning customers to tariff classes and will submit its documented procedure consistent with the draft decision along with its pricing proposal.[22]

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16 NER, chapter 10.
17 NER, clause 6.2.1(a).
18 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 24.
19 The ROLR is responsible for assuming the obligations under the NER (including the obligation to pay trading amounts and other amounts due under the NER) of a market customer that has defaulted in the performance of its obligations under the NER.
20 Matters relating to the ROLR functions are contained in the cost pass through section of the revised regulatory proposal and accordingly addressed in chapter 15 of this decision.
21 ETSA Utilities, *Revised regulatory proposal*, January 2009, pp. 26–27.
22 ETSA Utilities, *Revised regulatory proposal*, January 2009, p. 39.

2.3 Submissions

2.3.1 Classification of services

TRUenergy submitted that in principle it supports the AER's unbundling of metering services. However, it stated that system changes were required to transit to an unbundled environment and therefore requested that the AER defer the implementation until 1 July 2011.[23]

AGL Energy Ltd (AGL) stated that 'unbundling' network electricity charges provides transparency to customers, enabling them to make informed decisions on competitive offerings and that the 'bundled' approach is a potential barrier to the provision of contestable services.[24]

AGL also stated that a nationally consistent regulatory framework and a national set of metering procedures and rules were required, and that meter provision and meter data services should be subject to competition. It stated that while supporting the AER's approach, a transitional period is required to ensure all parties can make the necessary changes to implement the change.[25]

2.3.2 Assigning customers to tariff classes

The Energy Consumers Coalition of South Australia (ECCSA) submitted that the AER's approach to assigning customers to tariff classes does not address or require ETSA Utilities to comply with the requirements of clause 6.18.5(b) of the NER. ECCSA also submitted that setting tariffs that ensure long run marginal costs is the only method that customers are assured that tariff structures as a whole are cost reflective. It further stated that the AER should require ETSA Utilities to develop tariffs that capture the cost of providing short term peaks in demand.[26]

2.4 Issues and AER considerations

2.4.1 Classification of services

ETSA Utilities informed the AER that it was not requesting a specific service classification for the meter customer exit fee but only intended to propose the meter customer exit fee as a component of the alternative control tariff metering service tariff class.[27] The AER accepts this clarification of ETSA Utilities' revised regulatory proposal.

ETSA Utilities noted that the alternative control meter provision service definition in the draft decision was quite specific and that it could be considered as not contemplating an exit fee.[28] The AER acknowledges that ETSA Utilities is entitled to recover these charges in certain circumstances. For example, in the event a meter

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[23] TRUenergy, *South Australian draft distribution determination 2010–11 to 2014–15*, February 2010.
[24] AGL, *South Australia draft distribution determination 2010–11 to 2014–15*, February 2010, p. 1.
[25] AGL, *South Australia draft distribution determination 2010–11 to 2014–15*, February 2010, p. 2.
[26] ECCSA, *The AER draft decision on ETSA Utilities application*, February 2010, p. 52.
[27] ETSA Utilities, email response, 2 February 2010; and ETSA Utilities, letter, 15 February 2010.
[28] ETSA Utilities, email response, 2 February 2010.

supplied by ETSA Utilities to an alternative control meter customer is removed—while it still has some residual value included in the regulatory asset base—and replaced by a meter supplied by another meter provider, then it is reasonable for this residual value to be recovered via an exit fee.

One of the factors considered by the AER in classifying alternative control metering services is the direct attribution of the costs of service to the relevant customer.[29] The direct attribution principle means it is reasonable for a customer that stops receiving the alternative control metering service to contribute towards the residual value of the meter to ensure the cost is not borne by the remaining customers.

The AER therefore considers it reasonable to define the meter provision services classified as an alternative control service to include the replacement of an ETSA Utilities' meter by that of another meter provider. The AER has included the following definition in the direct control (alternative control) services section of appendix A (clause A.5 and A.6) of this decision:

> For the purposes of this clause, meter provision services include, but are not necessarily limited to, any asset related and administrative costs associated with the provision, installation, maintenance, and replacement of the meter (including circumstances in which ETSA Utilities meter is replaced by that of another meter provider).

The AER's consideration of the proposed exit fee is in chapter 17 of this decision as part of the weighted average price cap control mechanism for alternative control services.

AGL and TRUenergy supported the AER's classification of alternative control metering services but requested the implementation of the decision be deferred. ETSA Utilities also noted that the retailers had indicated that they were not in a position to implement billing system changes by 1 July 2010.[30] The alternative control metering service classification was set out in the framework and approach for ETSA Utilities.[31] The AER notes that a distribution determination is predicated on several constituent decisions but there are no constituent decisions that relate to billing and settlement matters.[32] The retailers concerns relate to practical issues associated with interactions between a DNSP and network users. The AER considers that practical implementation issues relating to billing and settlements are outside the scope of the distribution determination.

The AER acknowledges AGL's comments regarding a nationally consistent framework and competitive environment for metering services. The AER stated that in the absence of specific circumstances and varying levels of market maturity a consistent classification of metering services across the NEM would be achievable.[33] The AER notes that the Australian Energy Market Commission is currently

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29 NER, clause 6.2.2(c)(5).
30 ETSA Utilities, email, *Metering alternative control services*, 23 February 2010.
31 AER, *Final decision, Framework and approach paper 2010–15: ETSA Utilities*, November 2008.
32 NER, clause 6.12.1.
33 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 16.

considering a rule change proposal in relation to the provision of metering data services.[34]

2.4.2 Assigning customers to tariff classes

ECCSA's submission suggests that the AER has discretion and authority to review and determine the nature of tariff classes as part of its distribution determination. Clause 6.12.1 of the NER does not identify any constituent decisions that require the AER to determine tariff 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 merely 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 ECCSA relate to the revenue to be recovered from tariff classes and are applicable at the stage of reviewing a pricing proposal, not as part of the distribution determination.

2.5 AER conclusion

2.5.1 Classification of services

The AER has amended its classification of services to specify that the meter provision services classified as an alternative control service could include an exit fee. The AER's distribution service classifications are set out in appendix A of this decision.

2.5.2 Assigning customers to tariff classes

The AER's procedure for assigning and reassigning customers to tariff classes for ETSA Utilities remains unchanged from the draft decision and is set out in appendix B of this decision.[35]

2.6 AER decision

> In accordance with clause 6.12.1(1) of the NER, the classification of services to apply to ETSA Utilities is 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.

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[34] AEMC, *Rule changes: Provision of metering data services and clarification of existing metrology requirements*; available at http://www.aemc.gov.au/Electricity/Rule-changes/Open.html.

[35] The appendix has also been amended in three instances where the term tariff had been used instead of tariff class.

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, but are 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 (including price) of access for negotiated distribution services. The AER also applies the NDSC in resolving disputes regarding these terms and conditions.
2. negotiating framework—sets out the procedure to be followed during negotiations between a DNSP and any person wishing to receive a negotiated distribution service.

This chapter sets out the AER's considerations and conclusions on the negotiating framework and NDSC to apply to ETSA Utilities in the next regulatory control period.

3.1 AER draft decision

The NDSC applying to ETSA Utilities for the next regulatory control period was in appendix C of the draft decision.

The AER did not approve the negotiating framework proposed by ETSA Utilities.[36] The AER required amendments to ETSA Utilities' negotiating framework as set out in appendix D of the draft decision.

Further, while not requiring specific amendment, the AER stated in the draft decision that publication of a price list by ETSA Utilities is to be undertaken outside of the negotiating framework and should be expressed to be indicative only. The AER considered that a set list of prices is inconsistent with the notion that negotiated distribution services are by definition negotiable.[37]

The AER considered that regardless of how certain negotiated distribution services are grouped in ETSA Utilities' negotiating framework, the provisions of the negotiating framework must meet the minimum requirements provided under clause 6.7.5(c) of the NER for all negotiated distribution services.[38]

[36] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 41.
[37] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 41.
[38] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 36.

3.2 Revised regulatory proposal

3.2.1 Negotiated distribution service criteria

ETSA Utilities noted the AER's NDSC as set out in the draft decision and incorporated it into its revised proposed negotiating framework.[39]

3.2.2 Negotiating framework

ETSA Utilities submitted a revised negotiating framework which included a number of modifications.[40] Broadly, the revised negotiating framework maintained the approach of categorising services into two groups and structuring the negotiating framework around these groups. However, for one of these groups – price list services, the price list is expressed as being indicative only. Further, ETSA Utilities removed the pricing principles and connections arrangements adapted from chapter 3 of the South Australian *Electricity Distribution Code* (EDC).[41] The complete list of amendments made in response to the draft decision is provided in ETSA Utilities revised regulatory proposal.[42]

ETSA Utilities stated these amendments will significantly impact on the resources required to negotiate the provision of negotiated distribution services, particularly with regard to new and non-standard or upgraded connection services. ETSA Utilities stated it has previously employed a more prescriptive regime, under which prices were either fixed for high volume low cost distribution services, through a price list, or determined in accordance with chapter 3 of the EDC. ETSA Utilities stated the previous arrangement required little administrative effort in negotiating the charge/price for such services.[43]

ETSA Utilities stated additional capex is required to fund the increased resources required to negotiate these distribution services under the negotiating framework employed under the NER. It proposed $1.2 million ($2008) per annum in forecast capex, equal to approximately 13 full time equivalent staff members.[44]

ETSA Utilities stated the SA Government was proposing a derogation from the NER, to continue the application of chapter 3 of the EDC. ETSA Utilities also stated that while the form of the derogation was uncertain at the time of submitting its revised regulatory proposal, it understood that the derogation would only impact on new and upgraded connections, and even with the derogation in effect, it would still require additional resources under the revised negotiating framework.[45]

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39 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 26.
40 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment B.1.
41 ESCOSA, *Electricity Distribution Code*, December 2005, chapter 3.
42 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 29.
43 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 28.
44 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 28.
45 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 28.

3.3 Submissions

The AER received submissions from the Trans Tasman Energy Group (TTEG) and the South Australian Minister for Energy (SA Energy Minister) on ETSA Utilities' revised negotiating framework.

TTEG

The TTEG supported the draft decision but submitted that there were anomalies in the subsequent revised negotiating framework.[46] It proposed a number of amendments to ETSA Utilities' revised negotiating framework, including:[47]

- the determination of terms and conditions (including price) for negotiated distribution services by ETSA Utilities, particularly those to be offered via an indicative price list
- arrangements for handling of commercial information
- arrangements for fees associated with processing applications
- specification and grouping of negotiated distribution services
- dispute progression
- determining timeframes for applications
- editorial matters.

SA Minister for Energy

The SA Energy Minister submitted that the AER's approach to ETSA Utilities' negotiating framework would result in key consumer protections regarding network connections and charges being removed. Further, he stated the fee of $2750 for any person notifying the AER of an access dispute is a backward step from current practices undertaken in South Australia by ESCOSA.[48]

The SA Energy Minister further stated he will seek approval from the Ministerial Council on Energy (MCE) to have this fee waived for small to medium sized consumers and bring it in line with the *National Gas Law and Regulations* which do not require small customers to pay a fee for notification of a gas access dispute.[49]

3.4 Issues and AER considerations

3.4.1 Negotiated distribution service criteria

The AER notes that ETSA Utilities accepted the draft decision on the NDSC and incorporated these into its negotiating framework.

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46 TTEG, *Submission to the AER in response to ETSA Utilities' revised regulatory proposal*, February 2010, p. 1.
47 TTEG, *Submission to the AER*, February 2010, pp. 1–6.
48 SA Energy Minister, *Submission*, 15 February 2010, p. 2.
49 SA Energy Minister, *Submission*, 15 February 2010, p. 2.

3.4.2 Revised negotiating framework

The AER has considered ETSA Utilities' revised negotiating framework to ensure that it complies with clauses 6.7.5(a) and 6.7.5(c) of the NER. Consistent with the draft decision, ETSA Utilities:

- removed the pricing principles included in the original negotiating framework
- referenced the NDSC as the basis upon which prices/charges are determined
- removed the connections arrangements adapted from chapter 3 of the EDC.[50]

The AER notes TTEG queried how prices for price list services (and all negotiated distribution services) were to be derived. The AER notes that ETSA Utilities has in its 'provisions applicable to all negotiated distribution services' provided that the charges for negotiated distribution services are in compliance with the NDSC as well as ETSA Utilities' cost allocation method. Further, all references to price list services in the revised negotiating framework have been expressed to be indicative only.

The AER does not consider that further amendments are required in relation to the derivation of the terms and conditions, including price for negotiated distribution services, irrespective of the service being included in the indicative price list. However, the AER reiterates its position that all negotiated distribution services are by definition negotiable and their terms and conditions (including price) are to be consistent with the NDSC. While the AER has no objection to ETSA Utilities grouping certain services as 'indicative price list services', in this decision the AER is not providing an ex–ante assessment or approval of the actual prices that may be offered via such a list. The AER will make an assessment of the actual prices in the event that a customer raises a dispute under Part 10 of the NEL and Part L of the NER. One of the key considerations in assessing the terms and conditions (including price) of a disputed service offering will be its compliance with the NDSC.

Finally, the AER notes that ETSA Utilities has tried to address the minimum requirements set out in clause 6.7.5(c) of the NER for all negotiating distribution services, including 'indicative price list services'. However, the AER considers further amendments are required.

NER clause 6.7.5(c)(2) – commercial information provision

ETSA Utilities attempted to address clause 6.7.5(c) of the NER in Part C of its negotiating framework. The 'timetable for indicative price list services' in table 3 seeks to set out that a service application must include commercial information required by ETSA Utilities to enable it to make an offer to the applicant. The AER agrees with TTEG, that the information required must be that which is 'reasonably' required by ETSA Utilities to make an offer.[51] The AER considers that table 3 of ETSA Utilities' negotiating framework should be amended to include this requirement to ensure compliance with clause 6.7.5(c)(2) of the NER.

[50] Chapter 3 of the EDC concerned connections requiring network extension and/or augmentation.
[51] TTEG, *Submission to the AER*, February 2010, p. 4.

NER clause 6.7.5(c)(7) – application processing expenses

ETSA Utilities attempted to address clause 6.7.5(c)(7) of the NER in Part B of its negotiating framework. Section 16 seeks to set out arrangements for payment of fees associated with costs incurred by ETSA Utilities in processing an application for a negotiated distribution service. TTEG submitted that it is unclear whether a further application fee would be applied if an application was resumed following a suspension of negotiations.[52] ETSA Utilities confirmed that an application is not terminated unless notified in accordance with clause 17 of the negotiating framework ('termination of negotiations') and that no new application fee is required after negotiations have been suspended.[53] The AER considers that section 16 of ETSA Utilities negotiating framework should be amended to clarify this matter to ensure compliance with clause 6.7.5(c)(7) of the NER.[54]

NER clause 6.7.5(c)(6) – dispute resolution

ETSA Utilities attempted to address clause 6.7.5(c)(6) of the NER in various sections of its negotiating framework. As submitted by TTEG, to ensure consistency with clause 6.7.5(c)(6) all references to dispute resolution need to provide that disputes will be dealt with in accordance with the relevant provisions of the NEL as well as the NER. The AER considers that clause E of the 'preamble' section of ETSA Utilities negotiating framework should to be amended to this effect to ensure compliance with clause 6.7.5(c)(6) of the NER.

Other issues raised in submissions

TTEG proposed that should a service applicant and a DNSP be involved in a dispute regarding the provision of a negotiated distribution service, the service should still be provided at the DNSP's proposed price while the dispute is being resolved. TTEG was concerned that if ETSA Utilities simply suspended negotiations and this did not occur, then, it might in effect 'force' the service applicant to accept the offering.[55] The AER notes that section 14 of ETSA Utilities' revised negotiating framework sets out a number of situations in which negotiations would be suspended. These relate to situations in which negotiating parties do not comply with the negotiating framework as required under clause 6.7.5(e) of the NER, or situations in which a dispute has been notified to the AER. TTEG's proposal goes beyond the matters set out in section 14 of ETSA Utilities' negotiating framework. The AER considers that TTEG's proposal can be considered either by the negotiating parties when a dispute arises or by the AER in undertaking its dispute resolution responsibilities.

TTEG's submission also highlighted a number of editorial issues concerning ETSA Utilities' revised negotiating framework. These concern cross referencing within the negotiating framework, and clarifying that clause 14.1(b), which refers to the

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52 TTEG, *Submission to the AER*, February 2010, p. 4.
53 ETSA Utilities, *email to the AER – ETSA Utilities revised negotiating framework*, 23 March 2010.
54 ETSA Utilities has advised the AER as to the appropriate wording for this amendments.
55 TTEG, *Submission to the AER*, February 2010, pp. 3–4.

timeframe for the provision of commercial information requested by ETSA Utilities, should have a timeframe of 10 days 'or as otherwise agreed between the parties'.[56]

Further, while not requiring amendment, the following clarifications in regard to specific clauses of ETSA Utilities' revised negotiating framework are noted by the AER in response to TTEG's submission:

- clause 27 allows for an email to be an acceptable form for a notice, consent, information, application or request

- clause 6.4 permits a service applicant to forward commercial information provided by ETSA Utilities on to their professional advisors if these advisors comply with the confidentiality requirements

- clause 21.1(b) allows for negotiating parties by agreement to extend the time period specified in Table 3 of the negotiating framework.

In summary, the AER has assessed ETSA Utilities' revised negotiating framework and the matters raised by TTEG and considers that to ensure consistency with the requirements set out in Part D of the NER, three further amendments are required:

- commercial information provision

- application processing expenses

- dispute resolution.

3.4.3 Customer connections arrangements

The AER notes that in the current regulatory control period ESCOSA is responsible for administering the charging regime for connections requiring network extension, modification or augmentation, through specific provisions in the EDC and its accompanying Guideline 13.[57] While ESCOSA currently administers this regime via a jurisdictional derogation in clause 9.29.2 of the NER, the derogation expires on 1 July 2010. The MCE is currently developing a National Energy Customer Framework (NECF) which will include a national framework for electricity distribution network connection and capital contribution arrangements, but is not anticipated to be introduced by 30 June 2010.[58]

However, as the NECF is some way off implementation, the AER understands the SA Government is concerned that if chapter 3 of the EDC ceased operation, the AER would regulate distribution network connections solely in accordance with provisions of the NER (in particular chapters 5 and 6). The SA Government considered that the

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[56] The AER drew these editorial matters to the attention of ETSA Utilities who agreed that the corrections should be made. These corrections are set out in section 3.5 of this decision. ETSA Utilities, *email to the AER – ETSA Utilities revised negotiating framework*, 23 March 2010.

[57] Electricity industry guideline 13 elaborates on the application of specific provisions of chapter 3 of the EDC.

[58] MCE, *Communique*, 20 April 2010, accessible at: www.ret.gov.au/documents/mce/quicklinks/bulletins.html.

NER currently lacks a number of significant regulatory requirements that are contained in the EDC to protect consumer interests. In particular, the EDC contains specific provisions for calculating customer contributions for establishing new or modifying existing connections that require network extensions or augmentations.

ETSA Utilities sought to replicate the provisions of chapter 3 of the EDC in its proposed negotiating framework. The draft decision did not approve these inclusions as they were not consistent with the purpose of the negotiating framework set out in clause 6.7.5(a) of the NER.

Since publication of the draft decision and submission of ETSA Utilities revised regulatory proposal, the SA Government sought a rule change to continue the operation of the current connections arrangements. The rule change proposal provides that:

- the charging regime set out in sections 3.3 to 3.11 of chapter 3 of the EDC and the accompanying Guideline 13 would be extended via a derogation
- the derogation would be for the period of 1 July 2010 to 30 June 2015, or until such a time as the NECF is operational in SA
- responsibility for administering the provisions in these sections would be transferred from ESCOSA to the AER
- the AER would have a level of discretion in carrying out these provisions similar to that of ESCOSA, with the exception of the unit cost of augmentation 'f' variable which would be fixed at $135 and indexed
- the transferred provisions of chapter 3 of the EDC and guideline 13 would take precedence over any potentially conflicting provisions in the NDSC or negotiating framework.

The derogation has been proposed as a non–controversial rule change in accordance with section 96 of the NEL and is therefore being assessed via the expedited process set out in the NEL.[59] At the time of the AER's decision, the rule change is yet to be made by the AEMC. Should it be implemented, the AER notes that negotiated distribution services would continue to be provided in accordance with the NDSC, negotiating framework and other aspects of the NER. However, services associated with connections requiring network extension/augmentation would be provided subject to the provisions in chapter 3 of the EDC and these provisions would be implemented by the AER. The AER considers that the EDC regime for such connection services, if continued via the derogation, would provide certainty for businesses and customers wishing to connect to the electricity distribution network as the existing arrangement would continue until the NECF is implemented.

[59] AEMC, *Consultation on SA jurisdictional derogation (connections charging)*, 18 March 2010, accessible at: http://www.aemc.gov.au/News/Whats-New/Consultation-on-SA-Jurisdictional-Derogation-Connections-Charging.html.

3.4.4 Negotiation capex proposal

ETSA Utilities proposed an additional $6 million in capex for the next regulatory control period to accommodate a need for increased resources to negotiate distribution services under the negotiating framework arrangement. In support of its proposal, it stated that in the current regulatory control period prices are either fixed through its price list or determined in accordance with chapter 3 of the EDC.

The AER notes that ETSA Utilities' proposed additional capex requirements related to negotiated distribution services. In order for capex to be included in the AER's building block determination such capex must relate to standard control services. ETSA Utilities' proposed additional capex does not relate to standard control services and the NER does not require the AER to approve regulated revenues for negotiated distribution services. The proposed $6 million has been removed from ETSA Utilities forecast capex.[60]

3.5 AER conclusion

Negotiated distribution service criteria

The AER considers that the NDSC are consistent and give effect to the negotiated distribution service principles in clause 6.7.1 of the NER. The NDSC applying to ETSA Utilities for the next regulatory control period are unchanged from the draft decision and are set out in appendix C of this decision.

Negotiating framework

In accordance with clause 6.12.3(g) of the NER, the AER does not approve the revised negotiating framework proposed by ETSA Utilities as it does not comply with the requirements of Part D of the NER.

Consistent with clause 6.12.3(h)(2) of the NER, the AER considers that further amendments to ETSA Utilities' negotiating framework are necessary to enable it to be approved in accordance with the NER. The required amendments are as follows:

1. amendment to table 3 – timetable for indicative price list services to capture clause 6.7.5(c)(2) of the NER, by providing that commercial information is to be as 'reasonably' required by ETSA Utilities to enable it to make an offer to the applicant.
2. amendment to section 16 – payment of ETSA Utilities' application fee. To address clause 6.7.5(c)(7) of the NER, section 16 needs to adequately clarify the arrangements for payment of application processing expenses. A footnote needs to be added to clarify that no new application fee is required after negotiations have been suspended.
3. amendment to clause E – Preamble to address clause 6.7.5(c)(6) by noting that disputes are to be dealt with in accordance with the relevant dispute provisions of the NEL as well as the NER.

[60] The AER's decision on this proposal is set out in section 7.4.5 of this decision.

The AER has amended ETSA Utilities revised negotiating framework in accordance with these requirements and the amended negotiating framework is at appendix D of this decision.

Further, while not specifically required under the NER, the AER notes that ETSA Utilities has agreed to undertake a number of editorial amendments to its revised negotiating framework arising from matters identified by TTEG's submission.[61] These include the following:

- point G in the Preamble section should reference figure 1
- clause 3.4 should crossreference clause 20
- table 2 – Event C should crossreference clauses 13 and 16
- clause 18.1(d) should crossreference clause 24
- table 3 – Event C should crossreference clauses 23 and 25
- clause 14.1(b) – which refers to the timeframe for the provision of commercial information requested by ETSA Utilities – should have a timeframe of 10 days 'or as otherwise agreed between the parties'.

3.6 AER decision

In accordance with clause 6.12.1(15) of the NER, the AER does not approve ETSA Utilities' revised negotiating framework and the amended negotiating framework set out in appendix D to this decision will apply to ETSA Utilities for the next regulatory control period.

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

[61] ETSA Utilities, *Email to the AER – ETSA Utilities revised negotiating framework*, 23 March 2010.

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 classified 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 ETSA Utilities during the next regulatory control period.[62] For ETSA Utilities' standard control services this mechanism is a weighted average price cap (WAPC). This chapter discusses how this mechanism will be applied and sets out how the AER will determine compliance with the mechanism during the next regulatory control period.

4.1 AER draft decision

The AER accepted ETSA Utilities' proposal that a WAPC be applied to its standard control services for the next regulatory control period. The AER did not accept ETSA Utilities' proposal to forecast an amount for transitional factors as a building block component rather than an annual adjustment.[63]

The AER accepted ETSA Utilities' proposal to recover transmission use of system (TUOS) costs in a manner consistent with the approach used by the NSW DNSPs. The AER did not accept ETSA Utilities' proposal for a within period interest charge on TUOS payments.[64]

No submissions were received concerning the operation of the control mechanisms for ETSA Utilities' standard control services.

4.2 Revised regulatory proposal

ETSA Utilities proposed three changes from the control mechanism set out in the draft decision:[65]

- the retention of the $(1+D_t)$ term in the WAPC and side constraint formulas, to accommodate any forgone revenue adjustment under Part B of the demand management incentive scheme (DMIS)
- the tariff classes applicable to the side constraint formula
- a mechanism to recover working capital, to fund TUOS payments.

4.2.1 Retention of the $(1+D_t)$ term

ETSA Utilities did not agree with the removal of the $(1+D_t)$ term from the WAPC and side constraints formulas in the draft decision. ETSA Utilities argued that, while the

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62 AER, *Final decision, Framework and approach paper, ETSA Utilities 2010–15*, November 2008.
63 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 46.
64 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 49.
65 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 33.

demand management innovation allowance (DMIA) has been included as an adjustment to ETSA Utilities' opex, any forgone revenue adjustment under Part B of the DMIS needs to be accommodated using this term.[66]

ETSA Utilities stated that it:[67]

> can see no reason that the $(1+D_t)$ term should not be retained and applied to the approved foregone [sic] revenue adjustment that occurs over the period. If such an adjustment is not made in the following year in which it occurs, it is a further disincentive to undertake demand management projects, especially early in the regulatory period. This is consistent with the AER's express intention in the Framework and approach paper that recovery of any revenue foregone [sic] as a result of the implementation of demand management projects or programs approved under the DMIS in Part A takes place within the regulatory control period in which the scheme applies.

In addition, ETSA Utilities proposed that the recognition of forgone revenue should not be limited to demand management projects under the DMIS, but should be extended to forgone revenue associated with any demand management project, which is undertaken during the next regulatory control period. ETSA Utilities stated that recognition of forgone revenue associated with all demand management projects is essential to overcome the inherent barrier against such projects.[68]

4.2.2 Tariff classes used in the assessment of side constraints

ETSA Utilities accepted the draft decision that 'variable' metering services should not be classified as standard control services. As a consequence, ETSA Utilities revised the tariff classes nominated in its regulatory proposal. The revised tariff classes proposed by ETSA Utilities for assessing compliance with the side constraints are:[69]

- major business
- high voltage business
- low voltage business (including unmetered supplies)
- residential.

4.2.3 Recovery of TUOS payments

ETSA Utilities did not agree with the draft decision to not provide a within period interest charge on TUOS payments. ETSA Utilities argued that it is obliged to make payments on a monthly basis to ElectraNet and others in respect of TUOS and avoided TUOS charges before recouping these funds from customers over the ensuing four months. ETSA Utilities stated there was approximately 28 days between the payment and receipt of these amounts.[70]

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66 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 38.
67 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 38.
68 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 38.
69 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 39.
70 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 37.

ETSA Utilities stated that it is obliged to maintain working capital to finance the early payment of TUOS charges on a continuous basis. It asserted that 'the necessity of working capital for business operations is recognised in other aspects of the regulatory revenue modelling'. ETSA Utilities stated that the draft decision to not permit a working capital allowance for the within period financing of TUOS payments is inconsistent with the following:[71]

- a universally accepted economic principle that the time value of money should be recognised;
- the objective of the National Electricity Law, which is to 'encourage efficient investment in … electricity services for the long-term interests of consumers'. This involuntary investment generates a negative return, since its value decreases with the passage of time between payment and receipt, and thus is not an efficient investment;
- other provisions made by the AER in the PTRM concerning the time value of money, for example in the recognition of capital expenditure occurring throughout a financial year, in accordance with clause 6.4.2 of the Rules;
- the provision proposed to be made by the AER concerning the treatment of interest on opening balance of the TUoS overs and unders account; and
- the provisions of the 2005–2010 electricity distribution price determination (EDPD), where this financing cost was recognised by ESCoSA and formed part of the ETSA Utilities' revenue allowance.

ETSA Utilities noted that no alternative provision is made elsewhere in the AER's modelling for the working capital to cover TUOS financing costs. ETSA Utilities reiterated its proposal that the within period financing of TUOS payments should be factored into the TUOS under and over recovery calculation.[72]

4.3 Issues and AER considerations

4.3.1 Retention of the $(1+D_t)$ term

In the draft decision, the AER dropped the $(1+D_t)$ term from the WAPC and side constraints formulae on the basis that this term will not be needed during the next regulatory control period. However, ETSA Utilities proposed to retain the $(1+D_t)$ term, arguing that according to the framework and approach, forgone revenue adjustments were intended to be made during the next regulatory control period.[73]

The AER notes during the development of the DMIS, its intention was always that the assessment of whether ETSA Utilities had suffered any forgone revenue due to a demand management initiative would be undertaken on an annual basis. However, the

[71] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 37.
[72] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 37.
[73] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 38.

compensation for any such forgone revenues was to be made in the 2015–20 regulatory control period. In this regard, the DMIS clearly stated:[74]

> Approved forgone revenue will be returned to the DNSP in a single adjustment in the second regulatory year of the subsequent regulatory control period, at the same time as any adjustment under part A.

The AER notes that no change to this position was discussed in the framework and approach referred to by ETSA Utilities, although the AER's position in that paper may not have been quite so clearly stated.[75]

As noted in the draft decision, the AER recognised that the $(1+D_t)$ term would be needed for the 2015–20 regulatory control period.[76] Accordingly, the AER has reinstated the $(1+D_t)$ term in the WAPC and side constraint formulae but, based on the DMIS, will treat the D_t term as zero for the next regulatory control period.

The AER's response regarding the scope of the forgone revenue adjustment is discussed in chapter 14 of this decision.

4.3.2 The ESCOSA's demand management allowance

In the draft decision, the AER decided that there would be an adjustment in relation to the demand management allowance approved by ESCOSA for the current regulatory control period. That is, any unspent funds would be returned to customers as part of the distribution determination.[77] ETSA Utilities accepted the draft decision but not the AER's rationale, suggesting that there is no legal basis upon which an adjustment could be made. This view was also shared by ESCOSA.[78]

The AER understands that ESCOSA has now signalled its intent to amend ETSA Utilities' distribution licence and impose an obligation upon it to undertake a specific demand management project to account for any unspent funds.[79] The scope and timing of the project, believed to be related to advanced metering systems with direct load control capabilities, will be agreed between ESCOSA and ETSA Utilities. The demand management project will be assessed and approved by ESCOSA and has no bearing upon the AER's distribution determination for ETSA Utilities. Reference to an adjustment in relation to ESCOSA's demand management allowance has therefore been removed from the definition of the $EDPD_t$ term in the WAPC and side constraints formulae.

4.3.3 Tariff classes used in the assessment of side constraints

The AER accepts ETSA Utilities' proposed tariff classes as set out in its revised regulatory proposal. The classification of metering services, which lead to the revision of tariff classes, is discussed in chapter 2 of this decision.

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74 AER, *Demand Management Incentive Scheme: Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008, p. 11.
75 AER, *Final decision, Framework and approach paper: ETSA Utilities 2010–15*, November 2008, pp. 95–96.
76 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 52.
77 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 51.
78 ESCOSA, email to the AER, 20 January 2010.
79 ESCOSA, email to the AER, 20 January 2010.

4.3.4 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.[80] 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 to the prices for 2011–12, when these prices will be compared against the prices for 2010–11.

4.3.5 Recovery of TUOS payments

ETSA Utilities reiterated its proposal for an interest charge on TUOS payments made to ElectraNet due to a perceived cash flow disadvantage in the timing of recovery of TUOS payments. ETSA Utilities provided information to show when a typical month's TUOS is paid to the TNSP and when this amount is recovered from customers.[81] It shows that for any single month there will be a delay between receipt and payment of TUOS charges. The AER does not dispute this observation for a single month. However, the AER considers that ETSA Utilities has failed to consider the overlapping effect of TUOS receipts and payments from all months over time.

The AER's position in the draft decision was that any cash flow disadvantage ETSA Utilities may have faced would have been 'a one-off effect' which would have occurred when ETSA Utilities first began operating in the NEM.[82] The AER considers that this position is still valid and the example in table 4.1 demonstrates this one-off effect.

Table 4.1: Example of cash flow timing of TUOS payments and receipts ($, 000)

Month	1	2	3	4	5
Payments to transmission service provider	1000	1005	990	1000	995
Receipts from customers	0	1000	1005	990	1000
Difference in cash flow for the month	–1000	–5	15	–10	5

In the example, it has been assumed that TUOS is paid in full by the DNSP in the month the transmission services are provided, while payment from customers is received in full by the DNSP one month later. Consistent with ETSA Utilities' argument, table 4.1 illustrates that the DNSP could suffer a significant cash flow

80 AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, pp. 63–64; and AER, *Final decision, Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April 2009, pp. 19–20.

81 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment C.1, figure 2.

82 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 52.

disadvantage in month one (this is the one-off effect referred to by the AER in its draft decision).

After this initial month, however, it is not apparent that the DNSP will face a bias towards further negative cash flow outcomes due to the timing of TUOS payments and receipts. Indeed, some months could be cash flow positive (as illustrated in table 4.1 for months three and five). ETSA Utilities provided no evidence to suggest a particular trend in this regard. The cash flow effects for these subsequent months are also likely to be relatively insignificant compared to that implied by looking simply at the first month (that is, month one) as ETSA Utilities has done. In addition, the AER notes that the effect observed in month one does not suddenly resurface when the business reaches month 13 (that is, next year) as the DNSP continues to receive TUOS payments from customer for services provided in the previous year.

The AER considers that its position in the draft decision is not inconsistent with the interest charge on the opening balance of the TUOS unders and overs account, or ‘a universally accepted economic principle that the time value of money should be recognised’, as ETSA Utilities asserted. The interest charged on the opening balance of the TUOS unders and over account is a year–on–year adjustment for the time value of money, whereas ETSA Utilities’ proposal is for a general working capital allowance on TUOS payments during the year, regardless of the particular timing of actual cash flows.

The AER notes that ESCOSA’s approach to TUOS under/over recoveries did not account for the time value of money. ETSA Utilities’ claim that financing costs were recognised by ESCOSA appears to be in relation to a general working capital allowance, rather than a specific allowance in relation to TUOS payments. ESCOSA’s working capital allowance reflected the particular building block approach it adopted at the time, rather than the building block approach under the NER.

The AER does not agree with ETSA Utilities that its position in the draft decision is inconsistent with the objectives of the NEL. The AER considers that there is no systematic cash flow disadvantage currently faced by ETSA Utilities in relation to the timing of TUOS payments and receipts.

Based on the above considerations, the AER rejects ETSA Utilities’ proposal for an additional interest charge on its TUOS payments for cash flow timing issues.

4.4 AER conclusion

As part of its pricing proposal, ETSA Utilities must submit to the AER proposed tariffs and charging parameters which correspond to the price terms contained in the WAPC and side constraint equations set out below. Each of the relevant percentage factors (for example, CPI_t) must be rounded to two decimal places before being applied in the WAPC and side constraints formulas.

4.4.1 Weighted average price cap

The WAPC formula to apply to ETSA Utilities for the next regulatory control period is:

$$(1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+D_t)\times(1+U_t)\times(1+EDPD_t)\pm(passthrough_t)\geq\frac{\sum_{i=1}^{n}\sum_{j=1}^{m}p_t^{ij}\times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m}p_{t-1}^{ij}\times q_{t-2}^{ij}}$$

Where:

ETSA Utilities has ‘n’ distribution tariffs, which each have up to ‘m’ distribution tariff components, and where:

regulatory year t is the regulatory year in respect of which the calculation is being made

regulatory year t–1 is the regulatory year immediately preceding regulatory year t

regulatory year t–2 is the regulatory year immediately preceding regulatory year t–1

p_t^{ij} is the proposed distribution tariff for component j of distribution tariff i in regulatory year t

p_{t-1}^{ij} is the distribution tariff being charged in regulatory year t–1 for component j of distribution tariff i

q_{t-2}^{ij} is the quantity of component j of distribution tariff i that was delivered in regulatory year t–2

X_t is the allowed real change in average prices from year t–1 to year t of the regulatory control period as determined by the AER

S_t is the service target performance incentive scheme factor to be applied in regulatory year t

D_t is the demand management incentive scheme factor to be applied in regulatory year t, which is set equal to zero for each year of the next regulatory control period

U_t is the undergrounding factor to be applied in regulatory year t

$EDPD_t$ is the EDPD transition factor for regulatory year t. It is a carryover of adjustments made in the 2005–2010 EDPD comprising the previous K, Q, PU and SI factor adjustments

$passthrough_t$ is the change in approved pass through amounts, expressed in percentage form, with respect to regulatory year t as compared to regulatory year t–1, as determined by the AER

CPI_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 regulatory year t–2 to March in regulatory year t–1.

4.4.2 Side constraints

The side constraints formula to apply to ETSA Utilities for the next regulatory control period is:

$$(1+CPI_t)\times(1-X_t)\times(1+S_t)\times(1+D_t)\times(1+U_t)\times(1+EDPD_t)\times(1+2\%)\pm(passthrough_t)\geq\frac{\sum_{j=1}^{m} d_t^j \times q_{t-2}^j}{\sum_{j=1}^{m} d_{t-1}^j \times q_{t-2}^j}$$

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-2}^j is the audited quantity of component j of the tariff class that was charged by the DNSP in year t–2

X_t is the allowed real change in average prices from year t–1 to year t of the regulatory control period as determined by the AER. If X>0, then X will be set equal to zero for the purposes of the side constraint formula

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year t

D_t is the Demand Management Incentive Scheme factor to be applied in regulatory year t, which is set equal to zero for each year of the next regulatory control period

U_t is the undergrounding factor to be applied in regulatory year t

$EDPD_t$ is the EDPD transition factor for regulatory year t. It is a carryover of adjustments made in the 2005–2010 EDPD comprising the previous K, Q, PU and SI factor adjustments

$passthrough_t$ is the change in approved pass through amounts, expressed in percentage form, with respect to regulatory year t as compared to regulatory year t–1, as determined by the AER

CPI_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.

In addition, ETSA Utilities can not raise the fixed supply charge for small customers by more than $10 per annum during the next regulatory control period.

4.4.3 Ring fencing and compliance monitoring

Clause 9.29.7 of the NER states that on the AER's assumption of responsibility for the economic regulation of distribution services in South Australia, the guidelines

Operational Ring–fencing Requirements for the SA Electricity Supply Industry: Electricity Industry Guideline No. 9, dated June 2003 will be taken to be distribution ring–fencing guidelines issued by the AER under clause 6.17 of the NER (ring–fencing guideline). The ring–fencing guideline will therefore be regarded as the AER's ring fencing guideline for South Australia.

The ring–fencing guideline sets out specific requirements in regard to separation of licensed entities, definition of related businesses, compliance procedures, information flows to related businesses, ring fencing waivers and procedures for revising the guidelines. Cost allocation methods prepared by ETSA Utilities that are to be applied in the next regulatory control period were approved by the AER in February 2009.[83]

To the extent that ESCOSA's reporting guideline does 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. Appendix L should be read in conjunction with ESCOSA's *Electricity Industry Guideline No. 4, Compliance Systems and Reporting*.

4.5 AER decision

In accordance with clause 6.12.1(11) of the NER, the control mechanism for standard control services provided by ETSA Utilities is a weighted average price cap. The applicable weighted average price cap and side constraint formulae are set out in section 4.4 of this decision.

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

In accordance with clause 6.12.1(19) of the NER, ETSA Utilities 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 F of this decision.

83 ETSA Utilities, *Cost allocation method*, September 2009.

5 Opening regulatory asset base

This chapter sets out the method used by the AER to determine the closing regulatory asset base (RAB) for ETSA Utilities 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

The AER did not approve the inclusion of ETSA Utilities' proposed easement revaluation and the reinstatement of capital contributions removed by ESCOSA in the roll forward of the opening RAB.[84]

Metering assets associated with alternative control services were also removed from ETSA Utilities' RAB for standard control services.[85]

The RAB roll forward calculations for ETSA Utilities are set out in table 5.1 and provided for an opening RAB of $2768 million for standard control services for the next regulatory control period (as at 1 July 2010).

Table 5.1: AER draft conclusion on ETSA Utilities' opening RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10
Opening RAB	2501.8	2590.2	2625.7	2698.2	2770.1
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	149.4	122.5	119.9	176.5	193.2
Regulatory depreciation (adjusted for actual CPI)	–61.0	–87.1	–47.4	–104.6	–111.9
Closing RAB	2590.2	2625.7	2698.2	2770.1	2851.4
Difference between actual and forecast capex for 2004–05					–0.3
Return on difference					–0.2
Removal of metering assets					–82.6
Opening RAB at 1 July 2010					2768.4

Source: AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 73.

No submissions were received on the opening RAB for ETSA Utilities.

84 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 69–70.
85 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 70.

5.2 Revised regulatory proposal

ETSA Utilities proposed a revised opening RAB of $2903.0 million as at 1 July 2010, $134.7 million greater than allowed by the AER in the draft decision.

ETSA Utilities updated the capex figures for 2008–09 and 2009–10 in its roll forward model (RFM). It also rejected the AER's adjustments to its RAB in respect of:[86]

- valuation of easements
- ESCOSA's treatment of certain capital contributions.

5.2.1 Revised capex

In its revised RFM, ETSA Utilities included updated capex figures for 2008–09 to account for actual outcomes.

5.2.2 Valuation of easements

ETSA Utilities stated that the AER's grounds for its draft decision in respect of the valuation of easements have been affected by three fundamental errors:[87]

> - a failure to acknowledge and implement the combined effect of clause 7.3(b)(iv) of the [Electricity Pricing Order] EPO and sections 18(4) and 18(8) of the *National Electricity (South Australia) Act 1996* and their primacy over the NER;
> - giving undue weight to the decision of ESCoSA in the 2005–2010 Price Determination for distribution services in respect of clause 7.2(e)(iv) of the EPO, and insufficient weight to the:
>   - differences in the AER and Australian Competition Tribunal decisions concerning the valuation of ElectraNet's transmission network easements that occurred after ESCoSA's 2005–2010 Price Determination; and
>   - the differences between the Submission for Adjustment to the Opening RAB made to the AER for the opening RAB for 2010 and the application made to ESCoSA for the opening RAB in 2005 concerning the valuation of the distribution network easements,
> - a failure to recognise:
>   - that the $6 million allowance for easements specified in Schedule 9 of the EPO was not, and was expressed not to be, a valuation of distribution network easements, but rather was an amount determined in lieu of a valuation as an unavoidable direct consequence of an inability to do a valuation at that time; and
>   - that the EPO committed to a consideration of a proper valuation once the data set necessary for such a valuation was available, …

[86] ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 181–184.
[87] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 181.

As a result of these errors, ETSA Utilities considered the AER failed to discharge its functions under clause 7.3(b)(iv) and sections 18(4) and 18(8) of the *National Electricity (South Australia) Act 1996*.[88]

ETSA Utilities proposed an increase to the opening RAB as at 1 July 2005 with respect to easements of $116.2 million (being $123.5 million less the original allowance of $6 million indexed to 1 July 2005).[89]

5.2.3 ESCOSA's treatment of capital contributions

ETSA Utilities disagreed with the draft decision regarding the adjustment made by ESCOSA to remove certain customer contributions from ETSA Utilities fixed asset base as at 1 July 1999. ETSA Utilities remained of the view that there was an error made by ESCOSA regarding this matter. ETSA Utilities argued:[90]

> [c]lause 7.2(e)(iii) of the EPO cannot support the position taken by ESCOSA on its own terms. The reason is that clause 7.2(e)(iii) **only** has application to an augmentation or extension, which would otherwise be 'an addition' to the fixed asset base under clause 7.2(e)(i). The only augmentations or extensions which can be 'an addition' to the fixed asset base under clause 7.2(e)(i) are additions '…**since** the Commencement Date'.

Accordingly, ETSA Utilities stated there was no basis for the deduction made by ESCOSA for the 2005 price determination in clause 7.2 of the EPO and considered it was an error on the part of ESCOSA. To give effect to the EPO, ETSA Utilities considered that the AER now must discharge the same function as should have been discharged by ESCOSA by virtue of clause 7.3(b)(i) of the EPO.[91]

ETSA Utilities disagreed with the draft decision that an inability to rely upon adjustments previously made by ESCOSA would require the AER to reconsider all previous adjustments made by ESCOSA. ETSA Utilities argued that the AER can rely upon a presumption of regularity in respect of the previous actions of ESCOSA. Only where there are reasonable grounds to believe that ESCOSA's functions may have miscarried, is that presumption rebutted by that evidence. ETSA Utilities considered that there is more than sufficient evidence to rebut the presumption of regularity on the part of the discharge by ESCOSA of its functions in this case.[92]

In conclusion, ETSA Utilities stated that:[93]

> in any event, the AER must now discharge the same function under clause 7.3 of the EPO (which overrides the NER on this matter), and it is important that the error is corrected, rather than repeated.

5.2.4 Adjustments made by the AER

Notwithstanding the concerns raised by ETSA Utilities regarding the valuation of easements and ESCOSA's treatment of certain capital contributions, ETSA Utilities

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88 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 181.
89 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 184.
90 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 184.
91 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 184.
92 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 184.
93 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 184.

also raised concerns about the size of the adjustments made by the AER in respect of these matters in the draft decision. ETSA Utilities observed that in adjusting the RFM to reflect its draft decision, the AER deducted ETSA Utilities' proposed adjustments of $116.2 million and $16.3 million respectively from the opening RAB value in the RFM. However, ETSA Utilities claimed that the values for the adjustments made by the AER are denominated in June 2005 dollars, whereas the opening RAB value in the RFM is in June 2004 dollars. ETSA Utilities submitted that:[94]

> any adjustments made by the AER should have been stated in June 2004 dollars, which amounts to $113.5 million and $15.953 million respectively. When these nominal values are inputted into the RFM:
>
> - the RAB value at 30 June 2005 (before deducting metering) increased by $3.1 million from the AER's Draft Determination value of $2,501.8 million (referred to in table 5.4) to $2,504.9 million; and
>
> - the RAB value at 30 June 2010 (before deducting metering) increased by $3.5 million from the AER's Draft Determination value of $2,850.9 million to $2,854.4 million.

5.2.5 Removal of metering assets

In its revised regulatory proposal, ETSA Utilities accepted the draft decision to reclassify certain metering services as alternative control services. ETSA Utilities proposed an $80.5 million reduction to its opening RAB as at 1 July 2010 to account for the value of metering assets now used for alternative control services.[95]

5.3 Issues and AER considerations

5.3.1 Revised capex

The AER has accepted ETSA Utilities revised capex for 2008–09. This revision reduced ETSA Utilities' opening RAB as at 1 July 2010 by approximately $3 million compared to the draft decision.

5.3.2 Value of easements

The AER does not intend to reproduce its analysis of the draft decision here; rather the AER will address what ETSA Utilities considered to be 'three fundamental errors' in the draft decision regarding this matter.

A failure[by the AER] to acknowledge and implement the combined effect of clause 7.3(b)(iv) of the EPO and sections 18(4) and 18(8) of the National Electricity (South Australia) Act 1996 and their primacy over the NER.

The AER confirms the draft decision that 'it may have to give regard to clause 7.3 of the EPO and review the value of ETSA Utilities' easements'.[96] The AER remains of the view that it has discretion in this matter.

In determining a DNSP's opening RAB, the AER is to consider the requirements of schedule 6.2 of the NER. Schedule 6.2 includes an opening RAB value of

[94] ETSA Utilities. *Revised regulatory proposal*, January 2010, p. 181.
[95] ETSA Utilities. *Revised regulatory proposal*, January 2010, p. 180.
[96] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 63.

$2466 million for ETSA Utilities. Given this amount accords with the value determined by ESCOSA (and includes the value of easements determined by ESCOSA),[97] it suggests that policy makers had confidence in this valuation. Policy makers also clearly gave consideration to reasons why this value may require amendment and included specific clauses to allow modifications to the values set in Schedule 6.2 of the NER. No clauses were added to schedule 6.2 in respect of the value of ETSA Utilities' easements.[98] This omission suggests that the policy makers did not consider these values to be in dispute and that they wished to provide certainty for the DNSPs and consumers regarding the value of ETSA Utilities' opening RAB.

Nonetheless, in the draft decision, the AER did consider the value of ETSA Utilities' easements under clause 7.3(b)(iv) of the EPO on the presumption that this clause combined with the effect of sections 18(4) and 18(8) of the *National Electricity (South Australia) Act 1996* did have 'primacy' over schedule 6.2 of the NER.

[The AER g]iving undue weight to the decision of ESCoSA in the 2005–2010 Price Determination for distribution services in respect of clause 7.2(e)(iv) of the EPO, and insufficient weight to the:

– ***differences in the AER and Australian Competition Tribunal decisions concerning the valuation of ElectraNet's transmission network easements that occurred after ESCoSA's 2005–2010 Price Determination; and***

– ***the differences between the Submission for Adjustment to the Opening RAB made to the AER for the opening RAB for 2010 and the application made to ESCoSA for the opening RAB in 2005 concerning the valuation of the distribution network easements***

In the draft decision, the AER set out a number of prima facie reasons why it considered it appropriate to review ETSA Utilities easements on the basis of the analysis performed by ESCOSA, in particular:[99]

- ESCOSA was the previous regulator of ETSA Utilities and was familiar with the legislation (that is, the EPO and national electricity code) that established the regulatory arrangements for ETSA Utilities

- ESCOSA gave consideration to the value of ETSA Utilities' easements as part of its 2005 price determination[100]

- ESCOSA reconsidered the value of ETSA Utilities easements as part of a review of its 2005 price determination[101]

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97 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005, table 9.5, p. 124.

98 Nor where any transitional clauses, such as clause 11.6.13(b) concerning ElectraNet's easements, created in respect of ETSA Utilities' easements.

99 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 63–64.

100 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005.

101 ESCOSA, *2005–2010 Electricity Distribution Price Determination, An application by ETSA Utilities for a review pursuant to section 31 of the Essential Services Commission Act 2002, Decision and Reason for Decision*, May 2005.

- as part of its 2005 price determination and subsequent review, ESCOSA consulted with the South Australian Treasurer as to any representations made by the South Australian government concerning the valuation of easements as of part of the government's sale process of ETSA Utilities. This information includes confidential material[102]

- under section 7A(4)(a)(i) of the NEL, the AER should have regard to the RAB contained in any previous distribution determination, which, in this case, is ESCOSA's 2005 price determination.

In its draft decision, the AER reviewed ESCOSA's assessment of easements for both the 2005 price determination and subsequent review and considered ESCOSA's assessment to be consistent with the requirements of the EPO and the national electricity code. The AER was not convinced by ETSA Utilities' argument that circumstances since the 2005 price determination and subsequent review had changed in such a way as to render this assessment invalid.[103]

Regarding the Tribunal's decision on ElectraNet's easements, the AER remains of the view (expressed in the draft decision) that a revaluation was considered appropriate in ElectraNet's circumstances because of representations made to the bidders for ElectraNet. ETSA Utilities noted 'representations were made by the South Australian Government to bidders for the ElectraNet business … those representations were the basis for the creation of clause 11.6.13(b) of the NER'. The AER notes that no similar clause in the NER exists in relation to ETSA Utilities' easements. This omission suggests policy makers considered the circumstances of ElectraNet and ETSA Utilities were not identical. Given these different circumstances, the AER considers that ETSA Utilities' concern over 'regulatory consistency' has no basis.[104]

ETSA Utilities argued that 'the position established by clause 11.6.13(b) of the NER is replicated (at least) by the operation of clause 7.3(b)(iv) and Section 18(4) and 18(8) of the *National Electricity (South Australia) Act 1996*'.[105] The AER accepts this is true insofar as the AER is *permitted* to adjust the asset base. Nothing in any of those provisions, however, *obliges* the AER to make any adjustments to the asset base.

ETSA Utilities asserted that 'the AER did not acknowledge the substantial direct evidence as to the existence of representations to bidders by the South Australian Government'.[106] The AER rejects this assertion. The AER reviewed the evidence of such representations provided by ETSA Utilities both in its submissions to ESCOSA and its regulatory proposal to the AER. The AER is unconvinced that the additional information (which includes statutory declarations from staff of ETSA Utilities and the bidders for ETSA Utilities) proves such representations were made by the South Australian Government.

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[102] In preparing its draft decision, the AER reviewed a confidential version of the ESCOSA's review of its 2005 price determination.
[103] AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 64–67.
[104] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 68.
[105] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 183.
[106] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 183.

The AER does not accept that it failed to take into account the differences between ETSA Utilities' submission to the AER and its application to ESCOSA concerning the valuation of its easements. Nor does the AER accept that these differences warrant any different conclusion to that reached by ESCOSA concerning the value of ETSA Utilities' easements. Besides the ElectraNet decision (discussed above), one of the key differences ETSA Utilities highlighted is that it is no longer claiming easements should be valued using a deprival value, rather it proposed the use of an indexed historic cost value. The AER remains of the view that the conclusion reached by ESCOSA on the appropriate value of ETSA Utilities' easements was not dependant on any particular valuation approach. Therefore, any change of valuation approach is not relevant to the position reached by the AER. For the same reasons, the statutory declaration of Mr Steven (of ETSA Utilities) that the $6 millions attributed by ESCOSA to ETSA Utilities easements was not a historic cost valuation, despite this value being labelled an 'at cost' valuation in the past, is not relevant to the position reached by the AER.[107]

Accordingly, the AER has not considered in depth the 'additional research undertaken between 2007 and 2009' by ETSA Utilities to develop what ETSA Utilities considers to be an indexed historic cost value of its easements. The AER has not assessed what an indexed historic cost of ETSA Utilities easements may be because it considers the value of the easements has already been appropriately determined by ESCOSA.

A failure [by the AER] to recognise:

- ***that the $6 million allowance for easements specified in Schedule 9 of the EPO was not, and was expressed not to be, a valuation of distribution network easements, but rather was an amount determined in lieu of a valuation as an unavoidable direct consequence of an inability to do a valuation at that time; and***

- ***that the EPO committed to a consideration of a proper valuation once the data set necessary for such a valuation was available***

The AER does not consider it relevant whether the $6 million for easements specified in schedule 9 of the EPO was a 'valuation' of ETSA Utilities' easements or determined on some other basis. The AER remains of the view set out in the draft decision:[108]

> for the purposes of clause 7.2(e)(iv) of the EPO and under clause 6.10.3(e)(5)(ii) of the NEC, ESCOSA had the option to revalue ETSA Utilities' easements or to set a value for those easements consistent with the value set in the initial RAB. ESCOSA chose the later approach, which used the value of easements set by the South Australian government in the price control scheme of the EPO at the time.

Given these circumstances, the AER considers it reasonable for it to rely on the $6 million value attributed by ESCOSA to ETSA Utilities' easements.

The AER also does not accept ETSA Utilities' assertion that the EPO committed the regulator 'to a consideration of a proper valuation once the data set necessary for such

[107] Stevens, Robert, *Statutory Declaration*, 16 April 2005, p. 4.
[108] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 67.

a valuation was available'. This misstates clause 7.3(b)(iv) of the EPO. That clause merely directs that the AER should give consideration to assets not included in the asset schedule, including easements used. There is no mention of a revaluation. The AER also notes the South Australian Treasurer's statement contained in ESCOSA's review of its 2005 price determination:[109]

> Had the Government had an explicit policy of revaluing the easements using a deprival methodology, and sought to gain a premium on the sale price as result, this would have been clearly enshrined in the EPO. The EPO does not, in any way, mandate the use of a deprival methodology for valuing easements.

The AER considers the Treasurer's statement to be equally relevant to ETSA Utilities' current claim for easements to be valued using indexed historic costs. The Treasurer had the opportunity as part of ESCOSA's review of its 2005 price determination to set forth the basis upon which any valuation of the easements should have occurred and chose not do so.

In conclusion, the AER does not accept it has made any of the 'three fundamental errors' raised by ETSA Utilities. The AER confirms its draft decision that ETSA Utilities' revaluation of its easements be reversed and the opening RAB adjusted accordingly.

5.3.3 ESCOSA'S treatment of capital contributions

ESCOSA removed $13.5 million of customer contributions from ETSA Utilities fixed asset base as at 1 July 1999. This adjustment was made under clause 7.2(e)(iii) of the EPO. ETSA Utilities disagreed with ESCOSA making this adjustment and considered that the AER must reconsider the matter by virtue of clause 7.3(b)(i) of the EPO.[110]

The AER considers that its processes (through the RFM) are consistent with the requirements of clause 7.3 of the EPO for updating the RAB for the current regulatory control period. At issue is whether the AER can rely on ESCOSA's processes for previous regulatory control periods. The AER notes that clause 7.3(b)(i) of the EPO requires the adjustments to the asset base since the 'commencement date' (being 11 October 1999), to be 'reasonably determined'. The AER does not agree that clause 7.3(b)(i) of the EPO requires it to consider afresh specific asset base adjustments made by ESCOSA with which ETSA Utilities now disagrees. The AER is merely directed to determine these adjustments on a reasonable basis. As a means of doing this, the AER has considered ESCOSA's processes for adjusting the asset base and whether these processes can be relied upon. If those processes are robust, the AER considers that it would be reasonable to rely on the adjustments made by ESCOSA.

The AER considers ESCOSA's processes were robust and extensive, including a draft decision, submissions on the draft decision, a final determination and a review of the final determination. As noted in the draft decision, ESCOSA advised the AER that it had replicated the calculation of the initial asset base as determined by the

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[109] ESCOSA, *2005–2010 Electricity Distribution Price Determination, An application by ETSA Utilities for a review pursuant to section 31 of the Essential Services Commission Act 2002, Decision and Reason for Decision*, May 2005, p. 32.

[110] ETSA Utilities, *Revised regulatory proposal*, January 2010, p.184.

Treasurer[111] and that the Treasurer's calculation included the adjustment for capital contributions in the initial asset base.[112] ESCOSA also noted that ETSA Utilities had not raised the capital contributions adjustment as an issue with it, despite these calculations being shared with ETSA Utilities prior to the release of ESCOSA's 2005 draft decision.

Based on the considerations above, the AER considers that it can rely on the adjustments previously made by ESCOSA to ETSA Utilities' asset base. Accordingly, the AER does not accept ETSA Utilities' proposed adjustment to its opening RAB in relation to this matter.

5.3.4 Adjustments made by the AER

Having confirmed its position in the draft decision to disallow the increases proposed by ETSA Utilities to its opening RAB for easements and certain capital contributions above, the AER has reconsidered how the adjustments for these two matters should be made to ETSA Utilities' RFM.

The AER agrees with ETSA Utilities that these adjustments should be made using June 2004 dollars, rather than June 2005 dollars as in the draft decision. Accordingly, the AER reduced the opening asset base as at 1 July 2004 in ETSA Utilities' RFM by:

- $113.5 million, to reverse the increased valuation of easements by ETSA Utilities
- $16.0 million, to reverse the removal of the capital contributions by ETSA Utilities.

5.3.5 The CPI for 2009–10

As signalled in its draft decision, the AER updated the CPI for the final year of the current regulatory control period in ETSA Utilities RFM using CPI for the year to end March 2010. This update affected ETSA Utilities opening RAB for standard control and alternative control services as at 1 July 2010.

5.3.6 Removal of metering assets

The AER reclassified certain metering services as alternative control services. In its revised regulatory proposal ETSA Utilities maintained the approach used for the draft decision of removing metering assets from the opening RAB in the post–tax revenue model, but leaving them in the RFM.

The AER has accepted the value of these metering assets to be $81 million as at 1 July 2010 and has reduced the RAB for standard control services by this amount. The amount differs marginally from that in the draft decision due to ETSA Utilities revisions to its capex for 2008–09 and 2009–10. The amount also differs from that proposed by ETSA Utilities by $0.5 million due to the revision of the CPI for 2009–10. The reduction in ETSA Utilities' opening RAB is allowed under clause S6.2.1(e)(7) of the NER.

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[111] South Australian Electricity Reform and Sales Unit, submission to the ACCC on the EPO, 11 August 1999.

[112] ESCOSA, email to the AER, 15 October 2009.

5.3.7 Treatment of depreciation for 2015–20

ETSA Utilities accepted the draft decision to determine the opening RAB for the 2015–20 regulatory control period using actual depreciation.[113]

5.4 AER conclusion

The RAB roll forward calculations for ETSA Utilities are set out in table 5.2 and provide for an opening RAB of $2772.4 million for standard control services for the next regulatory control period (as at 1 July 2010).

Table 5.2: AER conclusion on ETSA Utilities' opening RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10[a]
Opening RAB	2504.9	2593.4	2628.9	2701.6	2767.0
Actual net capex (adjusted for actual CPI and weighted average cost of capital)	149.4	122.5	119.9	170.0	193.5
Regulatory depreciation (adjusted for actual CPI)	–61.0	–87.0	–47.3	–104.6	–106.6
Closing RAB	2593.4	2628.9	2701.6	2767.0	2853.8
Difference between actual and forecast capex for 2004–05					–0.3
Return on difference					–0.2
Removal of metering assets					–81.0
Opening RAB at 1 July 2010					2772.4

(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 ETSA Utilities as at 1 July 2010 is $2772.4 million for standard control services.

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 for the commencement of the 2015–20 regulatory control period.

[113] ETSA Utilities. *Revised regulatory proposal*, January 2010, p. 180.

6 Demand forecasts

This chapter sets out the AER's consideration of ETSA Utilities' peak 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

The AER accepted ETSA Utilities' proposed peak demand forecasts and customer number forecasts.

The AER considered that the energy sales forecasts proposed by ETSA Utilities did not provide a realistic expectation of the demand forecast. The AER considered that revising ETSA Utilities' forecast energy sales to the levels shown in table 6.1 provided a more realistic basis for determining the X factors under the weighted average price cap.

Table 6.1: AER draft conclusion on ETSA Utilities' peak demand, customer numbers and energy sales forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15
Peak demand 10% PoE (MW)	3129	3227	3358	3434	3522
Customer numbers	828 162	838 160	846 778	854 779	863 230
Energy sales (GWh)	11 868	12 062	12 399	12 638	12 969

Source: AER, *Draft decision, SA draft distribution determination*, November 2009, p. 98.

6.2 Revised regulatory proposal

6.2.1 Global peak demand

The AER accepted ETSA Utilities' global peak demand forecasts in the draft decision based on AEMO's advice, despite noting that there appears to be substantial differences between the two forecasting models used by ETSA Utilities' consultant, the National Institute of Economic and Industry Research (NIEIR), and AEMO.

ETSA Utilities has accepted the AER's conclusion in relation to its global peak demand forecast, however ETSA Utilities submitted that the demand forecast model relied upon by AEMO and accepted by the AER is not suitable for providing peak demand forecasts based on advice obtained from Frontier Economics.[114]

ETSA Utilities indicated it obtained an updated economic outlook and post model adjustments for demand reductions due to energy efficiency policies underpinning

[114] ETSA Utilities *Revised regulatory proposal*, January 2010, p. 53.

both the sales and global demand forecasts. For this reason, it provided a revised global peak demand forecast.[115]

ETSA Utilities' original global peak demand forecast submitted as part of its regulatory proposal, and its revised forecast are presented in table 6.2.

Table 6.2: ETSA Utilities' global peak demand forecasts (MW)

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15[a]
Original forecast 10% PoE (MW) – including major customers (July 2009)	3129	3227	3358	3434	3522	3.0%
Revised forecast 10% PoE (MW) – including major customers (January 2010)	3159	3274	3361	3410	3477	2.4%

Source: ETSA Utilities, RIN pro forma 2.3.8 (confidential); ETSA Utilities, Response to the AER, 14 September 2009, Issue number AER.EU.23; and ETSA Utilities, *Revised regulatory proposal*, attachment E.10 *NIEIR Global peak demand forecast*, p. 16.
(a) Average annual growth rate calculated based on 2010–11 to 2014–15 data.
Note: PoE means probability of exceedence.

6.2.2 Spatial peak demand

The AER accepted ETSA Utilities' spatial peak demand forecasts in the draft decision based on AEMO's advice.

ETSA Utilities accepted the AER's conclusion that ETSA Utilities' spatial peak demand forecast provides a realistic expectation of the demand forecast.[116] ETSA Utilities stated that it did not alter its spatial peak demand forecast, which is used for planning the capacity of its network.[117] It stated that a reconciliation of global and spatial level demand forecasts was performed to demonstrate the overall consistency between the forecasts and the underpinning economic assumptions.[118]

6.2.3 Energy sales

ETSA Utilities did not accept the AER's conclusion on its energy sales forecast, and the substitution of the energy sales forecast developed by AEMO.[119] ETSA Utilities raised significant concerns about AEMO's modelling approach, hot water sales forecasts, and the treatment of post model adjustments. Based on the advice from its consultants—Frontier Economics and McLennan Magasanik Associates (MMA)—

[115] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 60.
[116] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 56.
[117] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 59.
[118] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 57.
[119] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 55.

ETSA Utilities considered the modelling applied by AEMO was not fit for the purpose of forecasting ETSA Utilities' energy sales.[120]

Economic outlook

ETSA Utilities submitted that it is aware of differences in opinions from various economic forecasters on the economic outlook, especially in the long term. It considered the divergence of economic forecasts had been exacerbated in the current economic environment, and for that reason obtained advice on the economic outlook from a number of sources including NIEIR, Access Economics, and KPMG Econtech (KPMG).[121] ETSA Utilities indicated that its revised baseline forecasts were based on a simple average of Access Economics' and NIEIR's economic forecasts, and were checked against KPMG's forecast.[122]

Hot water heating

ETSA Utilities stated it considered AEMO's approach to forecasting hot water heating energy sales, as accepted by the AER, flawed because:[123]

- the South Australian strategic plan released on 1 January 2007 effectively banned the installation (from July 2008) and replacement (from July 2009) of electric storage hot water services, except in very restricted circumstances
- AEMO's assumption of an average life of 20 years for hot water appliances is significantly greater than the industry expectation of 7–10 years, while ETSA Utilities has used a conservative assumption of 10 years.

Post model adjustments

ETSA Utilities disagreed with the draft decision to exclude the majority of its proposed post model adjustments to be applied to the baseline energy sales forecast. ETSA Utilities engaged MMA to review and report on the reasonableness of ETSA Utilities' post model adjustments. Based on MMA's advice, ETSA Utilities updated its post model adjustments, and considered that it had appropriately addressed the following concerns raised by the AER:[124]

- the risks of double counting price and policy effects
- the risk of double counting the effect of energy efficiency measures where they are already embedded in historical data
- the introduction of bias through the use of post model adjustments that reflect only one aspect of many changes that are occurring in the market.

[120] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 56.
[121] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 57.
[122] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 59.
[123] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment E.3, pp. 5–7.
[124] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment E.3, pp. 7–9.

ETSA Utilities also submitted it had incorporated the effects of the May 2009 Federal Government budget energy efficiency initiatives into its post model adjustments.[125]

A summary of ETSA Utilities' post model adjustments to its baseline energy sales forecasts are presented in table 6.3 below.

Table 6.3: Summary of post model adjustments for energy efficiency effects (GWh)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Government programs						
Price and policy overlap	–	0.1	0.7	1.8	3	4.5
Residential Energy Efficiency Scheme	–7.0	–14.3	–17.4	–18.7	–21.4	–22.9
Thermal insulation programs	–13.8	–12.8	–9.4	–7.0	–2.3	–
Small scale solar photovoltaic units	–9.9	–8.1	–6.7	–6.0	–4.7	–3.4
Appliance efficiency standards						
Residential lighting minimum energy performance standards (MEPS)	–37.1	–22.7	–16	–14.4	–6.6	–2.2
Commercial lighting MEPS	–29.9	–18.3	–13	–11.6	–5.4	–1.8
Air conditioner MEPS	–	–4.5	–4.5	–4.5	–4.5	–4.5
Television and set-top box MEPS	–4.1	1.6	–0.7	–32.9	–39.7	–35.8
Appliance standby power	–14.8	–14.7	–14.7	–14.6	–14.6	–14.5
Total adjustment	–116.7	–210.2	–292	–399.9	–496.2	–576.8

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, table 5.10, p. 75.

Amendments to ETSA Utilities' revised energy sales forecast

ETSA Utilities submitted an update to its revised energy sales forecast (amended forecast) on 10 March 2010. ETSA Utilities stated that it amended the forecast contained in its revised regulatory proposal to correct errors identified during its quality assurance review, including to:

- remove the double counting associated with generation price increases from the assumed network price increases in table 4.3 of the NIEIR report
- re–run the energy sales forecast model to include the price elasticity response for generation, carbon pollution reduction scheme (CPRS) and network price

[125] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 66.

increases, which were excluded from the energy sales forecast contained in the revised proposal.

ETSA Utilities’ original, revised and amended energy sales forecasts and the AEMO forecast, accepted by the AER in its draft decision, are shown in table 6.4.

Table 6.4: ETSA Utilities’ energy sales forecasts (GWh)

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 [a]
ETSA Utilities original forecast	10 977	10 990	10 900	10 688	10 596	–0.9%
AER draft decision forecast	11 868	12 062	12 399	12 638	12 969	2.2%
ETSA Utilities revised forecast	11 174	11 312	11 232	11 216	11 182	0.0%
ETSA Utilities amended forecast	11 144	11 185	10 934	10 714	10 481	–1.5%

Source: ETSA Utilities, RIN pro forma 2.3.8 (confidential); ETSA Utilities, email submission to the AER, March 2010, p. 7; and AER, *Draft decision, SA draft distribution determination,* November 2009, p. 98.

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

6.3 Submissions

The AER received three submissions on demand forecasts from the South Australian Minister for Energy, the Honourable Patrick Conlon, MP (SA Energy Minister), the South Australian Council for Social Service (SACOSS), and the Energy Consumers Coalition of South Australia (ECCSA).

SA Energy Minister

The SA Energy Minister noted the draft decision that a modest positive energy sales growth is a more plausible forecast than ETSA Utilities’ proposal under the emerging environmental constraints.[126]

SACOSS

SACOSS submitted there was a disparity between residential sales forecasts contained in ETSA Utilities’ own consultants’ report and those contained in the revised regulatory proposal, and requested the AER to seek explanation from ETSA Utilities on this issue.[127]

SACOSS was also concerned about the lack of testing for the accuracy of the estimated price elasticity of demand used by both the AER and ETSA Utilities. Based on average residential price and consumption data provided by ESCOSA, SACOSS

[126] SA Energy Minister, *Submission to the AER*, 15 February 2010, p. 1.
[127] SACOSS, *Submission to the AER*, 16 February 2010, p. 3.

submitted that there seems to be little correlation between average residential demand of households and price in the medium term.[128]

SACOSS noted that ETSA Utilities' proposed post model adjustments to its energy sales forecast rely heavily on the work of George Wilkenfeld and Associates (Wilkenfeld). Given that Wilkenfeld had not been consulted directly on the validity of the interpretation of his work, SACOSS considered that the conclusions reached by MMA in relation to post model adjustments were highly sensitive to original and unacknowledged assumptions. SACOSS submitted that the most relevant comparative analysis should be between the base cases of ETSA Utilities/NIEIR's work and the Wilkenfeld work.[129]

SACOSS suggested that the risk sharing under the current revenue control model favours ETSA Utilities rather than consumers. It proposed that given the inelastic nature of average demand per customer in South Australia, it should be assumed residential consumption will remain static at weather corrected per customer averages over the next regulatory control period to forecast residential energy sales. it stated such an assumption will more evenly share the risk between consumers and the business.[130]

ECCSA

ECCSA concurred with the draft decision that ETSA Utilities' proposed energy sales forecasts do not reflect a realistic expectation of demand. ECCSA noted ETSA Utilities had forecast a 0.7 per cent annual reduction in energy consumption, while forecasting an increase in customer numbers. It considered this seemed counter intuitive, and argued that under price cap regulation ETSA Utilities is incentivised to under forecast energy consumption to maximise its revenue.[131]

ECCSA considered AEMO's independent energy consumption forecast accepted by the AER in the draft decision was correct as it was in keeping with recent South Australian trends.[132]

6.4 Consultant review

The AER engaged AEMO to assist in its review of ETSA Utilities' revised energy sales forecast.

6.4.1 Review of input assumptions

AEMO noted that ETSA Utilities developed its revised energy sales forecast based on economic outlooks provided by Access Economics and NIEIR. It noted that ETSA Utilities stated that the average gross state product (GSP) growth forecast from

128 SACOSS, *Submission to the AER*, 16 February 2010, pp. 3–4.
129 SACOSS, *Submission to the AER*, 16 February 2010, p. 4.
130 SACOSS, *Submission to the AER*, 16 February 2010, pp. 4–5
131 ECCSA, *A response*, February 2010, pp. 50–51.
132 ECCSA, *A response*, February 2010, p. 51.

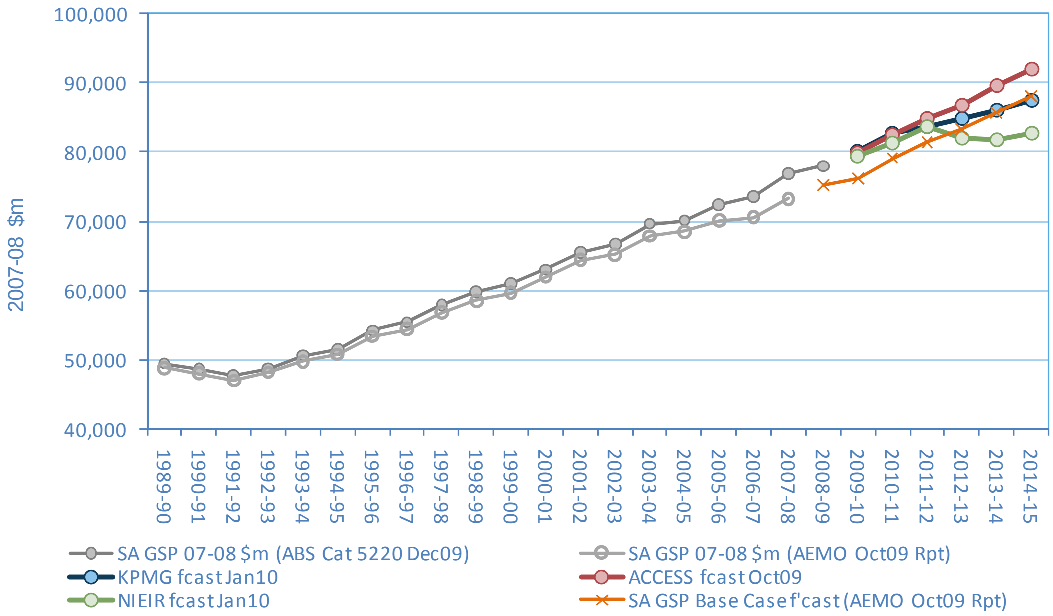
Access Economics and NIEIR's economic outlooks were consistent with the GSP forecast contained in KPMG's economic outlook.[133]

AEMO noted that the three forecasts are different from one another, and are also different from the outlook developed by KPMG in 2009, which was used by AEMO to produce its independent forecast for the AER at the time of the draft decision.[134]

AEMO also noted the Australian Bureau of Statistics (ABS) released updated State Accounts after the draft decision in December 2009. The new publication included data for 2008–09, and significant revisions to historic data after the ABS's adoption of new international standards.[135]

Figures 6.1 to 6.3 illustrate the comparison of historic and forecast data for key drivers of energy demand between difference economic outlooks.[136]

Figure 6.1: South Australia gross state product (GSP)



Source: AEMO, *Second report to the AER review of ETSA Utilities sales and demand forecast*, March 2010 p. 4.

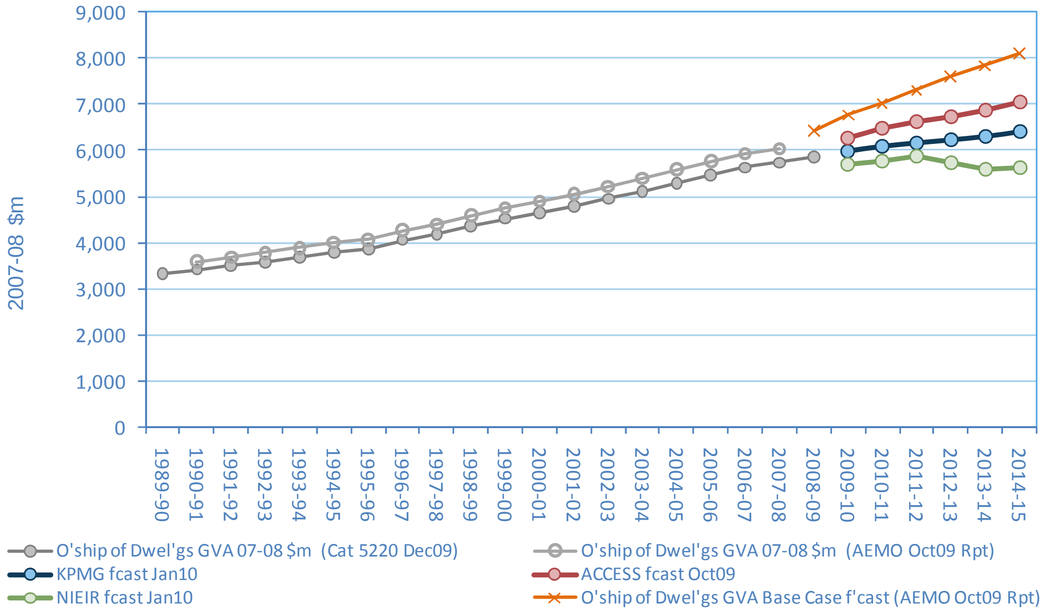
[133] AEMO, *Second report to the AER review of ETSA Utilities sales and demand forecast*, March 2010, p. 2.

[134] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 2.

[135] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 2.

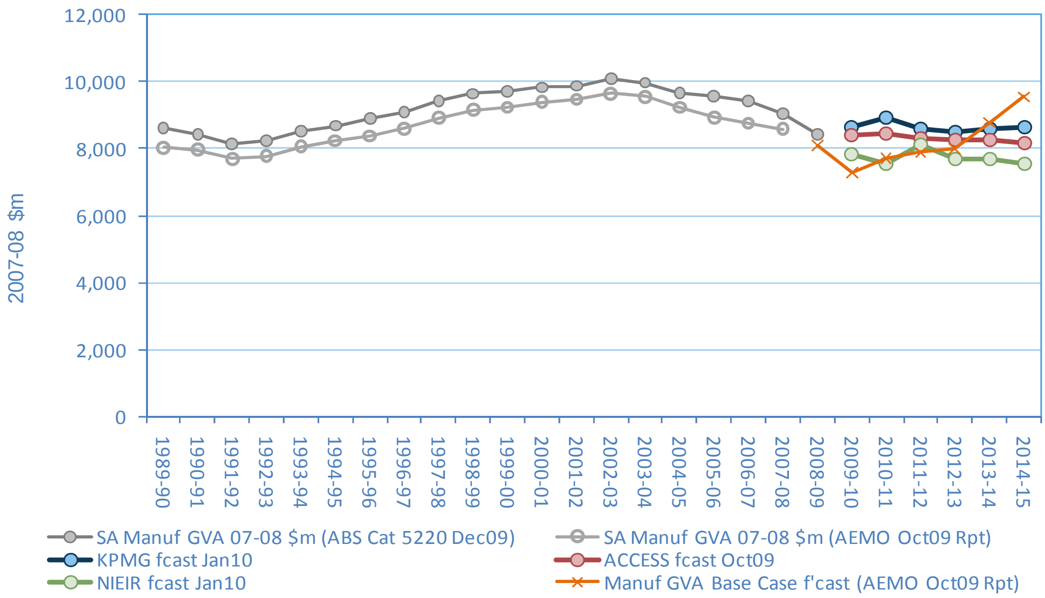
[136] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 2–4.

Figure 6.2: SA ownership of dwellings gross value added (GVA)[137]



Source: AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 3.

Figure 6.3: SA manufacturing sector GVA



Source: AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 4.

[137] Ownership of dwellings consists of landlords and owner-occupiers of dwellings. Owner-occupiers are regarded as operating a business that generates a gross operating surplus. The imputation of a rent to owner-occupied dwellings enables the services provided by dwellings to their owner-occupiers to be treated consistently with the marketed services provided by rented dwellings to tenants. Owner-occupiers are regarded as receiving rents (from themselves as consumers), paying expenses, and making a net contribution to the value of production which accrues to them as owners. See ABS *information paper: Gross state product using the production approach GSP (P) 2007* (Cat: 5220.0.55.002), 14 September 2007.

AEMO made the following observations in relation to the economic data:[138]

- there have been significant revisions to the ABS's historical data
- the overall level of economic activity, reflected in the GSP data, was materially higher for the 2008–09 year than that assumed by AEMO at the time of the draft decision
- NIEIR's revised economic forecast is consistently lower than both KPMG's and Access Economics' revised forecasts
- KPMG's and Access Economics' population forecasts are almost identical, while NIEIR's are materially lower
- although KPMG's revised economic forecasts show the state economy growing to around the same level as previously forecast for 2014–15, there have been material changes to KPMG's forecast of the composition of expected growth on a sectoral level.

In light of these observations, AEMO considered it appropriate to develop new electricity sales models and related forecasts. It stated that the development of its new models was constrained by the range of common variables forecast by all three of ETSA Utilities' economic consultants.[139]

AEMO noted that it is unusual to average different economic scenarios, particularly when the variables being averaged are sub–sets of overall economic activity. AEMO recommended that different economic outlooks be used separately as inputs to the forecasting model, with the resulting sales forecasts averaged if required.[140]

Given the relatively close agreement between KPMG's and Access Economics' forecasts, and the large differences between these forecasts and NIEIR's, AEMO recommended the AER adopt the average of AEMO's energy sales forecasts based on KPMG's and Access Economics' outlooks, which AEMO referred to as its preferred baseline forecast.[141]

6.4.2 Review of retail electricity price assumptions

AEMO noted ETSA Utilities' retail electricity price assumptions include an initial NIEIR price forecast which reflects assumed underlying prices,[142] plus a set of adjustments which reflect ETSA Utilities' assumed network tariff effects on retail prices.[143]

AEMO reviewed NIEIR's underlying price scenario and considered it appeared reasonable. AEMO accepted that it is reasonable to include an allowance on top of

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138 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 5.
139 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 5.
140 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 6.
141 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 6.
142 Price forecasts that only include the effects of the CPRS and renewable energy policies.
143 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 6.

NIEIR's underlying price forecasts for network pricing effects. However, AEMO considered the extent of the allowances made to be unreasonably high. It noted these adjustments were based on ETSA Utilities' initial sales forecasts which AEMO considered to be too low because they are based on more conservative economic assumptions.[144]

AEMO acknowledged that the actual distribution price outcomes will depend on the AER's decision and other policy effects. AEMO provided its baseline energy sales forecast excluding the implied network price increases as presented in table 6.5.[145]

Table 6.5: AEMO baseline energy sales forecast excluding implied network price increases (GWh)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
AEMO March 2010 forecast	11 583	11 814	11 800	11 763	11 747	11 766

Source: AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 30.

6.4.3 Review of water heating sales forecast

AEMO noted ETSA Utilities questioned its assumptions in relation the expected life span of old-style electric storage water heaters in its sales forecast model. Based on advice received from a major plumbing supplier in Adelaide, AEMO considered its assumption of 20 years expected life was reasonable, and that ETSA Utilities' assumption of 10 years understated the expected life of these water heating units. AEMO further noted that a backcast exercise showed its model and assumptions explained actual level of sales over the past five years with a reasonable degree of accuracy. As a result, AEMO considered no adjustment was needed to the hot water sales forecast contained in its previous report to the AER.[146]

6.4.4 Review of ETSA Utilities' revised proposal

AEMO noted ETSA Utilities raised the following issues in relation to AEMO's 2009 energy sales forecast models, based on a report prepared by Frontier Economics:[147]

- the dependent variables used in AEMO's forecasting models are likely to be non–stationary and, as a result, the models may be based on spurious correlations between the variables and will not produce reliable forecasts
- AEMO appears to have had little regard to economic reasoning in the selection of driver variables and dynamic adjustments in developing its models, and instead relied upon identifying the best statistical models. This approach leads to 'unstable' models and that it is difficult to have confidence in models which are changed over time.

[144] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 6–7.
[145] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 8.
[146] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 14–15.
[147] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 9–12.

AEMO acknowledged the potential issues surrounding the use of non-stationary data and the problem of spurious regressions. AEMO therefore reviewed the approach taken in consultation with Monash University, taking into account the Engle-Granger theorem to determine statistically valid long run relationships may be estimated in the manner adopted by AEMO.[148]

AEMO noted that the statistical tests it performed on the electricity consumption data and economic time series for the period 1989–90 to 2008–09 for stationarity found evidence that the data used are I(1). Further the Engle-Granger co-integration test on the data used in the forecast models showed that both sets of data were found to be co-integrated at the 10 per cent significance level. As a result AEMO was satisfied that its October 2009 forecasts were not based on spurious regression models, but represented statistically valid long run relationships between the data.[149]

In developing the revised sales forecasts, however, AEMO elected to remove the issues surrounding the stationarity of data and co-integration by instead estimating new models using first differences of the economic variables and electricity consumption data, as recommended by ETSA Utilities and Frontier Economics.[150]

AEMO noted Frontier Economics' view that its approach leads to unstable models and that it is difficult to have confidence in models which are changed over time.[151] AEMO rejected these claims, as it considered the purpose of the model which it developed for the AER was specifically to forecast ETSA Utilities' electricity sales to 2014–15. It stated earlier models developed by the Electricity Supply Industry Planning Council were designed to forecast overall South Australian electricity sales, so it should not be surprising that different models have been developed. AEMO also noted that historic data is revised from time to time, including ABS and electricity sales data, and that new data becomes available with the passage of time. It considered that both factors necessitate a reassessment of the performance of models from time to time.[152]

Regarding its selection of driver variables, AEMO did not consider the economic driver variables or model structures selected for its preferred models were unusual or exceptional in any way.[153]

AEMO considered it was not surprising that business energy sales are found to respond to an electricity price variable and measures of activity in the manufacturing and other (commercial and services) sectors. AEMO acknowledged that gas prices and weather conditions will also affect electricity sales to the business sector. However, it stated its analysis of the data did not identify these effects as being significant. AEMO noted estimated coefficients for these variables often had the

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148 The Engle-Granger theorem sets out that if non-stationary variables are integrated of order one (I(1)), then it can be established that the variables are co-integrated with one another, and statistically valid long run relationships may be estimated. AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 9.

149 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 10.

150 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 10.

151 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 10.

152 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 10–12.

153 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 11.

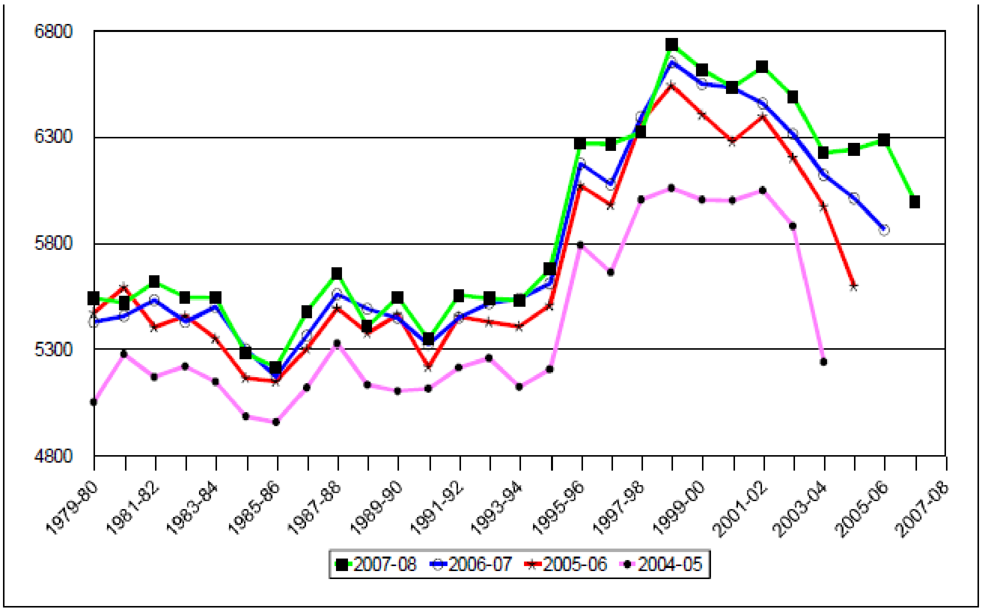
wrong sign and the out-of-sample forecasting performance was typically poorer when these variables were included in potential models.[154]

Similarly, AEMO did not consider it unusual that residential energy sales are found to respond to an electricity price variable, a weather variable and the level of dwelling investment. Dwelling investment increases with the growth of the housing stock, which is where residential electricity consumption occurs. Dwelling investment also reflects changes in the household sector's wealth and income, as well as growth of the population and general economic conditions such as employment levels and interest rates.[155]

Frontier Economics also commented on AEMO's residential sales model including a dummy variable from 1998–99 when the NEM started. AEMO stated in its 2009 report that this effect may reflect a change in the way in which electricity sales data was compiled after the ETSA Corporation was split into separate businesses, or possibly an underlying behavioural change on the part of consumers. AEMO considered this issue further with reference to data presented in NIEIR's January 2010 sales forecast report to ETSA Utilities.[156]

Figure 6.4, reproduced from NIEIR's report, shows changes in average household electricity consumption in recent years for houses of different vintage.

Figure 6.4: Annual residential consumption selected years by dwelling vintage



Source: ETSA Utilities, *Revised regulatory proposal*, attachment E.7, NIEIR Energy sales forecast, January 2010, figure 4.1, p. 29.

Note: X axis measures dwelling vintage and Y axis measures kWh annual consumption.

[154] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 11.

[155] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 11–12.

[156] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 12.

NIEIR attributed large increases in average consumption to an increase in the floor space of new dwellings and increased penetration of air conditioning from the late 1990s.[157]

AEMO agreed that there appeared to have been step changes in recorded average household electricity use over a very short period of time. The driver variables included in AEMO's residential sales forecasting model did not adequately capture these effects and a dummy variable was used instead. AEMO considered the use of a dummy variable to deal with unobserved variables or step changes in behaviour to be common in econometric modelling. AEMO's analysis showed this effect to be important in the out-of-sample forecasting performance of its residential sales model.[158]

Overall, AEMO considered its approach to model development represented a transparent, objective and verifiable way in which to develop models and related forecasts.[159]

6.4.5 Review of post model adjustments

AEMO noted that ETSA Utilities submitted further information, including a report prepared by MMA, to support its inclusion of post model adjustments to its base line (business as usual) energy sales forecast. The adjustments were introduced to capture the potential effect of energy efficiency policies that may not be reflected in the baseline energy sales forecasts.[160]

AEMO reconsidered the post model adjustments proposed by ETSA Utilities, apart from adjustments associated with the introduction of lighting Minimum Energy Performance Standard (MEPS) and the expected increase in installations of solar photovoltaic (PV) units, which it has reviewed previously, including:[161]

- Residential Energy Efficiency Scheme (REES)
- federal insulation programme
- air-conditioner MEPS
- television and set-top box MEPS
- standby power target.

For each proposed adjustment, AEMO examined the baseline forecast used by ETSA Utilities to ensure that any above historic trend growth in energy consumption had been correctly accounted for, and that the energy savings which had already been incorporated in the baseline forecast were not being double counted.[162]

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157 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 12.
158 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 12.
159 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 11.
160 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 33.
161 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 31.
162 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 31–32.

AEMO considered the potential of any rebound effects associated with energy efficiency improvements, and where appropriate estimated the extent of the effects based on empirical evidence.[163]

AEMO also considered the potential impact of electric vehicles on residential energy consumption in South Australia over the next regulatory control period, and incorporated the estimated impacts on energy sales as part of the post model adjustments.[164]

Based on its review, AEMO recommended the post model adjustments to the baseline energy sales forecasts set out in table 6.6.

Table 6.6: AEMO recommended post model adjustments (GWh)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Electric vehicles	0	6.4	12.5	18.6	24.8	31.1
REES scheme	–4.4	–9.9	–15.6	–21.3	–27.1	–32.8
Federal insulation program	–15.9	–16.5	–17.2	–17.8	–17.8	–17.8
Air conditioner MEPS	0	–3.2	–6.4	–9.6	–12.9	–16.2
Televisions and set-top boxes	12.2	27.5	41	20.2	–8.9	–36.6
Standby power	–14.9	–29.5	–44.2	–58.8	–73.4	–88
Solar PV panels	–11.3	–15.1	–18.9	–22.7	–26.4	–30.2
Lighting MEPS	–28.7	–58.2	–88.8	–120.1	–153.9	–189.7
Price and policy overlap	0	0	0	0	0	0
Total adjustments	–63	–98.5	–137.6	–211.6	–295.6	–380.2

Source: AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, table 4, p. 17.

6.5 Issues and AER considerations

6.5.1 Peak demand forecast

The AER notes that ETSA Utilities has not proposed any alteration to its spatial demand forecast accepted by the AER in the draft decision.

The AER reviewed ETSA Utilities' revised global peak demand forecast and notes that the economic outlook underpinning the revised forecast shows a slight

163 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 32–33. AEMO considered that in some circumstances energy efficacy improvements may increase overall energy consumption, and this is termed the rebound effect. For example, replacing existing air conditioners and heaters with more energy efficient systems may increase the overall usage of these appliances due to reductions in running cost.

164 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 43.

improvement compared to that used in the original forecast.[165] The AER notes the level of forecast peak demand is reduced by 45 MW or 1.36 per cent at the end of the next regulatory control period.[166]

The AER notes that the small adjustments in global peak demand have not led to any amendments in spatial demand forecasts, and therefore no adjustments to the capex forecast.[167]

On this basis, the AER accepts ETSA Utilities' revised global peak demand forecast takes into account updated economic data provides a realistic expectation of the demand forecast.

6.5.2 Energy sales forecast

6.5.2.1 Revised regulatory proposal and submissions

ETSA Utilities did not accept the draft decision to reject its energy sales forecast, and submitted an updated energy sales forecast (revised energy sales forecast).[168] ETSA Utilities subsequently submitted a new set of energy sales forecasts (amended energy sales forecast) following its quality assurance review in March 2010.[169] ETSA Utilities stated that the amended energy sales forecast was produced by re–running NIEIR's energy sales forecast model to include the price elasticity response for generation, CPRS and network price increases. These elements had been excluded from ETSA Utilities' revised energy sales forecast.[170]

The AER notes that the amended energy sales forecast is on average around 3 per cent lower over the next regulatory control period than the revised energy sales forecast submitted with ETSA Utilities' revised regulatory proposal.[171]

The AER notes that SACOSS raised concerns about the inconsistency between energy sales forecasts contained in NIEIR's January 2010 report and the revised energy sales forecast.[172] ETSA Utilities stated that the differences were due to weather adjustment.[173] NIEIR indicated that when it prepared the energy sales forecasts, although weather adjustments were applied to the 2008–09 sales data at a customer segment level, they were not applied at a sectoral level due to data availability.[174] NIEIR stated that since it estimated the coefficients for its sectoral energy sales models using weather normalised data, the 2008–09 data was therefore excluded from the coefficient estimation. It noted the 2008–09 sectoral energy sales data was however used as the starting point for calculating sectoral energy sales forecasts. NIEIR stated weather adjustments were applied to the customer segment total to

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165 ETSA Utilities, *Revised regulatory proposal*, attachment E.7, January 2010, p. 21.
166 ETSA Utilities, Response to AER, *AER_weather_price_elasticity.pdf*, March 2010 (confidential).
167 ETSA Utilities, Letter to the AER, Amended sales forecast, March 2010, pp. 2–5.
168 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 55.
169 ETSA Utilities, Letter to the AER, Amended sales forecast, March 2010, p. 7.
170 ETSA Utilities, Letter to the AER, Amended sales forecast, March 2010, pp. 2–5.
171 Calculated based on table 6.4.
172 SACOSS, *Submission to the AER*, 16 February 2010, p. 3.
173 ETSA Utilities, Response to AER, *AER_weather_price_elasticity.pdf*, March 2010 (confidential).
174 Customer segments includes residential, industry, commercial and hot water heating, with residential, industry and commercial customer segments further broken down to sectors such as new and old residential customers, and different industry sectors.

ensure that the residential and commercial sales growth was based on the weather adjusted sales level in 2008–09.[175]

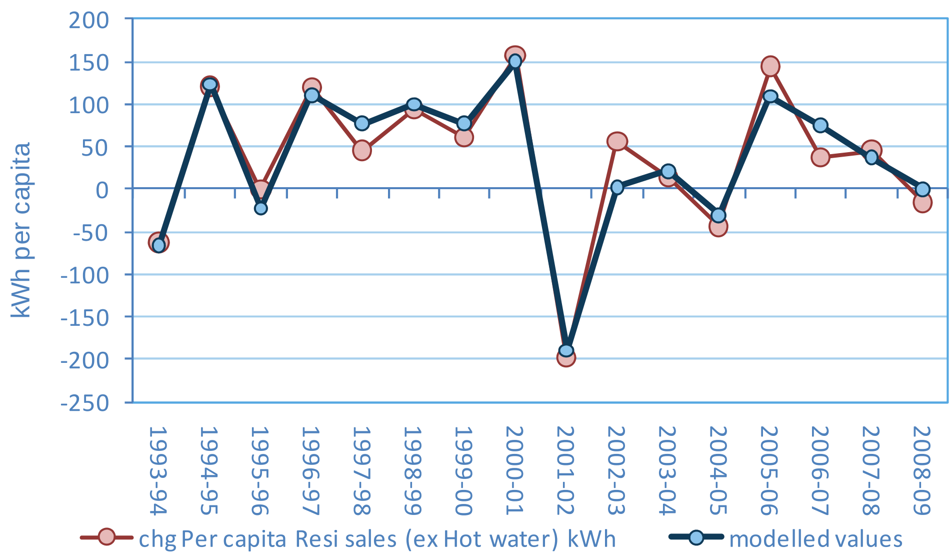
The AER compared the aggregated sectoral energy sales forecasts and customer segment forecasts contained in the amended energy sales forecast and notes that the amount of weather adjustment appears to be consistent with adjustments applied to the revised energy sales forecasts.

Although high level information was provided by ETSA Utilities on NIEIR's weather adjustment methodology, the internal mechanisms of the model and detailed modelling spreadsheet were not available for review. As a result, the AER was unable to draw a clear conclusion on the reasonableness of NIEIR's weather adjustments other than noting the adjustments appeared to have been consistently applied between ETSA Utilities' revised and amended energy sales forecasts.

The AER notes SACOSS expressed concern over the lack of testing for the accuracy of the estimated price elasticity of demand used by both the AER and ETSA Utilities. SACOSS also submitted that the average demand by households seems to bear little correlation to price in the medium term.[176]

The AER notes AEMO included a real retail residential price variable in its residential energy sales model, with the price response by residential customers estimated by the regression model, based on historical energy sales and retail price data over the past 16 years.

Figure 6.5: Actual and fitted value of AEMO's residential sales model (kWh/person)



Source: AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 23.

The AER also notes that based on the actual and predicted values from the residential model shown in figure 6.5, the model provided a good fit to actual historical data. The

175 ETSA Utilities, Response to AER, *AER_weather_price_elasticity.pdf*, March 2010 (confidential).
176 SACOSS, *Submission to the AER*, 16 February 2010, pp. 3–4.

AER therefore considers that AEMO's estimated price response for residential customer appears reasonable.

6.5.2.2 NIEIR forecasting methodology

In order to assess the reasonableness of the NIEIR energy sales forecast model, the AER requested detailed information in relation to NIEIR's model, such as:[177]

- the basic equation for the forecasting model in mathematical form
- definitions of all variables used in the model, and how they are derived
- historical and forecast data for all variables in the model, and the data sources
- modelling spreadsheets and outputs including estimated coefficients, standard errors and residuals.

ETSA Utilities provided a high level description of NIEIR's energy sales model, a report from Frontier Economics on its independent review of NIEIR's forecast methodology, and limited quantitative information for the commerce – wholesale and retail trade energy forecast sub–model.[178] ETSA Utilities stated:[179]

> …given the proprietary nature of NIEIR's models, any further information with regard to request AER.EU.1 is unavailable to ETSA Utilities.

This is confirmed by a letter from NIEIR addressed to ETSA Utilities:[180]

> …NIEIR is not able to make available the estimated coefficient and other model outputs for other sectors (apart from whole sale and retail trade sector), since this would involve releasing proprietary and valuable commercial information. Providing this level of detail in model outputs for all sectors would mean effectively releasing the entire sales model. This model is proprietary to NIEIR and is of considerable commercial value. We (NIEIR) are therefore not prepared to make the information available to ETSA Utilities and/or the AER and can only provide detailed outputs for certain sectors (whole sales and retail sector).

The AER notes that Frontier Economics described the capabilities of NIEIR's modelling system as meeting world class standards, and highlighted that NIEIR has employed advanced econometrics techniques in its parameter estimations.[181] However, the report does not contain information on how and where these econometric techniques have been applied within NIEIR's energy sales model, and does not provide any statistical evidence in relation to the performance of these techniques, such as outputs from post estimation diagnostic tests.

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177 AER, AER information request AER.EU.1, 21 January 2010.

178 ETSA Utilities, response to AER information request, AER.EU.1; NIEIR, *Sales Forecasting – Information for the AER prepared by NIEIR*, February 2010; and Frontier Economics, *Review of NIEIR's forecasting methodology*, February 2010 (confidential).

179 ETSA Utilities, response to AER information request, AER.EU.1, 4 March 2010.

180 ETSA Utilities, response to AER information request, AER.EU.1, NIEIR letter proprietry info.pdf, 4 March 2010.

181 Frontier Economics, *Review of NIEIR's forecasting Methodology*, February 2010, pp. 25–26, (confidential).

The AER would expect to see statistical evidence such as regression outputs and post estimation diagnostic reports to demonstrate the reasonableness of the forecasting model. For example, Frontier Economics stated that NIEIR has appropriately addressed the stationarity issue through log transformation and growth rate equations.[182] However, the AER notes that neither the Frontier Economics report, nor materials provided by NIEIR contained any statistical evidence to demonstrate the model has addressed this particular issue. The AER also notes that AEMO provided full outputs from tests performed on its October 2009 forecasting models to demonstrate the regressions were based on genuine long run relationship between dependent and independent variables.[183]

The AER notes that Frontier Economics stated:[184]

> In some cases, NIEIR have used informed judgement to specify certain parameters, where the estimation procedures produce unreasonable estimates. We accept that it is a common occurrence that the estimation procedures produce unreasonable estimates for some parameters and we believe that the use of informed judgement to produce substitute values for those parameters is in line with normal practice. In this context, the term 'estimation' should be interpreted fairly broadly as applying to the steps taken to determine the parameter values used in the forecasting equations.

The AER accepts that the use of informed judgement in estimation may be reasonable in certain circumstances, for example in estimating a restricted regression based on well established economic theory on the expected sign of a certain coefficient for a dependent variable. However, the AER was unable to review the reasonableness of judgements made by NIEIR as no information was provided on how and on what basis these judgments have been made.

The AER reviewed NIEIR's commerce – wholesale and retail trade energy forecast sub–model, including regression equation, input variable forecasts, and estimated coefficients.[185] The AER notes the regression model was specified based on current growth rate relationships between energy sales and key driver variables, and therefore does not appear to have regard to dynamic effects.[186] The AER notes the estimated coefficients of key drivers are reasonable and have the correct sign. The estimated coefficient for the intercept is positive, suggesting that even with no growth in the key drivers of energy demand, energy sales for the wholesale and retail trade sector will continue to grow at a constant rate. Although this could be due to growth in other factors outside of the model such as population growth, this has not been explained by NIEIR.

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182 Frontier Economics, *Review of NIEIR's forecasting Methodology*, February 2010, p. 26, (confidential).

183 AEMO undertook the Augmented Dickey-Fuller and the Kwiatkowski-Phillips-Schmidt-Shin tests. See AEMO, AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 9–10; and AEMO, Comments on AEMO, *Second Report to AER, ETSA Utilities Sales and Demand Forecasts*, March 2010.

184 Frontier Economics, *Review of NIEIR's forecasting Methodology*, February 2010, p. 26, (confidential).

185 Full regression output and post estimation diagnostic reports were not provided.

186 The regression model did not contain any time lagged variables.

Using growth rate projections of key drivers provided by ETSA Utilities, the AER calculated the forecast growth rates and sales volumes for the commerce – wholesale and retail trade sector.[187] A comparison between the values calculated by the AER and NIEIR's forecasts found large differences, with the NIEIR's forecasts on average approximately 12 per cent below the value calculated by the AER. However, in the absence of further information, the AER is unable to reconcile the differences.

Similar to the commerce – wholesale and retail trade energy forecast sub model, the AER notes that NIEIR's business energy sales models for other sub sectors are also specified based on growth rate relationships between energy consumption and key driver variables. Therefore the AER considers that a high level comparison between the growth rate and key drivers of demand appears to be reasonable.

The AER notes that ETSA Utilities' amended energy sales forecast was developed based on the averaging of economic forecasts provided by Access Economics and NIEIR. The AER notes that the gross value added (GVA) growth rate forecasts used to prepare the amended energy sales forecasts are in general higher compared to the GVA forecasts used by NIEIR in developing its May 2009 forecast; in particular, for the agriculture forestry and fishing, mining, and manufacturing sectors. The AER also notes that NIEIR's real retail electricity price forecast provided to the AER in March 2010 is slightly lower than that contained in ETSA Utilities' regulatory proposal.

The AER compared the retail price, aggregated GVA, and business sales forecasts prepared by NIEIR in May 2009 and January 2010, the results shown in table 6.7.

Table 6.7: Comparison NIEIR May 2009 and January 2010 forecasts (per cent)

Average growth over the period 2010-11 to 2014-15	Business energy sales	Real business retail price	Real aggregated GVA
NIEIR May 2009 forecast	0.8	6.8	1.6
NIEIR January 2010 forecast	0.2	6.2	1.9

Source: ETSA Utilities, *Economic forecast data for AER.xl*s, January 2010; ETSA Utilities, *Regulatory proposal*, attachment D.1 NIEIR Energy sales forecast – Addendum, table 5.1, May 2009; and NIEIR, *Energy sales forecast January 2010*, table 5.2, p. 60.

There appears to be some inconsistency between the average forecast growth in business energy sales and the forecast growth in key drivers.

The AER acknowledges ETSA Utilities' ability to provide information was restricted by the confidential nature of the NIEIR model. Nevertheless, the AER considers that the information requested was necessary to perform a full assessment of NIEIR's forecasting methodology.

[187] Energy sales growth rate forecasts calculated based on summation of estimated coefficient for the intercept, and the products of estimated coefficients of key driver variable and forecast growth rate of key drivers.

The AER further notes that Frontier Economics provided the following comments in its report regarding the analysis of forecasting errors:[188]

> … source of (forecasting) error can be broken down further into several components, choice of the wrong functional form for the forecasting equations, omission from the model of important drivers of the variable being forecast, and errors in the values chosen for the parameters of the forecasting equations.
>
> Parameter values are typically obtained either through econometric estimation or by assigning reasonable values based on experience or studies in other jurisdictions. While it would be valuable to ascertain whether the NIEIR forecasting models suffer from any of these shortcomings, such an investigation would require examination of the detailed model specifications, the raw data used in estimating the models, and the estimation of variants of the current models. Such a detailed examination is beyond the scope of the present review.

The AER considers the above comment reinforces its view that further information is required to perform a proper assessment of the NIEIR model. In the absence of such information, the AER and its consultant's review was effectively limited to the consideration of the reasonableness of input assumptions and post model adjustments.

6.5.2.3 Input assumptions

The AER notes the updated economic outlook provided by KPMG, Access Economics and NIEIR were materially different from the 2009 KPMG economic outlook used by AEMO in developing its energy sales forecast accepted by the AER in the draft decision.

In particular, the AER notes that the outlook for the energy intensive manufacturing sector changed considerably as shown in figure 6.3 and table 6.8, with updated forecasts from both KPMG and Access Economics showing growth in manufacturing GVA flattening out, as opposed to a sharp decline followed by a strong rebound as forecast by KPMG in its 2009 outlook.

The AER also notes the ownership of dwellings GVA forecasts provided by all three forecasters were materially lower than the 2009 KPMG forecast as shown in figure 6.2 and table 6.8, with NIEIR's forecast showing a steeper decline compared to the forecasts from KPMG and Access Economics.[189]

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188 Frontier Economics, *Review of NIEIR's forecasting Methodology*, February 2010, p. 29, (confidential).

189 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 4–6.

Table 6.8: Summary of key driver forecasts (per cent)

Average growth over the period 2010-11 to 2014-15	Manufacturing GVA	Dwelling GVA
KPMG 2009 forecast	5.6	5.1[a]
KPMG 2010 forecast	0.1	1.3
Access 2010 forecast	–0.6	2.4
NIEIR 2010 forecast	–0.6	–0.3

Source: AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, pp. 4–6. Average growth rate calculated based on 2009–10 to 2014–15 data.
(a) Calculated based on dwelling investment index.

The AER notes that NIEIR's updated economic outlook has again been more pessimistic compared to forecasts provided by KPMG and Access Economics as shown in figures 6.1 to 6.3. The AER also notes the NIEIR GSP growth forecast is materially lower than the forecast provided in the latest South Australian Government mid–year budget review, as shown in table 6.9.[190]

Table 6.9: Comparison of GSP growth forecasts (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Mid year budget review	2.3	2.5	3.5	3.5	Not available	Not available
KPMG 2010 forecast	2.6	3.2	1.4	1.2	1.5	1.6
Access 2009 forecast	2.4	3.4	2.6	2.4	3.2	2.7
NIEIR 2010 forecast	1.8	2.3	3.1	–2.0	–0.4	1.3

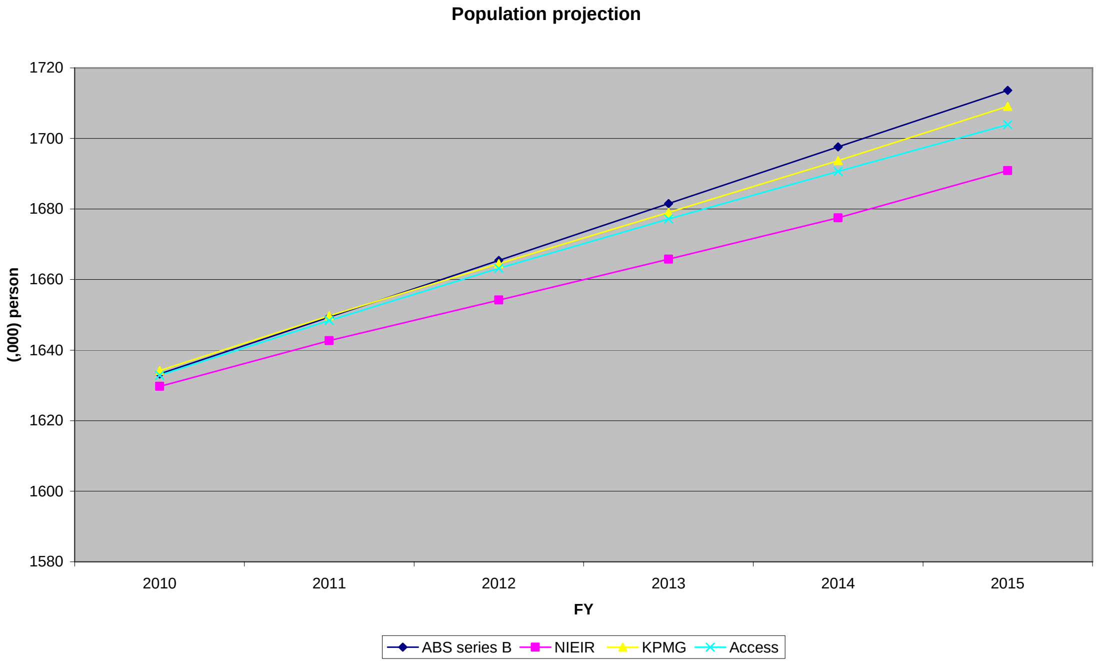
Source: AEMO, *Second report to the AER review of ETSA Utilities sales and demand forecast*, March 2010, p. 4; and Government of South Australia, *Mid year budget review 2009–10*, January 2010.

The AER notes that there has been a slight downward revision to NIEIR's population growth forecasts between its May 2009 and January 2010 reports.[191] The AER also notes that NIEIR's population forecast is materially lower than forecasts provided by KPMG and Access Economics, and the ABS's series B (medium scenario) population growth projection as shown in figure 6.6.

190 AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 2; and Government of South Australia, *Mid year budget review 2009–10*, January 2010.

191 ETSA Utilities, *Regulatory proposal*, May 2009, attachment D.1, NIEIR, Energy sales forecasts, table 3.2; and ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D.1 NIEIR, Energy sales forecasts, table 3.2.

Figure 6.6: Comparison of population growth projections ('000 persons)



Source: AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 4; and ABS, Cat no: 3222.0, *Population Projections, Australia, 2006 to 2101*, Table B4. Population projections, By age and sex, South Australia - Series B.

Given the close alignment between KPMG, Access Economics and the ABS series B population growth forecast over the next regulatory control period, the AER considers that it is appropriate to use KPMG and Access Economics population forecasts as inputs to develop ETSA Utilities' energy sales forecast.[192]

The AER agrees with AEMO that it is unusual to average different economic outlooks from difference sources, as it is unclear that averaging sub–sets of economic activity will provide a sensible overall picture of the economy.[193]

Based on AEMO's advice and its own analysis, the AER considers that NIEIR's economic outlook and population forecast appear too conservative. Therefore the AER accepts AEMO's recommendation that separate energy sales forecasts should be developed based on economic outlook and population forecast provided by KPMG and Access Economics, with the resultant forecasts averaged.

On this basis, the AER considers AEMO's preferred baseline forecast, excluding water heating sales, post model adjustments and implied network price increases represents a more realistic baseline energy sales forecast than ETSA Utilities' amended baseline forecast.

[192] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 4; and ABS, Cat no: 3222.0 - *Population Projections, Australia, 2006 to 2101*, Table B4. Population projections, By age and sex, South Australia - Series B.

[193] AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 6.

A comparison between AEMO's updated baseline forecast and its October 2009 baseline forecast is presented in table 6.10.

Table 6.10: AEMO baseline energy sales forecast excluding implied network price increases, water heating loads and post model adjustments

	2010–11	2011–12	2012–13	2013–14	2014–15
AEMO October 2009 baseline forecast	11 327	11 638	11 970	12 265	12 655
AEMO March 2010 baseline forecast	11 299	11 346	11 403	11 490	11 612

Source: Calculated based on AEMO, *Second report to AER, ETSA Utilities sales and demand forecast*, March 2010, p. 32; and AEMO, *Review of ETSA Utilities sales and demand forecast,* October 2009, p. 54.

The AER notes AEMO's advice that one of the main differences between the energy sales forecasts in AEMO's October 2009 report and the March 2010 report is the change in underlying economic forecasts, in particular the changes in forecast composition of the South Australian economy:[194]

- the average growth rate of SA manufacturing sector GVA has reduced from 2.8 per cent to –0.1 per cent which is the main driver behind the reduction in the business sector sales of around 1000 GWh by 2014–15

- the average growth rate of SA dwelling investment has reduced from 4.5 per cent to 1.9 per cent (for the replaced variable of dwelling ownership GVA) which is the main driver behind the reduction in the residential sector sales of around 500 GWh by 2014–15.

6.5.2.4 Post model adjustments

The AER notes that SACOSS raised concerns in relation to ETSA Utilities' proposed post model adjustments.[195] The AER engaged AEMO to provide a detailed review of the revised post model adjustments, with AEMO's main findings presented in section 6.4.5. The AER notes AEMO's revised post model adjustments are around 400 GWh higher over the next regulatory control period compared to its October 2009 forecasts.

The AER reviewed AEMO's argument for the inclusion of rebound effects associated with efficiency improvements as part of the post model adjustments, and the assumptions AEMO used in estimating the extent of the rebound effects. The AER supports AEMO's approach as it is based on sound economic theory, and considers

[194] AEMO, *Second report to the AER review of ETSA Utilities sales and demand forecast*, March 2010, pp. i–ii. The AER notes that the 'Average growth rates' for 2009 KPMG GVA forecasts appeared to have been calculated based on compound annual growth rate formula using 2008–09 to 2014–15 data.

[195] SACOSS, *Submission to the AER*, 16 February 2010, p. 4.

that the quantum of adjustments made by AEMO in relation to the rebound effects are supported by empirical evidence and therefore reasonable.[196]

The AER considers AEMO's approach to estimate the adjustments needed to capture the above historic trend growth in energy consumption associated with the introduction of electric vehicles, and the increased penetration of televisions and set–top boxes are reasonable. The AER accepts these adjustments should be incorporated as part of the post model adjustments.

The AER reviewed ETSA Utilities' estimated post model adjustment for the introduction of lighting MEPS. The AER considers that the adjustment calculated by ETSA Utilities based on historic and forecast data contained in the relevant regulatory impact statement was reasonable.[197]

The AER notes that, based on NIEIR's advice, ETSA Utilities increased its projection of the energy sales reduction for solar PV installations over the next regulatory control period, mainly driven by the increases in numbers of forecast solar PV installations, as shown in table 6.11 and table 6.12. ETSA Utilities also revised its assumed average PV output capacity per unit from 1.2 KW to 1.4KW.

The AER notes that NIEIR's forecast of PV installations appeared to have been based on the price of renewable energy certificate, feed–in tariffs, and the cost of solar PV installations. However, NIEIR did not provide information on how it has quantified the impacts of above factors on PV installation forecast despite AER's requests for the provision of this information.[198] Instead ETSA Utilities provided historic actual PV connection data, and its own projection of PV installations to 2010–11 based on actual installation data over the period June 2009 to February 2010.[199]

Table 6.11: ETSA Utilities' post model adjustment for installation of solar PVs (GWh)

	2010-11	2011-12	2012-13	2013-14	2014-15
Original proposal	15.5	19	21.6	24.3	26.9
Revised proposal	18.0	24.7	30.7	35.4	38.8

Source: ETSA Utilities,*Regulatory proposal*, Attachment D.1 NIEIR, Energy sales forecast, May 2009, pp. 36–37; and NIEIR, Energy sales forecast January 2010, pp. 37–39.

196 AEMO, *Second report to the AER review of ETSA Utilities sales and demand forecast*, March 2010, pp. 34–35; United Kingdom Energy Research Centre, *The Rebound Effect: an assessment of the evidence for economy-wide energy savings from improved energy efficiency*, October 2007.

197 Department of the Environment, Water, Heritage and the Arts, *Regulatory Impact Statement*, consultation Draft Proposal to Phase-Out Inefficient Incandescent Light Bulbs Equipment Energy Efficiency Committee, September 2008 accessed at http://www.energyrating.gov.au/library/pubs/200808-ris-phaseout.pdf.

198 ETSA Utilities, response to AER information request AER.EU.RP.17, March 2010.

199 ETSA Utilities, response to AER information request AER.EU.RP.17, March 2010.

Table 6.12: ETSA Utilities' forecast solar PV installations (units)

	2010–11	2011–12	2012–13	2013–14	2014–15
Original proposal forecast	15 000	18 000	20 500	23 000	25 500
Revised proposal forecast	20 570	25 570	29 570	32 570	34 570

Source: ETSA Utilities, *Regulatory proposal*, July 2009, attachment D.1 NIEIR, Energy sales forecast, May 2009, p. 37; and NIEIR, *Energy sales forecast*, January 2010, p. 39.

The AER notes the actual installation data (between June 2009 and February 2010) used by ETSA Utilities as the basis for projecting future installations appears reasonable, as it coincides with the Federal Government's introduction of new 'Solar Credits' for the installation of solar systems.[200] The AER also notes that the projected numbers of PV installation of 7000 units in 2009–10 is consistent with most recent trend based on data released by Department of the Environment, Water, Heritage and the Arts (DEWHA).

The AER accepts that the average PV output capacity of 1.4 KW assumed by NIEIR is reasonable based on the average output capacity of exiting PV units in South Australia calculated based on historic data published by the DEWHA.[201]

Based on high level observation, the AER found that there appeared to be a linear relationship between NIEIR's forecast numbers of PV installations and its renewable energy credit (REC) price forecasts. Given that the current REC price of around $40 per MWh and the fixed Small-scale Renewable Energy Certificate price of $40 per MWh as proposed by the Federal Government, the AER accepts that NIEIR's REC price assumption of around $35 to $45 per MWh is reasonable.[202]

Based on the above analysis the AER accepts ETSA Utilities' proposed post model adjustments for the installation of solar PVs.

Based on AEMO's advice and analysis of the revised regulatory proposal, the AER is not satisfied that ETSA Utilities' revised post model adjustments are reasonable. The AER considers that reducing ETSA Utilities' revised post model adjustments to the level shown in table 6.13 below provides a more realistic basis for adjusting the baseline energy sales forecasts to reflect the potential energy efficiency policy impacts over the next regulatory control period.

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200 Australian Government, *Government continues to grow renewable energy industry*, media release, accessed at http://www.environment.gov.au/minister/garrett/2009/mr20090609.html; and Office of Renewable Energy Regulator, *RET process for Owners of Small Generation Units*, accessed at http://www.orer.gov.au/sgu/index.html#table4.

201 Data available from http://www.environment.gov.au/sustainability/renewable/pv/history.html, last accessed 7 April 2010.

202 Australian Government, *Enhanced Renewable Energy Target Scheme*, accessed at http://www.climatechange.gov.au/en/minister/wong/2010/media-releases/February/mr20100226.aspx. Current REC price range derived based on Origin Energy Australia REC price as of March 2010, accessed at http://www.originenergy.com.au/2833/Solar-Credits-Scheme, and current spot price quoted by Green Energy Markets as of 6April 2010, accessed from http://www.greenmarkets.com.au/.

Table 6.13: AER conclusion on post model adjustments for ETSA Utilities' energy sales forecast (GWh)

	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Electric vehicles	0.0	6.4	12.5	18.6	24.8	31.1
REES scheme	–4.4	–9.9	–15.6	–21.3	–27.1	–32.8
Federal insulation program	–15.9	–16.5	–17.2	–17.8	–17.8	–17.8
Air conditioner MEPS	0.0	–3.2	–6.4	–9.6	–12.9	–16.2
Televisions and set-top boxes	12.2	27.5	41.0	20.2	–8.9	–36.6
Standby power	–14.9	–29.5	–44.2	–58.8	–73.4	–88.0
Solar PV panels	–9.9	–18.0	–24.7	–30.7	–35.4	–38.8
Lighting MEPS	–67.0	–108.0	–137.0	–163.0	–175.0	–179.0
Total adjustment	–99.9	–151.2	–191.6	–262.4	–325.7	–378.1

6.5.2.5 Hot water heating energy sales forecast

The AER notes that the main differences between ETSA Utilities' and AEMO's water heating energy sales forecast model was the assumption made on the average useful life of old style electric storage water heaters.

The AER reviewed evidence provided by ETSA Utilities including the MMA report, which estimated an average useful life for electric hot water heaters of nine years, and the communication between MMA and a major supplier of hot water heating systems which estimated an average life of 10 years. The AER also compared ETSA Utilities' assumption against the regulatory impact statement prepared by Wilkenfeld for the Australian Greenhouse Office, which estimated an average life of 10 years.[203] On balance, the AER accepts that ETSA Utilities' assumption of a 10 year expected life for electric storage water heaters is reasonable, as it falls within the range estimated by the sources described above.

The AER also reviewed ETSA Utilities' assumptions in relation to the average annual electricity consumption per customer in the hot water heating sector, and considers those assumptions to be reasonable, as they are comparable to AEMO's assumptions.

The AER's conclusion on ETSA Utilities' hot water heating energy sales forecast is presented in table 6.14.

[203] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment email communications (confidential), November 2009, attachment E.2 MMA, Review of post model adjustment methodology, pp. 83–84, and George Wilkenfeld and Associates, *Regulation Impact Statement: for Consultation Phasing Out Greenhouse-Intensive Water Heaters in Australian Homes*, December 2009, p. 77.

Table 6.14 AER conclusion on ETSA Utilities' hot water heating energy sales forecast (GWh)

	2010–11	2011–12	2012–13	2013–14	2014–15
Hot water heating sales	594	543	493	444	395

6.5.2.6 Retail electricity price forecasts

The AER notes that ETSA Utilities proposed a two staged process for forecasting its energy sales over the next regulatory control period, including the following four steps:

- produce a baseline energy sales forecasts based on retail electricity price projections excluding the impact of network price increases
- use the baseline energy sales forecasts and the proposed revenue requirements as inputs into the post–tax revenue model (PTRM) to calculate the distribution network prices
- calculate the implied distribution and transmission price increases, and add the implied increase to the original retail electricity price projections
- re-run the energy sales forecast model to produce final energy sales forecast.

The proposed methodology was previously reviewed by the AER, which stated that:[204]

> the AER notes that ETSA Utilities' forecasts of key drivers are not reasonable and tend to produce low energy sales forecasts. The AER considers that NIEIR's original (baseline) energy sales forecasts, based upon its forecasts of key drivers, are inappropriate inputs into the PTRM to derive ETSA Utilities' distribution tariffs. As a result, it is not reasonable to subsequently use these tariffs as the basis for updating the initial energy sales forecasts. The AER therefore considers that ETSA Utilities' proposed adjustments to NIEIR's initial retail electricity price and energy sales forecasts are not reasonable.

The AER considers ETSA Utilities' proposed methodology for forecasting its energy sales appears reasonable, as it ensures the internal consistency between the PTRM and the energy sales forecast model. However, given that the AER does not consider ETSA Utilities' revised input assumptions and post model adjustments are reasonable, the AER confirms its draft decision that ETSA Utilities' baseline energy sales forecasts are inappropriate inputs into the PTRM to derive its distribution tariffs.

The AER reviewed ETSA Utilities' baseline retail electricity price forecasts excluding network price increases, and agrees with AEMO's conclusion that the forecast growths in price are reasonable. The AER considers AEMO's baseline energy sales forecast based on NIEIR's baseline retail electricity price growths, key driver forecasts from KPMG and Access Economics, and post model adjustments as

[204] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 93.

presented in table 6.10 provides more realistic baseline energy sales forecast than ETSA Utilities' amended energy sales forecast.

The AER adjusted AEMO's baseline forecast in table 6.10 to reflect its conclusion on post model adjustments as presented in table 6.13, and hot water heating sales as presented in table 6.14. The AER considers the resulting baseline energy sales forecast as presented in table 6.15 should be used as an input into the PTRM to derive the distribution tariffs which are then to be used to produce the final energy sales forecast presented in table 6.17.

Table 6.15: AER conclusion on ETSA Utilities baseline energy sales forecast (GWh)

	2010–11	2011–12	2012–13	2013–14	2014–15
Baseline energy sales forecast	11 741	11 696	11 633	11 610	11 628

6.6 AER conclusion

The AER notes NIEIR's January 2010 energy sales forecast adopted by ETSA Utilities in its revised regulatory proposal does not account for price elasticity responses from customers, a key driver of energy sales. The AER considers this raises questions about the reliability of NIEIR's forecasts, and highlights the risk associated with the lack of transparency of the NIEIR model.

The AER does not consider NIEIR's key driver forecasts, which ETSA Utilities used to develop its amended energy sales forecast, are reasonable, as they are materially lower than the forecasts provided by KPMG and Access Economics.

Based on AEMO's review and its own analysis, the AER does not consider ETSA Utilities' revised post model adjustments are reasonable, as they do not appropriately account for the above historic trend growth in energy consumption associated with the increased penetration of appliances and potential rebound effects associated with efficiency improvements.

In the context of the lack of transparency of the NIEIR model, and its concerns regarding ETSA Utilities' input assumptions and post model adjustments, the AER is not satisfied that ETSA Utilities' amended energy sales forecast submitted in March 2010 reflects a realistic expectation of demand.

The AER considers that AEMO's baseline energy sales forecast adjusted to reflect the AER's conclusion on post model adjustments and hot water heating sales provides a more realistic baseline forecast of ETSA Utilities' energy sales than ETSA Utilities' amended forecast.

The AER's conclusion on ETSA Utilities' baseline energy sales forecast is presented in table 6.16.

Table 6.16: AER conclusion on ETSA Utilities baseline energy sales forecast (GWh)

	2010–11	2011–12	2012–13	2013–14	2014–15
Baseline energy sales forecast	11 741	11 696	11 633	11 610	11 628

Following the AER's modelling request, ETSA Utilities has used the baseline energy sales forecast presented in table 6.16 to derive the final energy sales forecast based on the process outlined in section 6.5.2.6. In other words, the final energy sales forecast is derived based on re-running AEMO's energy sales forecasting model with updated retail electricity price assumptions inclusive of the final distribution price impacts calculated using the baseline energy sales forecast as presented in table 6.16 and the PTRM.

The final energy sales forecast is presented in table 6.17. The amounts determined by the AER have been amended from ETSA Utilities' revised regulatory proposal by the minimum extent necessary to enable it to be approved in accordance with the NER.

Table 6.17: AER conclusion on ETSA Utilities' peak demand, customer number and energy consumption forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	Average annual growth 2010–15 [a]
ETSA Utilities amended forecast (GWh)	11 144	11 185	10 934	10 714	10 481	–1.5%
Final energy sales forecast (GWh)	11 636	11 543	11 416	11 354	11 318	–0.7%
10% PoE Peak demand forecast (MW)	3159	3274	3361	3410	3477	2.4%
Customer numbers forecast	828 162	838 160	846 778	854 779	863 230	1.0%

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

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, AEMO's report and other material, the AER is not satisfied that ETSA Utilities' energy sales forecast provides a realistic expectation of the demand forecast required to achieve the capex and opex objectives. The AER considers that increasing ETSA Utilities' energy sales forecast to the levels shown in table 6.15 provides a more realistic basis for determining the X factors under the weighted average price cap.

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 are the peak demand, customer number and energy sales forecasts specified in table 6.17 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 ETSA Utilities. It also sets out the AER's conclusion on forecast capex for ETSA Utilities for the next regulatory control period.

7.1 AER draft decision

The AER considered ETSA Utilities' proposed capex and was not satisfied that the proposed forecast capex allowance reasonably reflected the capex criteria. In particular, the AER considered that:[205]

- the proposed demand driven capex for the low voltage network upgrade program and major customer connections program did not reflect efficient costs
- ETSA Utilities' proposed asset replacement capex did not reflect efficient costs
- the proposed security of supply capex relating to the Kangaroo Island network security project and elements of the network control project were not demonstrated to be prudent and efficient
- ETSA Utilities' proposed safety related capex for the substation security fencing program and CBD aged asset replacement program did not reflect efficient costs
- the capex relating to superannuation and benchmark equity raising costs did not reflect efficient costs
- the expenditures associated with ETSA Utilities' application of cost escalators did not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives.

Following the adjustments detailed in table 7.1, the AER was satisfied an estimate of $1628 million for ETSA Utilities' forecast capex reasonably reflected the capex criteria, taking into account the capex factors. The AER considered these adjustments were the minimum necessary for it to be satisfied that ETSA Utilities' capex forecast reasonably reflected the capex criteria.

[205] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 174–175.

Table 7.1: AER draft conclusion on ETSA Utilities' capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities proposed gross capex[a]	483.8	580.6	562.5	553.5	542.5	2722.9
Customer contributions	–87.4	–93.8	–85.0	–95.0	–96.0	–457.1
Adjustment to demand driven capex	–20.3	–21.0	–21.9	–23.1	–24.6	–110.9
Adjustment to asset replacement capex	–36.0	–44.4	–50.6	–48.3	–48.1	–227.3
Adjustment to security of supply capex	–5.1	–30.3	–48.7	–19.9	–1.4	–105.4
Adjustment to safety capex	–5.6	–3.4	–2.8	–3.6	–3.4	–18.8
Adjustment to other capex	–0.3	–0.3	–0.4	–0.4	–0.4	–1.8
Adjustment to cost escalators	–16.4	–17.2	–18.8	–24.5	–30.2	–107.1
Adjustment to remove alternative control metering costs	–12.7	–13.5	–12.4	–13.7	–13.9	–66.3
AER net capex allowance	300.1	356.6	321.8	325.0	324.5	1628.2

Source: AER, *Draft decision, SA draft distribution determination*, November 2009, p. 175.
Notes: Totals may not add due to rounding.
(a) Excludes proposed equity raising costs.

The AER also allowed ETSA Utilities to amortise a total amount of $9.2 million ($2009–10) in benchmark equity raising costs for the next regulatory control period.[206]

7.2 Revised regulatory proposal

ETSA Utilities' revised regulatory proposal included a capex allowance of $1793 million ($2009–10) for the next regulatory control period.[207] ETSA Utilities' revised capex proposal is set out in table 7.2.

[206] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 175.
[207] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 109.

Table 7.2: ETSA Utilities' original and revised net capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Original net capex	393.7	485.3	475.3	454.1	440.4	2248.9
Revised net capex	352.5	392.9	351.8	350.1	345.6	1792.8
Difference	–41.3	–92.4	–123.5	–104.1	–94.8	–456.1

Source: ETSA Utilities, *Regulatory proposal*, July 2009, RIN template 2.2.1 and ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN template 2.2.1.
Note: Totals may not add due to rounding.

ETSA Utilities implemented the findings of the draft decision in respect of forecast capex except in the following areas:[208]

- the low voltage network upgrade program
- asset replacement expenditure
- substation fencing and security expenditure
- network control expenditure
- equity raising costs.

ETSA Utilities also included an additional capex requirement related to resources for implementing the negotiating framework for customer connections.[209]

ETSA Utilities' revised capex proposal of $1793 million is approximately $456 million lower than its original capex proposal. Table 7.3 shows the annual profile of ETSA Utilities' revised capex proposal by category.

[208] ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 83–108.
[209] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 106.

Table 7.3: ETSA Utilities' revised net capex proposal by category ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Demand driven	161.4	206.6	156.0	150.5	144.8	819.2
Quality, reliability and security of supply	76.2	86.2	84.6	83.2	77.2	407.4
Safety and environment	25.3	34.3	35.9	35.7	35.0	166.3
Non–network	65.6	57.2	66.6	71.8	79.6	340.8
Superannuation and equity raising costs	24.0	8.6	8.7	8.8	9.0	59.1
Revised total net capex	352.5	392.9	351.8	350.1	345.6	1792.8

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 109.
Note: Totals may not add due to rounding.

7.3 Submissions

The AER received submissions from:

- the South Australian Minister for Energy (SA Energy Minister)
- the South Australian Council of Social Service (SACOSS)
- the Energy Consumers Coalition of South Australia (ECCSA)
- the Energy Users Association of Australia (EUAA)
- Total Environment Centre (TEC)
- EnergyAustralia
- Kangaroo Island Council, Regional Development Australia Board (Adelaide Hills, Fleurieu and Kangaroo Island) and Tourism Kangaroo Island (KI joint parties)
- ETSA Utilities
- UnitingCare Australia (UnitingCare).

The submissions commented on eight aspects of the draft decision and ETSA Utilities' revised regulatory proposal.

Underutilisation of demand management

SACOSS reiterated its view that ETSA Utilities proposed a capex program focussing on very expensive, underutilised infrastructure which failed to meet the demand management needs of the network.[210] SACOSS further submitted that a bigger trial of direct load control technology is warranted, and noted that, while ETSA Utilities is required to consider demand management projects when considering specific network upgrades, this did not ensure the provision of ongoing programs that deliver long term benefits to consumers.[211]

TEC submitted that ETSA Utilities had underutilised the potential of demand management to meet and reduce demand and has instead opted for an inefficient, peak–driven, asset–based expansion program.[212] TEC noted that ETSA Utilities did not appear to have allocated any of its proposed capex and opex to demand management. It stated that the AER should require the implementation of demand management as a first choice over network augmentation where demand management is equal to or more cost effective than building new infrastructure.[213]

UnitingCare submitted that the provision for demand management in the draft decision could be considered miserly, and there is significant potential for substantial cost savings for future capex through sensible demand management strategies. It proposed that consideration be given to a benchmark for demand management expenditure of 0.2 per cent of expected revenue for distribution businesses.[214]

Demand driven capex

ETSA Utilities responded to Origin Energy's submission on its regulatory proposal. Origin Energy requested information about the basis for the projection of an increase in transformer utilisation, given a slight reduction in peak demand growth and a large increase in investment in augmentation. ETSA Utilities explained that this was due to the fact that the number of network assets upgraded in any one regulatory period is relatively small, and a large portion of the proposed augmentation expenditure does not relate to substation transformer upgrades.[215]

ECCSA queried the extent to which the AER had undertaken analytical work to review ETSA Utilities' claim for growth capex, which it considered to be grossly overstated. ECCSA presented its own analysis suggesting the costs of accounting for growth, reflected in the draft decision, are expected to triple in the next regulatory control period. It suggested that the AER should ensure the final capex allowance reflects actual forecast conditions.[216]

The SA Energy Minister submitted that the draft decision to reduce proposed capex on the low voltage network capacity upgrade program would severely hamper ETSA Utilities' ability to improve the performance of its low voltage assets in heatwave

210 SACOSS, *Submission to the AER, ETSA Utilities 2010–2015 distribution price review, Part II: draft determination and revised regulatory proposal*, February 2010, p. 6.
211 SACOSS, *Submission to the AER*, February 2010, p. 8.
212 TEC, *Submission to AER on ETSA Utilities draft distribution determination 2010–11 to 2014–15*, 18 February 2010, p. 2.
213 TEC, *Submission to AER on ETSA Utilities*, 18 February 2010, pp. 2–3.
214 UnitingCare, *Submission to the AER on distribution price reviews*, February 2010, pp. 11–12.
215 ETSA Utilities, *Submissions on ETSA Utilities' regulatory proposal – further information*, 15 February 2010, p. 1.
216 ECCSA, *AER SA electricity distribution revenue reset, the AER draft decision on ETSA Utilities application, a response*, February 2010, pp. 15–16.

conditions. The SA Energy Minister stated the AER has favoured a short sighted reduction in costs at the expense of long term reliability for SA electricity consumers.[217]

Kangaroo Island security of supply project

The KI joint parties noted that deferral of the Kangaroo Island security of supply project until the following regulatory control period risks gambling with the costs of a serious interruption of supply and suppressing potential economic development on the Island.[218] They stated that the existing standby generation on Kangaroo Island cannot be considered as a long term operating source of power, and that the second undersea cable is not intended to provide a higher level of supply redundancy, but rather provides for demand growth. The KI joint parties sought the re–inclusion of the Kangaroo Island security of supply project in the next regulatory control period.[219]

The SA Energy Minister expressed disappointment that the AER had disallowed the Kangaroo Island security of supply project, and stated that the draft decision was based on a misconception that the second undersea cable was intended to provide a higher level of supply redundancy rather than to provide for demand growth. The SA Energy Minister also stated that the draft decision contradicted the intention of the previous regulator (ESCOSA) which considered in 2004 that the project should occur in the 2010–2015 regulatory control period.[220]

Non–system capex

The EUAA considered the proposed increases in non–system capex in the next regulatory control period could not be justified. The EUAA suggested the efficiency of the proposed non-system capex had not been adequately demonstrated as the relationship between non-system capex and workforce growth as an expenditure driver had not been established, and historical non-system expenditures have not been shown to be efficient, for example through a benchmarking exercise.[221]

Benchmarking

The EUAA submitted that the AER had failed to benchmark capex as required under the NER, and urged the AER to use benchmarking to help establish an efficient level of network costs.[222]

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.[223]

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217 SA Energy Minister, *Submission*, 15 February 2010, p. 2.
218 KI joint parties, *AER draft distribution determination for ETSA Utilities*, February 2010, p. 1.
219 KI joint parties, *AER draft distribution determination for ETSA Utilities*, February 2010, p. 2.
220 SA Energy Minister, *Submission*, 15 February 2010, p. 1.
221 EUAA, *Submission to the AER on draft decision on ETSA Utilities regulated revenues and prices 1 July 2010 to 30 June 2015*, February 2010, pp. 18–21.
222 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, p. 21.
223 EnergyAustralia, *EnergyAustralia submission on AER draft determinations for Queensland and South Australia*, 16 February 2010, p. 1.

AER assessment methodology

The EUAA submitted 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. The EUAA submitted that the AER should make greater use of benchmarking to assess efficiency.[224]

Unit costs

The EUAA criticised the AER's assessment of ETSA Utilities' capex unit costs. The EUAA stated that one of the key components in the preparation of a capital expenditure program is to cost the key components of the electricity networks. It stated that PB had no specific requirement to benchmark unit costs, and concluded that the AER's assessment was not based on an independent, critical assessment of unit costs.[225]

Deliverability

ECCSA submitted that the review of the deliverability of ETSA Utilities' capex proposal was limited and incomplete because it did not take into account the spending programs of distribution businesses in other states, which will put pressure on the resources of labour and material available to ETSA Utilities. ECCSA was concerned that ETSA Utilities will retain, at the expense of consumers, the benefit of any underspend should the allowed capex program prove to be undeliverable.[226]

7.4 Issues and AER considerations

7.4.1 Low voltage capacity upgrade program

AER draft decision

The AER noted PB's view that the risk assessment underpinning the low voltage capacity upgrade program overstated the risk, and ETSA Utilities' proposed low voltage planning criteria were more conservative than those applied by other Australian DNSPs.[227]

The AER concluded that the full scope of the proposed low voltage capacity upgrade program had not been appropriately justified given ETSA Utilities' use of inferred rather than actual load assumptions and the resulting impact on volume forecasts. The AER reduced the demand driven capex proposed by ETSA Utilities for the low voltage capacity upgrade program by $103 million ($2009–10). The draft decision continued to provide for a level of capex above historical expenditure, to address constraints in the low voltage network arising from extreme heat events.[228]

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224 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 15–17.
225 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, section 4.3.1, p. 18.
226 ECCSA, *A response*, February 2010, pp. 17–19.
227 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 134.
228 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 134.

Revised regulatory proposal

ETSA Utilities engaged Evans & Peck to provide a technical expert opinion regarding the appropriateness of its approach to low voltage planning.

Evans & Peck found that, although ETSA Utilities' risk assessment appeared appropriate, the low voltage planning criteria were conservative, and recommended ETSA Utilities adopt a revised set of planning criteria.[229] Further, Evans & Peck analysed the sample maximum demand data and recommended that ETSA Utilities assume an average After Diversity Maximum Demand (ADMD) per customer of 3.86kVA, compared to 4.5kVA as originally proposed.[230] Evans & Peck also found ETSA Utilities' forecast replacement growth rate to be inappropriate, and recommended a reduction in assumed load growth from 2.5 per cent to 2.1 per cent.[231]

ETSA Utilities adopted the results of Evans & Peck's review in developing its revised capex proposal. ETSA Utilities proposed a revised forecast for the low voltage capacity upgrade program of $73 million ($2008).[232]

Consultant review

PB reviewed ETSA Utilities' revised regulatory proposal and supporting material provided in relation to the low voltage capacity upgrade program. PB accepted the revised input assumptions for transformer rating criteria, average ADMD and forecast load growth recommended by Evans & Peck as reasonable and prudent for the purpose of testing ETSA Utilities' forecasting methodology. However, PB did not agree with Evans & Peck's findings regarding the expected frequency of extreme weather events or the validity of ETSA Utilities' low voltage transformer replacement forecasting methodology.[233]

Risk assessment

PB noted that Evans & Peck's analysis assessing the likelihood of single day heat events was not representative of the risk that the low voltage capacity upgrade program is intended to address, namely the risk of avalanche failures during extended heatwave events. PB therefore maintained its previous view that ETSA Utilities' risk assessment did not support the full scope of either the original or revised program.[234]

Forecasting methodology

PB noted the view expressed by Evans & Peck that, used in isolation, ETSA Utilities' forecasting methodology based on average ADMD and a count of customer numbers is a relatively poor basis on which to manage a capital program.[235] Notwithstanding this view, PB tested the validity of the revised scope for the low voltage capacity upgrade program using the 2009 actual load monitoring results, ETSA Utilities

229 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 84.
230 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 85.
231 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 85.
232 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 86.
233 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 4.
234 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 4–5.
235 Evans & Peck, *Low Voltage Planning Review*, 23 November 2009, p. 12.

forecasting methodology and the revised input assumptions as recommended by Evans & Peck and adopted by ETSA Utilities.[236]

PB's analysis demonstrated that ETSA Utilities' ADMD based forecasting methodology overestimated the volume of transformer augmentations required by 26 per cent when compared with the required augmentations based on actual 2009 transformer load monitoring data. Further, only 13 of the 34 replacements predicted by the ADMD forecasting methodology coincided with the actual replacements identified from the load monitoring data, representing an accuracy level of 38 per cent for ETSA Utilities' forecasting methodology.[237]

PB also noted that the average installed capacity across the actual load monitoring sample is 4.5kVA per customer, compared with an average installed capacity across ETSA Utilities' distribution transformer population of 5.9kVA per customer. PB stated this indicated the installed capacity within the sample was not representative of the asset population. PB considered that the significantly lower average installed capacity within the sample would tend to overstate the level of augmentation required when the findings are extrapolated across the remaining population.[238]

Conclusion

PB concluded ETSA Utilities' revised load assumptions, and the continued use of a single average ADMD figure to forecast the number of overloaded transformers, results in the overstatement of the volume of transformer capacity augmentations required and does not represent an efficient scope on which to base expenditure forecasts. PB recommended that the draft decision providing an allowance for business as usual expenditure plus an additional 51 targeted distribution transformer replacements per year be maintained.[239]

In calculating its recommended adjustment to ETSA Utilities' proposed low voltage capacity upgrade program capex, PB accepted the proposed inclusion of the $4 million ($2008) planning and load monitoring program previously treated as opex, on the basis of consistency with ETSA Utilities' historical accounting practices.[240] PB also accounted for ETSA Utilities' revised methodology for forecasting the network component of the low voltage capacity upgrade program, based on the proportion of low voltage network to transformer upgrade capex estimated for 2010 with a 2.1 per cent annual growth factor.[241]

PB recommended a reduction to ETSA Utilities' revised proposed capex for the low voltage capacity upgrade program of $37 million ($2008).[242]

AER considerations

The AER reviewed ETSA Utilities' revised proposal for the low voltage capacity upgrade program, and sought advice from PB on the prudence and efficiency of the

236 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 5.
237 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 5.
238 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 6.
239 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 6.
240 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 5–6.
241 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 6.
242 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 7.

proposed capex. The AER notes ETSA Utilities' revised forecast for the low voltage capacity upgrade program is $51 million ($2008) lower than its original forecast, but still $41 million ($2008) above the amount allowed for in the draft decision.[243]

In the draft decision, the AER noted concerns with ETSA Utilities' proposed capex for the low voltage capacity upgrade program in respect of the validity of the supporting risk assessment, the planning criteria used, and the forecasting methodology, including the apparent inaccuracy of transformer replacement volume forecasts.[244]

Risk assessment

The AER notes that ETSA Utilities provided advice from Evans & Peck analysing historical weather data to assess the likelihood of single day extreme weather events. Evans & Peck concluded such events are likely to occur in a five year regulatory control period, and should therefore be considered to be 'business as usual' from a planning perspective.[245] Based on PB's advice and the AER's review of the historical data analysed by Evans & Peck, the AER accepts that this is likely to be the case. The AER notes PB's view that this risk is already accounted for in ETSA Utilities' normal planning processes and emergency maintenance capacity.[246]

However, the low voltage capacity upgrade program is intended to address the risk of avalanche failures associated with extended heatwave events. The AER does not consider the analysis of risks associated with single day heat events presented by Evans & Peck to be relevant to the risk of avalanche failures associated with extended heatwave events. As such, the AER does not consider that ETSA Utilities provided any additional relevant information which addresses the concerns noted in the draft decision regarding the risk assessment underpinning the increase in low voltage capacity capex proposed by ETSA Utilities.

Planning criteria

The AER notes ETSA Utilities adjusted the transformer rating planning criteria associated with the low voltage program based on advice from Evans & Peck. PB considered the revised planning criteria to be consistent with those typically applied by other Australian DNSPs. Further, the AER notes ETSA Utilities also amended its assumptions of average ADMD and replacement load growth, and PB accepted these revised values as reasonable assumptions for the purpose of testing ETSA Utilities' forecasting methodology.[247] The AER considers that ETSA Utilities' revised planning criteria are now consistent with those of other Australian DNSPs. As such the AER considers the revised planning criteria and other input assumptions, are appropriate for testing the validity of ETSA Utilities' low voltage transformer replacement forecasting methodology.

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[243] ETSA Utilities, *Revised regulatory proposal*, *Attachment F.4: Capital expenditure costing*, January 2010.

[244] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 134.

[245] Evans & Peck, *Low Voltage Planning Review*, 23 November 2009, p. 8.

[246] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 4.

[247] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 4.

Transformer augmentation forecasting methodology

The AER notes PB tested the validity of the forecasting methodology and found that it proved accurate in predicting required augmentations in only 38 per cent of instances, and overstated the total required level of replacement by 26 per cent.[248] The AER considers that these results do not support the robustness of ETSA Utilities' forecasting methodology. The AER notes that the majority (62 per cent) of transformer replacements forecast using ETSA Utilities' methodology were not supported by the historical load data from the 2009 heatwave. The AER also notes Evans & Peck's view that ETSA Utilities' methodology for assessing substation utilisation based on average ADMD and a count of customer numbers 'is a relatively poor basis on which to manage a capital program'.[249]

The AER notes PB's comment that the installed capacity across the load monitoring sample of 4.5kVA per customer is substantially lower than the 5.9kVA per customer of installed capacity across the remainder of ETSA Utilities' network. This differential represents over 13 years of replacement load growth based on ETSA Utilities' assumed 2.1 per cent growth, suggesting the installed capacity within the load monitoring sample is not representative of the asset population. The AER notes PB's advice that the significantly lower average installed capacity within the sample would tend to overstate the level of augmentation required when findings are extrapolated across the remaining population.[250]

As discussed above, the AER has reviewed ETSA Utilities' revised regulatory proposal and PB's advice. On this basis the AER considers that ETSA Utilities' methodology for forecasting the volume of transformer augmentations as part of the low voltage capacity upgrade program is not robust, and is likely to significantly overstate the volume of transformer augmentations required to accommodate demand.

Submissions

The AER notes the SA Energy Minister's suggestion that its decision to reduce proposed capex on the low voltage network capacity upgrade program would severely hamper ETSA Utilities' ability to improve the performance of its low voltage assets in heatwave conditions, and that the AER has favoured a short sighted reduction in costs at the expense of long term reliability for SA electricity consumers.[251]

The AER notes that its decision, while reducing ETSA Utilities' proposal for a significant increase in expenditure on the low voltage network in the next regulatory control period, allows for a level of capex above historical expenditure. The AER considers this provides ETSA Utilities with the resources to continue to address constraints in the network arising from significant heat events.

The AER considers ETSA Utilities' proposed costs are based on an inaccurate forecasting methodology and is not satisfied the proposed capex reasonably reflects the capex criteria. In such instances, the AER considers a reduction in proposed capex

[248] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 5.
[249] Evans & Peck, *Low Voltage Planning Review*, 23 November 2009, p. 12.
[250] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 6.
[251] SA Energy Minister, *Submission*, 15 February 2010, p. 2.

costs is in the long term interests of electricity consumers, in accordance with the national electricity objective.

Other low voltage capacity upgrade program components

The AER notes PB's advice that the inclusion of the load monitoring program as part of the capex proposal rather than opex is in accordance with ETSA Utilities' historical accounting practices.[252] The AER also notes that the revised capex forecast for the low voltage network component is materially identical to the allowance included in the draft decision.[253] The AER therefore accepts the proposed capex for the load monitoring program and low voltage network expenditure components of the low voltage capacity upgrade program.

AER conclusion

The AER considers that the program scope for transformer replacements set out in the draft decision, which allows for a level of capex over and above historical expenditures to address constraints arising from extreme heat events, continues to represent a reasonable approach to determining a prudent and efficient level of expenditure which reasonably reflects the capex criteria.

The AER requested ETSA Utilities model the impact of the AER's decision on the low voltage capacity upgrade program. ETSA Utilities advised that the adjustment to forecast demand driven capex is a reduction of $39 million ($2009–10).[254]

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, PB's report and other material, the AER is not satisfied that ETSA Utilities' forecast demand driven capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities' proposed demand driven capex by $39 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.

7.4.2 Asset replacement expenditure

AER draft decision

The AER considered ETSA Utilities' approach to asset replacement, based on age as well as condition, was not demonstrated to be prudent or efficient and did not reasonably reflect the capex criteria.[255] The draft decision applied specific reductions to asset replacement expenditure in the categories of circuit breakers, substation transformers, poles, unplanned lines and conductors, as well as a general reduction to the remaining categories of asset replacement capex.[256]

[252] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 4.
[253] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 6.
[254] ETSA Utilities, response to modelling request, 13 April 2010.
[255] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 144.
[256] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 144–146.

The AER considered that reducing the proposed asset replacement expenditure by $227 million ($2009–10) resulted in expenditure which reasonably reflected the capex criteria, having regard to the capex factors.[257]

Revised regulatory proposal

ETSA Utilities accepted the draft decision on asset replacement expenditure for conductors,[258] but revised its capex forecasts for the remaining categories of asset replacement expenditure:

- circuit breakers—reinstatement of proposed age based circuit breaker replacements where the circuit breaker will be greater than 60 years old in 2015[259]
- substation transformers—reinstatement of proposed asset replacement capex to allow for one additional 66kV (5–20MVA) transformer replacement, the replacement of all remaining Tyree E456 class transformers, and purchase of a spare CBD 66kV to 33kV transformer[260]
- poles—revised forecast based on maintaining the historical ratio of pole replacements to pole treatments in the High Corrosion Zone until mid way through the next regulatory control period, and throughout the next regulatory control period in the Low and Moderate Corrosion Zones[261]
- unplanned lines—revised forecast based on actual expenditure in 2008–09 escalated for network growth and de-rated as appropriate for maintenance[262]
- general—revised forecast based on the application of pro-rata reductions to proposed expenditure for the elements of planned lines and substations asset replacement capex not reviewed by PB, and the maintenance of telecommunications and metering asset replacement capex as originally proposed.[263]

ETSA Utilities' revised asset replacement forecasts result in an increase in total capex of approximately $91 million ($2009–10) compared with the draft decision.[264]

Consultant review

PB reviewed ETSA Utilities' revised regulatory proposal and the additional information provided by ETSA Utilities to support its proposed amendments to the asset replacement capex allowed in the draft decision.

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[257] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 146.
[258] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 82.
[259] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 90.
[260] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 92.
[261] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 96.
[262] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 97.
[263] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 101.
[264] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 101.

Circuit breakers

PB noted ETSA Utilities' revised regulatory proposal for circuit breaker capex reflected the re-inclusion of age based replacements of circuit breakers that will exceed an age of 60 years within the next regulatory control period. This re-inclusion was supported by a report from EA Technologies which considered the relationship between age, condition, probability of failure and risk.[265]

PB accepted EA Technologies' position that the maximum expected life for circuit breakers is in the order of 60 years based on industry expectations. However, PB noted that ETSA Utilities' approach to condition assessment and maintenance demonstrably enabled ETSA Utilities to exceed these life expectations in a number of cases without a demonstrated impact on reliability or maintenance expenditure.[266]

PB also noted EA Technologies did not demonstrate that the age related risk of failure was consistent with the outage performance criteria used by ETSA Utilities to determine the scope of the circuit breaker replacement program. Specifically, the expected failure rate of one failure per year for units 55–65 years old and multiple failures to units greater than 65 years old has not been reported for ETSA Utilities' existing aged circuit breaker population, which includes units over 70 years old. PB therefore considered ETSA Utilities had not demonstrated the assumed failure rates were reasonable.[267]

PB noted EA Technologies' advice assumed that circuit breakers will exhibit a 'wear out' phase characterised by an increasing probability of failure. PB accepted that for a group of similar assets, installed at the same time, in similar environmental conditions, subject to the same periodic maintenance regime and extreme events, the failure pattern of the population would most likely exhibit an increased probability of failure corresponding with the ultimate deterioration of the non–serviceable parts. However, PB considered that the diversity of the operating environment, network location, corrosion zones and ETSA Utilities' established maintenance strategy indicates that the assets have not been operating under similar conditions and in many cases have been subject to periodic overhauls which materially alter the expected life of the asset. PB therefore considered that the age based application of an uncalibrated, assumed end of life failure curve to ETSA Utilities circuit breaker population is not well supported.[268]

PB concluded that, given the advanced nature of ETSA Utilities' existing circuit breaker replacement planning which allows for the clear identification of condition based replacements, no further age based replacements are supported, including by the application of EA Technologies' high level age based approach without specific calibration to ETSA Utilities' network.[269] PB recommended a reduction to ETSA Utilities' revised proposed capex for the replacement of circuit breakers of $25 million ($2008) to the allowance reflected in the draft decision.[270]

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[265] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 8.
[266] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 8.
[267] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 8.
[268] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 9.
[269] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 10.
[270] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 11.

Substation transformers

PB reviewed the information provided by ETSA Utilities in support of the revised capex forecast for substation transformers. It concluded that the allowance for one additional unplanned transformer failure was supported by the recent failure history.[271]

Similarly, PB accepted the proposed increased spares holding for the CBD transformers was a prudent risk management response given the consequence of failure It noted the provision of an additional spare will enable the life of the remaining transformers to be maximised while minimising cost over the next regulatory control period.[272]

In regard to the capex proposed for the replacement of one additional Tyree class E465 transformer, PB considered the basis for this replacement (a 10 year reduction in the retirement age of these transformers to mitigate the risk of failure due to a design weakness) is arbitrary and not well supported as the occurrence of faults is not age related.[273]

PB concluded that the additional capex proposed by ETSA Utilities for the replacement of one extra Tyree class 465 transformer did not represent efficient expenditure. It recommended a reduction to ETSA Utilities' revised capex forecast for substation transformers of $1 million ($2008).[274]

Poles

PB noted ETSA Utilities proposed that historical performance be used as the basis for estimating future refurbishment and replacement volumes for poles. PB considered this essentially reflected a business as usual approach, which would require adjustment to both the replacement/refurbishment mix and the number of poles to be addressed by the program. PB noted ETSA Utilities proposed changes only to the replacement/refurbishment mix, and had not reduced pole volumes to reflect the business as usual approach to the timing of initiating pole treatments.[275]

PB applied ETSA Utilities' advised historical replacement/refurbishment ratios to PB's lower forecast of pole volumes (based on a business usual approach of treatment occurring approximately when a pole reaches the 50 percent metal loss replacement threshold). It noted that expected costs under this scenario were marginally lower than allowed for in the draft decision. However, PB did not consider this to represent an efficient level of expenditure in the long term given the higher proportion of replacements to refurbishments under this approach.[276]

PB concluded that the allowance for pole capex included in the draft decision should be retained on the basis that it represents a prudent and efficient long term approach.

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271 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 11.
272 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 11–12.
273 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 12.
274 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 12.
275 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 13.
276 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 14.

PB therefore recommended a reduction to ETSA Utilities' revised proposed asset replacement capex for poles of $9 million ($2008).[277]

Unplanned lines

PB noted ETSA Utilities' assumptions that significant increases in the level of unplanned line expenditure over the current regulatory control period are expected to continue into the future. PB examined the historical information and established the upward trend in failures was not universal or consistent across asset categories. The failure history for the largest category of expenditure (transformers) demonstrated the recent increase in failure rates was not unprecedented, with a similar level of failures occurring in 2000 and 2001 before a decline in 2002. PB therefore considered that the assumption of continued expenditure growth is not supported. PB stated there is a reasonable basis for expecting ETSA Utilities' future capex on unplanned line components to remain constant or return to historical levels as targeted maintenance practices and capacity augmentations address the assets at highest risk of failure.[278]

PB considered that the assumed linear growth in unplanned lines capex was not supported by ETSA Utilities' failure and expenditure history over the current regulatory control period. PB expressed concern that the 2008–09 historical expenditure used as the basis for ETSA Utilities' forecast was influenced by ETSA Utilities' recent adoption of targeted inspection cycles for distribution line assets. PB also considered that the application of a high level capex forecast without reference to the failure history or known condition of assets as proposed in ETSA Utilities' revised forecast was not supported and was inconsistent with the capex forecasting methodology used for the remainder of the capex proposal.[279]

PB recommended a reduction to ETSA Utilities' revised proposed asset replacement capex for unplanned lines of $10 million ($2008).[280]

General adjustment

PB reviewed ETSA Utilities' revised methodology for calculating the general adjustment to those asset replacement categories not reviewed in detail by PB. It also reviewed the metering asset management plan and two telecommunications asset management plans in order to consider the appropriateness of applying a general reduction to these categories of expenditure.[281]

Based on its review, PB agreed with ETSA Utilities that the metering expenditure was required to meet compliance obligations under the NER and the *Electricity Metering Code* (South Australia). PB noted that the management of ageing meters was based on identifying increasing deterioration within meter groups rather than on scheduled aged based replacement. PB concluded that the metering asset replacement capex category should be excluded from the calculation of the general adjustment.[282]

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[277] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 14.
[278] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 15–16.
[279] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 17.
[280] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 17.
[281] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 18.
[282] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 18–19.

In relation to the telecommunications structures asset management plan, PB noted that there was no risk assessment detailed in the plan and that it was therefore unclear how the expenditure had been prioritised within ETSA Utilities' budgeting procedures. PB noted that this asset management plan also contained a similar corrosion zone based assessment methodology to the poles asset management plan previously reviewed by PB. It stated concerns regarding the limited support for the assumed average life and standard deviation noted for poles was also relevant in this instance.[283]

In relation to the pilot cable asset management plan, the most material component of the telecommunications category, PB was concerned that the need for the proposal to replace 400 km of the pilot cable network with optic fibre was not demonstrated. It stated consideration had not been given to the option of repair rather than replacement, and the risk assessment identified the existing level of risk as low.[284]

On the basis of its review, PB considered that the telecommunications asset management plans reviewed do not demonstrate that the proposed expenditure is efficient, and contain deficiencies in the risk assessments used to prioritise expenditure. PB therefore concluded that the telecommunications category exhibited similar issues to those found for the lines and substations categories, and should not be excluded from the calculation of the general adjustment.[285]

PB recalculated the general adjustment taking into account the exclusion of the metering category and applying the average 48 per cent reduction to the telecommunications category. PB recommended a general adjustment to ETSA Utilities' revised proposed asset replacement capex of $45 million ($2008).[286]

AER considerations

The AER reviewed ETSA Utilities' revised forecast for asset replacement capex and the advice sought from PB on the prudence and efficiency of the expenditures proposed.

In the draft decision, the AER was concerned that ETSA Utilities' proposed asset replacement capex was, in part, driven by age based replacements in addition to condition based forecasts. The AER concluded that an asset replacement approach which is based on condition as well as age was not prudent or efficient, and that the resultant capex forecast did not reasonably reflect the capex criteria.[287]

Circuit breakers

The AER notes that ETSA Utilities proposed to reinstate capex related to age based replacements where the circuit breaker will be greater than 60 years old in 2015.[288]

The AER notes PB agreed that the maximum expected life for circuit breakers is in the order of 60 years based on industry expectations. However, PB also noted that ETSA Utilities' approach to condition assessment and maintenance had enabled

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[283] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 18.
[284] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 18–19.
[285] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 19.
[286] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 19.
[287] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 143–144.
[288] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 90.

ETSA Utilities to exceed these life expectations in a number of cases without any demonstrated impact on reliability or maintenance expenditure.[289]

The AER notes PB's advice that the age related risk of failure described in the report prepared by EA Technologies was not consistent with the outage performance criteria used by ETSA Utilities to determine the scope of the circuit breaker replacement program. In particular, the AER notes that the expected failure rate of one failure per year for units 55–65 years old and multiple failures to units greater than 65 years old has not been reported for ETSA Utilities' existing circuit breaker population.[290] Following its review of PB's advice, the AER has formed the view that ETSA Utilities has not demonstrated that the assumed failure rates are reasonable.

The AER notes PB's conclusion that, given the advanced nature of ETSA Utilities' existing circuit breaker replacement planning which allows for the clear identification of condition based replacements, no further age based replacements are supported.[291] Based on its review of the revised regulatory proposal, and the advice of PB, the AER considers that the circuit breaker replacement capex allowed in the draft decision represents a prudent and efficient level of expenditure. The AER notes the circuit breaker asset replacement capex remains approximately 19 per cent above expenditure in this category in the current regulatory control period.

Substation transformers

The AER notes ETSA Utilities proposed additional asset replacement capex to allow for one additional 66kV transformer replacement, the replacement of all remaining Tyree E456 class transformers, and purchase of a spare CBD 66kV to 33kV transformer.[292]

The AER notes PB's view that the allowance for one additional unplanned transformer failure was supported by the recent failure history.[293] Similarly, the AER notes that PB considered that the proposed increased spares holding for CBD transformers was a prudent risk management response and will enable the life of the remaining transformers to be maximised while minimising cost over the next regulatory control period.[294] Having regard to these considerations, the AER has formed the view that these expenditures reasonably reflect the capex criteria and in particular are a prudent level of replacement capex for these assets in the next regulatory control period.

Regarding the replacement of one additional Tyree class E465 transformer, the AER notes PB's advice that the proposed 10 year reduction in the retirement age of these transformers is arbitrary and not well supported as the occurrence of faults is not age related, but rather relates to the cumulative effect of fault events.[295]

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289 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 8.
290 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 8.
291 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 10.
292 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 92.
293 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 11.
294 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 11–12.
295 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 12.

The AER agrees with PB that, given the failure history, an efficient response to managing the risk posed by these transformers would be to schedule replacement after a serious fault is recorded. The AER therefore considers that the additional capex proposed by ETSA Utilities for the replacement of one extra Tyree class 465 transformer does not represent efficient expenditure in the next regulatory control period.

Poles

The AER notes that ETSA Utilities proposed that historical ratios be used as the basis for estimating future refurbishment and replacement volumes. The AER notes PB's view that this essentially reflects a business as usual approach, which would require adjustment to both the replacement/refurbishment mix and the forecast number of poles to be addressed by the program due to the changed assumption as to the timing of pole treatments. The AER notes however ETSA Utilities proposed changes only to the replacement/refurbishment mix, and has not reduced pole volumes to reflect the business as usual approach to the timing of initiating pole treatments.[296]

The AER notes and has reviewed the advice from PB that, in calculating its replacement ratios, ETSA Utilities double counted defects which may move from a priority three defect in one year to a priority two or one defect in subsequent years, and has also allowed for the replacement or refurbishment of poles with less than 20 per cent metal loss, which is inconsistent with current practice.[297] Based on this advice, the AER does not consider that ETSA Utilities' revised scope for pole asset replacement capex is well supported in terms of prudence and efficiency.

The AER confirms the allowance for pole capex included in the draft decision represents a prudent and efficient long term approach to asset replacement in this category which reasonably reflects the capex criteria.

Unplanned line replacements

The AER notes ETSA Utilities' revised forecast for unplanned line replacement capex is based on actual expenditure in 2008–09 escalated for network growth and de-rated as appropriate for maintenance.[298]

The AER notes ETSA Utilities' assumption of continued expenditure growth in this category is not well supported by the failure history. For example, the AER notes that the failure history for the largest category of unplanned lines expenditure (transformers) demonstrates that the recent increase in failure rates in the current regulatory control period is not unprecedented, with a similar level of failures occurring in 2000 and 2001 before a decline in 2002.[299] The AER therefore does not accept ETSA Utilities' assumption. It considers there is a reasonable basis for expecting that future capex on unplanned line components may remain constant or return to historical levels as targeted maintenance practices and capacity augmentations address the assets at highest risk of failure.

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[296] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 13.

[297] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 13.

[298] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 97.

[299] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 15–16.

The AER notes PB's concern that the 2008–09 historical expenditure used as the basis for ETSA Utilities' forecast was influenced by ETSA Utilities' recent adoption of targeted inspection cycles for distribution line assets. This is evidenced by the increasing maintenance backlog against a stabilising or reducing incidence of failure for the cross arm and insulator asset categories. The AER also notes ETSA Utilities' forecasting methodology relies on a single base year (2008–09), which assumes the historical capex in this year was efficient and without distortions due to the periodic nature of capex requirements.[300]

On the basis of its review and the advice from PB, the AER considers that ETSA Utilities' revised forecast has not been demonstrated to be prudent and efficient with reference to the failure history. The AER considers that the allowance for unplanned lines replacement capex included in the draft decision should be retained.

General adjustment

The AER reviewed ETSA Utilities' revised methodology for calculating the general adjustment to those asset replacement categories not previously reviewed by PB. ETSA Utilities proposed the adjustment be based on the application of pro-rata reductions to expenditure for elements of the planned lines and substations asset replacement capex, and the exclusion of telecommunications and metering asset replacement capex.[301]

The AER accepts ETSA Utilities' revised proposal to calculate the general adjustment to the unreviewed portions of planned lines and substations asset replacement capex based on the pro–rata reduction to the reviewed portions. The AER considers this maintains an appropriate consistency in the level of the reduction within those asset categories.

The AER notes that PB reviewed the metering asset management plan and agreed with ETSA Utilities that the metering expenditure was required to meet compliance obligations under the NER and the *Electricity Metering Code* (South Australia).[302] On the basis of PB's advice and its own review, the AER considers it appropriate that the metering asset replacement capex category should be excluded from the calculation of the general adjustment.

The AER notes PB considered that the telecommunications category exhibited similar issues to those found for the lines and substations categories regarding the suitability of risk assessments and forecasting methodologies. PB considered the proposed expenditure had not been demonstrated to be efficient.[303] On this basis, the AER considers that the telecommunications category should not be excluded from the calculation of the general adjustment. The AER notes that PB recommended that the average reduction applying across the other categories of reviewed expenditure (48 per cent) be applied to the telecommunications category.[304] The AER agrees with

[300] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 16–17.
[301] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 101.
[302] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 18.
[303] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 19.
[304] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 19.

PB and considers this to be a reasonable approach given the similarity of the issues identified across the expenditure categories.

On the basis of its review, the AER considers that the general adjustment to asset replacement capex should be calculated in accordance with the methodology set out in ETSA Utilities' revised regulatory proposal, but accounting for the adjustments to asset replacement capex made by the AER in the preceding sections of this decision and the inclusion of an adjustment to the telecommunications category.

AER conclusion

The AER requested ETSA Utilities model the impact of the AER's decision on asset replacement capex. ETSA Utilities advised that the adjustment to forecast asset replacement capex is a reduction of $93 million ($2009–10).[305]

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, PB's report and other material, the AER is not satisfied that ETSA Utilities' forecast asset replacement capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities' proposed asset replacement capex by $93 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.

7.4.3 Safety expenditure—substation fencing and security

AER draft decision

The AER concluded forecast capex for substation fencing and security should be reduced on the basis that the efficiency of the proposed fencing program had not been demonstrated. The AER considered that a condition based approach to substation fencing should be applied.[306] The AER further concluded that the proposed trial of closed circuit television (CCTV) security at two substations should be completed and evaluated before a capex allowance for a wider rollout as proposed by ETSA Utilities is provided.[307]

Revised regulatory proposal

ETSA Utilities sought an updated legal opinion on its substation fencing obligations, from a public safety point of view, from legal firm Johnson Winter Slattery (JWS). On the basis of this advice, ETSA Utilities submitted a revised forecast for substation fencing and security capex which allows for:[308]

- upgrading security at nine high risk sites, in line with the draft decision
- contributing to the cost of upgrades at 21 shared ElectraNet/ETSA Utilities sites

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305 ETSA Utilities, response to modelling request, 13 April 2010.
306 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 157–158.
307 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 158.
308 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 103.

- upgrading poor condition fencing at 18 medium risk sites to high security fencing
- replacing poor condition fencing at 23 low risk sites with chainmesh fencing
- expenditure on security cameras and security research and development in line with the draft decision.

Consultant review

PB reviewed ETSA Utilities' revised regulatory proposal and the supporting material provided in relation to the substation security and fencing program.

Regarding the proposed capex for the 21 shared ElectraNet/ETSA Utilities sites, PB noted that the specific need to upgrade these sites was not identified in the relevant asset management plan and that no analysis had been provided to demonstrate either the need for or efficiency of the expenditure. PB further noted that no site or fence risk assessments had been provided for eight of the shared sites, and the remaining sites had been assessed as being of medium site risk. In the case of the highest cost shared site the fence risk had been assessed as low. PB considered that the adoption of high security fencing at shared sites should be demonstrated on a case by case basis as reflected in site specific risk assessments. Evidence of this had not been provided in eight cases, and the need for high security fencing was not well supported at the remaining sites.[309]

PB noted that ETSA Utilities' legal advice from JWS identifies that the recommendations regarding 'condition' relate to fences displaying physical damage or deterioration requiring repair. PB agreed with JWS that fences that are seriously degraded or damaged should be replaced and that it may be appropriate (subject to site specific economic and risk assessments) to upgrade fencing at that time to high security fencing. However, PB noted that this interpretation of 'condition' is inconsistent with the definition of 'condition' used by ETSA Utilities in undertaking its fence risk assessments.[310]

PB noted ETSA Utilities had accepted the risk associated with design deficiencies at over 200 sites since becoming aware of them in 2003. PB considered that the timing of the fencing upgrade program was supported by the recent increase in copper theft following the rapid escalation in copper prices in 2007, and to address this need the program should focus on improving security at high risk sites. PB further considered that it is prudent for ETSA Utilities to address known design deficiencies at medium and low risk sites by ensuring the fence risk was low, and that this would be more efficiently achieved through rectification work on existing fences (at a cost of $15 000–$70 000 per site) than by replacing fences to a high security standard (at a cost of $200 000–$400 000 per site).[311]

As a result of its review, PB concluded that the scope of the revised substation fencing and security upgrade program was not efficient and recommended ETSA Utilities' revised capex proposal not be accepted. PB recommended a reduction to ETSA

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309 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 22–23.
310 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 23–24.
311 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 24.

Utilities' revised proposed capex for the substation security and fencing program of $6 million ($2008).[312]

AER considerations

The AER reviewed ETSA Utilities' revised regulatory proposal for safety capex in relation to the substation security and fencing program. The AER notes that ETSA Utilities accepted the draft decision in respect of capex for the installation of security cameras and an upgrade to security at nine sites assessed as high risk.[313]

The AER notes PB's findings that the specific need to upgrade fencing at the shared ElectraNet/ETSA Utilities sites was not identified in the relevant asset management plan and that no analysis had been provided to demonstrate either the need for or efficiency of the expenditure. Further, the AER notes that no site or fence risk assessments had been provided for eight of the shared sites, which were not included in ETSA Utilities' original regulatory proposal, and the remaining sites had been assessed as being of medium site risk.[314] The AER considers that, irrespective of ElectraNet's intentions, capex proposed by ETSA Utilities should be justified by ETSA Utilities, for example through a demonstration of need, timing and cost on a case by case basis, with reference to site specific risk assessments.

The AER notes the advice from JWS, which generally supports the AER's view that the priority for ETSA Utilities is to address the needs of sites assessed as being of high risk of unauthorised entries and injury, with the condition of the existing fence being a secondary issue. The AER agrees with JWS that existing fence condition becomes a consideration in the context of prioritising fencing upgrades at lower risk sites, and that fences that are seriously degraded or damaged should be replaced.[315]

However, the AER notes PB's view that JWS's interpretation of condition is inconsistent with the definition of condition used by ETSA Utilities in undertaking its fence risk assessments. ETSA Utilities identified that the 'condition' assessment related to the presence or absence of specific design features and not the degree of physical damage or deterioration.[316] The AER is therefore concerned at the extent to which the advice from JWS can be considered to support ETSA Utilities' revised capex proposal.

The AER notes PB's advice that ETSA Utilities had accepted the risk associated with design deficiencies at over 200 sites since becoming aware of them in 2003. The AER considers that in addressing these deficiencies, the substation fencing program should focus on improving security at high risk sites. Further, the AER notes and agrees with PB's view that it is prudent for ETSA Utilities to address known design deficiencies at medium and low risk sites by ensuring the fence risk is low, and that this would be more efficiently achieved through rectification work on existing fences than by replacing fences to a high security standard.[317]

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312 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 24.
313 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 103.
314 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 22.
315 JWS, *AER 2010–2015 price reset: substation fencing, 12 January 2010*, p. 9, (confidential).
316 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 23–24.
317 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 24.

On the basis of PB's advice and its own review, the AER considers that the scope of the revised substation fencing and security upgrade program has not been demonstrated to be efficient. The AER considers that the scope of the substation fencing and security program allowed in the draft decision as a prudent and efficient level of expenditure to address identified risks should be maintained.

AER conclusion

The AER requested ETSA Utilities model the impact of the AER's decision on safety capex. ETSA Utilities advised that the adjustment to forecast safety capex is a reduction of $6 million ($2009–10).[318]

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, PB's report and other material, the AER is not satisfied that ETSA Utilities' forecast safety capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities' proposed safety capex by $6 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 Security of supply—network control

AER draft decision

The AER concluded that double counting associated with the engineering and operational staff requirements for the new Network Operations Centre (NOC) should be removed from the capex forecast for the next regulatory control period.[319]

The IT capex forecast associated with the establishment of a temporary disaster recovery site proposed for use over a period of just two to three years was considered to be inefficient and was removed from the capex forecast.[320]

Forecast capex for land acquisition costs associated with the NOC was also removed on the basis that the new NOC will be built on land already owned by ETSA Utilities.[321] In total, the AER reduced the capex associated with the network control project by $10 million ($2009–10).

Revised regulatory proposal

ETSA Utilities reviewed its forecast capex for the network control project and proposed a revised capex forecast. ETSA Utilities accepted the removal of land acquisition costs and some elements of the reductions for NOC resourcing and short life IT capex.[322]

On the basis of updated advice from KEMA Consulting, ETSA Utilities proposed to reinstate approximately $5.8 million ($2008) of the NOC resourcing capex which it

318 ETSA Utilities, response to modelling request, 13 April 2010.
319 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 151.
320 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 151.
321 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 151.
322 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 104.

considered had not beendouble counted.[323] ETSA Utilities also proposed to reinstate $2.4 million ($2008) of the disaster recovery IT capex on the basis that the relevant systems were not short life and would in fact remain in place for disaster recovery purposes after the installation of the new system control and data acquisition (SCADA) system.[324]

Consultant review

PB reviewed the additional supporting information provided by ETSA Utilities in support of its revised capex forecast for the network control project.

On the basis of the specific identification of forecast opex and capex resourcing costs associated with the new NOC provided by KEMA Consulting, PB accepted ETSA Utilities' proposed adjustment to exclude the operating costs which were included in the original capex estimate for this project.[325]

In regard to the IT capex forecast for the network control project, PB accepted ETSA Utilities' statement that the applications included in the duplicated disaster recovery NOC would not be made redundant by the installation of the new SCADA system. However, PB noted that the scope of work for the new NOC includes costs for telecommunications, IT and other infrastructure including uninterruptable power supply (UPS), generator and voice communications which are replicated in the costs for the IT project for the third party disaster recovery facility. PB therefore maintained its view that the duplication of these systems at the third party disaster recovery site in 2010 is repeated for the new NOC site in 2013 and therefore does not represent efficient expenditure.[326]

On this basis, PB recommended a reduction to ETSA Utilities' proposed security of supply capex of $2.4 million ($2009–10) to remove the duplication of costs with the third party disaster recovery IT project.[327]

AER considerations

The AER reviewed the documentation provided by ETSA Utilities in support of its revised regulatory proposal, and sought advice from PB about the prudence and efficiency of proposed expenditures.

The AER notes that ETSA Utilities sought advice from KEMA Consulting to clarify the extent of double counting of labour costs for the new NOC across opex and capex. KEMA Consulting advised that an amount of $1.1 million ($2008), previously proposed by ETSA Utilities as capex, related to staffing costs for Network Controllers and Network Dispatchers, and should therefore be considered opex.[328] ETSA Utilities reflected KEMA Consulting's advice in its revised regulatory proposal. Having reviewed the revised regulatory proposal and the advice from PB and KEMA

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323 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 104.
324 ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 104–105.
325 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 20.
326 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 21.
327 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 25.
328 KEMA Consulting, *Clarification of operational staff costs for network control projects*, 10 December 2009, pp. 1–2.

Consulting, the AER is satisfied that ETSA Utilities' revised forecast capex for the network control project reflects an appropriate estimate of staffing costs.

The AER notes PB's advice that the scope of work for the new NOC includes costs for telecommunications, IT and other infrastructure which are replicated in the costs for the IT project for the third party disaster recovery facility.[329] The AER accepts PB's analysis and considers it to be inefficient for ETSA Utilities to incur capex costs, for substantially the same purpose, twice within the first three years of the next regulatory control period. The AER therefore maintains its view that the IT related capex proposed for use over a period of just two to three years should be removed from the capex forecast.[330]

AER conclusion

The AER requested ETSA Utilities model the impact of the AER's decision on security of supply capex. ETSA Utilities advised that the adjustment to forecast security of supply capex is a reduction of $2 million ($2009–10).[331]

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, PB's report and other material, the AER is not satisfied that ETSA Utilities' forecast security of supply capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities' proposed security of supply 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 Customer connections—negotiating framework

Revised regulatory proposal

ETSA Utilities considered that the required changes to the negotiating framework for negotiated distribution services set out in the draft decision would significantly increase the administrative resources required for the provision of a negotiated distribution service.[332]

ETSA Utilities' revised regulatory proposal included an additional $1.2 million ($2008) per annum of labour within the customer connection capex forecast to accommodate the increased resources required to negotiate the provision of negotiated distribution services under a revised negotiating framework.[333]

AER considerations

The AER's detailed consideration of ETSA Utilities' response to the revised negotiating framework for negotiated services is discussed in chapter 3 of this decision.

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329 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 21.
330 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 151.
331 ETSA Utilities, response to modelling request, 13 April 2010.
332 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 28.
333 ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 28 and 106.

As set out in section 3.4.4, the AER does not accept ETSA Utilities' proposal for additional capex as a result of the AER's approach to negotiated distribution services. In summary, the AER considers the proposed additional capex does not relate to standard control services, and the NER do not require the AER to approve regulated revenues for negotiated distribution services.

AER conclusion

The AER requested ETSA Utilities model the impact of the AER's decision on customer connection capex. ETSA Utilities advised that the adjustment to forecast customer connection capex is a reduction of $6 million ($2009–10).[334]

For the reasons discussed and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal and other material, the AER is not satisfied that ETSA Utilities' forecast customer connection capex reasonably reflects the capex criteria, including the capex objectives. The AER considers that reducing ETSA Utilities' proposed customer connection capex by $6 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.

7.4.6 Cost escalators

AER draft decision

The AER did not accept the methodologies used to develop ETSA Utilities' real cost escalators. The AER did not consider ETSA Utilities' escalation rates for labour costs were acceptable because, amongst other things:

- the forecasts were no longer based on the latest available information
- the internal labour growth forecasts explicitly reflected the impact of ETSA Utilities' internally determined performance and incentive initiatives
- the forecasts did not appear to accurately consider the actual composition of ETSA Utilities' internal and contract service labour resources by labour type.

The AER did not consider ETSA Utilities' escalation rates for materials were acceptable because they did not reflect the most up to date market–based forecasts of future materials costs. The AER also considered ETSA Utilities' base year costs had been inappropriately escalated for 2.5 years of cost growth instead of only two years.

ETSA Utilities' forecast capex was reduced by $107 million ($2009–10).[335]

Revised regulatory proposal

ETSA Utilities adopted all of the AER's recommendations in relation to labour escalation, with the exception of amendments to the manner in which impacts of

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[334] ETSA Utilities, response to modelling request, 13 April 2010.
[335] AER, *Draft decision, SA draft distribution determination*, November 2009, p.127.

ETSA Utilities' Enterprise Bargaining Agreement (EBA) were accounted for in 2008–09 and 2010–11.[336]

ETSA Utilities submitted its application of the AER's real weighted average internal labour escalator in its revised regulatory proposal alleviates the AER's concerns with respect to ETSA Utilities' treatment of employee bonuses and incentives.[337]

ETSA Utilities accepted the AER's approach to calculating real cost escalators for construction and other outsourced services and updated its construction related services escalator with the latest available data released from the Construction Forecasting Council.[338]

For materials cost escalation, ETSA Utilities accepted all of the AER's recommendations from the draft decision, except using London Metals Exchange (LME) forward contract prices for 63 months and 123 months for aluminium and copper, on the basis that these are too thinly traded to be reliable.[339] ETSA Utilities proposed using Consensus Economics long term forecasts instead[340] and used updated data in calculating its materials cost escalation rates.[341]

Consultant review

The AER engaged Access Economics to provide an update on its growth forecasts for general state labour price indices (LPIs) and the EGW (electricity, gas and water or utilities) sector in NSW, Victoria, Queensland, South Australia, ACT and nationally.[342] Access Economics noted changing economic conditions were the key driver for revisions to forecasts published in its September 2009 report[343] and that a number of technical changes to historical variables have also impacted the forecasts.[344]

Access Economics projected South Australia's economic growth to record a solid recovery through 2010 and for general labour cost growth to peak in mid–2011 before reverting back toward the national average.[345] Access Economics considered that labour costs in South Australia's EGW[346] sector would rise faster than that seen nationally, in order for employers to retain current and attract new workers.[347]

Access Economics' forecasts for general labour and EGW labour are set out in table 7.4 below.

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336 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108, attachment F.10, pp. 7–8.
337 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 133.
338 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.
339 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.
340 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, pp. 3–4.
341 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.
342 Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010.
343 Access Economics, *Forecast growth in labour cost*, 16 September 2009.
344 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.
345 Access Economics, *Forecast growth in labour costs*, 16 March 2010, pp 30–31.
346 The AER notes the release of 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.
347 Access Economics, *Forecast growth in labour costs*, 16 March 2010, pp. 80–81.

Table 7.4: Access Economics real labour escalation rates for general labour and the EGW sector in South Australia (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
General	0.7	0.8	1.1	0.2	0.5	1.2	1.5
EGW	1.7	2.3	1.2	0.3	0.5	1.2	1.6

Source: Access Economics, *Forecast growth in labour costs*, 16 March 2010, p. 79.

Submissions

ECCSA raised concerns in relation to real cost escalation. In particular, ECCSA stated the AER view appears to be that any real increase in costs is justification for an increased allowance to the regulated business.[348] In relation to wages growth, ECCSA considered the AER has taken an overly conservative approach.[349] ECCSA stated the AER must include a productivity gain to offset wage growth, in keeping with the approach adopted in previous jurisdictional decisions.[350]

In relation to materials cost escalation, ECCSA stated the AER should not adopt an approach of forecasting materials price growth. ECCSA stated such forecasts will invariably be conservative in favour of the businesses. ECCSA therefore proposed the AER should only make allowances for defined step changes in business conditions.[351]

AER considerations

The details of the AER's assessment of the cost escalators proposed by ETSA Utilities are set out in appendix G of this decision.

The AER notes ETSA Utilities disagreed with how the impacts of its EBA were accounted for by the AER in 2008–09 and 2010–11.[352] For 2008–09, ETSA Utilities provided actual EBA impacts which the AER has used in its modelling instead of EGW data provided by Access Economics. However, for 2010–11 EBA impacts, the AER confirms its view that it is reasonable to adopt current EBA wage increases up until 2009–10 only, in order to maintain the incentives on DNSPs to negotiate efficient labour outcomes. The AER notes that its modelling for the draft decision incorrectly included EBA rates to December 2010, thereby impacting labour escalation rates in 2010–11. The AER has corrected the modelling error in relation to EBA impacts in 2010–11 for this decision.

Notwithstanding the AER's view that EBA rates should not automatically be reflected in the escalation rates for the next regulatory control period, the AER also considers that the EBA rates do not provide a realistic expectation of ETSA Utilities' labour costs in the next regulatory control period. This is because, (as discussed in appendix G), the 2008 EBA came into effect prior to the global financial crisis (GFC),[353] and

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348 ECCSA, *A response*, February 2010, p. 19.
349 ECCSA, *A response*, February 2010, p. 20.
350 ECCSA, *A response*, February 2010, p. 21.
351 ECCSA, *A response*, February 2010, p. 21.
352 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108, Attachment F.10, pp. 7–8.
353 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

therefore would not reflect the impact and uncertainty of GFC-associated economic conditions on labour growth.

In relation to materials cost escalation, the AER notes that ETSA Utilities accepted all of the AER's recommendations except the use of 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 ETSA Utilities to use Consensus Economics long term forecasts to establish cost escalators for aluminium and copper.

The AER notes the concerns raised by ECCSA that the AER took a conservative approach for wage cost growth and considered state-wide wage increases be treated as a benchmark for productivity. The AER considers that productivity adjustments can be an important factor in forecasting actual business costs and notes this approach is consistent with previous regulatory decisions.[354] The AER further notes Access Economics considers productivity factors as a key driver of wage differentials and has incorporated productivity into its modelling.[355] The AER considers the application of Access Economics' productivity factors into its model is reasonable, reflecting a realistic expectation of labour cost.

Regarding the suggestion that the AER should not forecast changes in real materials costs incurred by the DNSPs, the AER notes that one of the criteria that must be satisfied is that the capex and opex forecasts must reasonably reflect a realistic expectation of cost inputs required to achieve the capex and opex objectives.[356] The AER maintains its view from previous regulatory decisions that cost escalation at CPI does not reflect a realistic expectation of the movement in some of the input costs faced by electricity network service providers. The AER also notes that the real cost escalation regime is applied symmetrically, ensuring that network service providers recover the efficient costs of real increases, while end users receive the benefit of real cost reductions. To illustrate, the AER notes that in the revised materials cost escalators proposed by ETSA Utilities, as shown in table G.2 of appendix G, growth in real materials costs is negative for five of the seven years over which base year costs are escalated.

AER conclusion

Table 7.5 sets out the AER's conclusions on ETSA Utilities' real cost escalators over the next regulatory control period. More detailed information on the AER's assessment is detailed in appendix G of this decision.

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key turning point for the Australian economy was the change that swept through the global economy in mid–September 2008.

354 AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 492.

355 Access Economics, *Forecast growth in labour costs,* 16 March 2010, Appendix C, p. 106.

356 NER, clauses 6.5.6 (c) and 6.5.7(c).

Table 7.5: AER conclusions on ETSA Utilities' 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	0.72	0.738
Inflation rate	1.46	3.00	2.50	2.75	2.50	2.50	2.50
Materials[a]	–3.05	–3.84	9.32	–0.46	–0.06	–1.02	–1.34
Labour	1.12	1.80	0.57	0.29	0.52	1.18	1.56
Services – construction related	0.15	1.59	0.63	0.96	2.04	2.21	1.22
Services – other outsourced	0.94	1.17	1.11	0.25	0.51	1.22	1.54

Source: AER analysis.

(a) This composite materials cost escalator is based on ETSA Utilities' application of the materials cost inputs above. Source, ETSA Utilities, *email – expenditure modelling request*, 13 April 2010.

7.4.7 Equity raising costs

AER draft decision

The AER included an allowance of $9.2 million ($2009–10) in ETSA Utilities' capex allowance for benchmark equity raising costs. This amount excluded indirect equity raising costs, and the impact of capital contributions on the tax payable in the cash flow analysis. The AER determined a standard life of 52.3 years (based on a weighted average of total asset classes by value) for amortising equity raising costs in the post–tax revenue model (PTRM).

Revised regulatory proposal

ETSA Utilities noted that it had incorporated the draft decision on direct and indirect equity raising costs in its revised regulatory proposal but that fact should not be construed as acceptance of the AER's reasoning.

ETSA Utilities accepted that capital contributions should not be considered as a distributable cash flow, but noted the tax payments on capital contributions should be reflected in the tax allowance provided in the PTRM. ETSA Utilities amended its cash flow model used to estimate equity raising costs to recognise that capital contributions are a revenue item and subject to taxation, but not available for distribution.

ETSA Utilities did not accept the revised standard life, for amortisation purposes, used by the AER in the PTRM.

AER considerations

Direct equity raising costs

The AER notes that ETSA Utilities considered several aspects of the AER's method for estimating direct equity raising costs were unclear, and specifically mentions the sampling of firms and relevant calculations.[357]

The AER considers that information presented as part of the regulatory process should be as transparent as practicable,[358] and endeavoured to provide this information in appendix J dealing with benchmark equity raising costs attached to the draft decision.[359] For example, the draft decision details the sample of 20 firms used to determine the benchmark for dividend reinvestment plans.[360] The AER did not list the firms in the sample of seasoned equity offerings (SEOs), and this may be the reason ETSA Utilities views the sampling of firms to be unclear. Accordingly, these firms are listed in table 7.6.

Table 7.6: Firms included in AER analysis of direct costs of seasoned equity offerings (2007–08 and 2008–09)

Alumina	Gunns	Rio Tinto
Amcor	Iluka Resources	Sino Gold
ANZ	Incitec Pivot	St Barbara
Asciano	Lihir Gold	Westfield Group
Bendigo and Adelaide Bank	Lynas Corp	Elders Limited
BlueScope Steel	Mount Gibson Iron	Transpacific
Boart Longyear	Newcrest Mining Limited	Valad Property
Commonwealth Bank	Nexus Energy	Windimurra Vanadium
GPT	Orica	
Grange Resources	Photon	

Source: AER analysis of Bloomberg, annual reports.
Note: The AER identified candidate firms using equity raising figures from Bloomberg, then reviewed the firm's annual reports for the 2007–08 and 2008–09 financial years to identify direct equity issuance costs associated with SEOs.

The AER confirms that the relevant calculation was to take the median of the 30 SEOs from the firms listed in table 7.6 for 2007–08 and 2008–09.[361] The AER notes that ETSA Utilities has not specified other components of the draft decision regarding benchmark equity raising costs which it considers to be unclear.

357 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 107.
358 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 540.
359 AER, *Draft decision, SA draft distribution determination*, November 2009, appendix J.
360 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 565.
361 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 568. Some firms undertook multiple SEOs.

The AER considers that its approach to calculating the benchmark equity raising costs produces the best estimate available. The AER notes that ETSA Utilities has accepted the direct equity raising unit rates specified in the draft decision, which vary based on the source of the equity:

- for retained earnings, no equity raising costs
- for dividend reinvestment plans, equity raising costs of 1 per cent
- for SEOs, equity raising costs of 3 per cent.

Modelling of equity raising costs and impact of capital contributions

The AER notes that ETSA Utilities' concern regarding the treatment of capital contributions in the calculation of equity raising costs appears to be a misunderstanding of the modelling process undertaken by the AER. ETSA Utilities stated the AER had failed to provide an allowance for the tax paid on capital contributions in the calculation of equity raising costs. The AER disagrees with ETSA Utilities in this regard.

The AER prepared a separate PTRM to model benchmark equity raising costs in order to remove the impact of capital contributions on the cash flows, as outlined in the draft decision:[362]

> The modelling process for removing the impact of capital contributions has been done to ensure each of the cash flow items are considered on a 'like for like' basis. It would be inappropriate to include the impact of capital contributions in the tax amount because it is not included in each of the other items that are affected such as revenue and the capex requirement.

This difference in the modelling process is shown in the way that net capex (exclusive of capital contributions) is used as an input to the separate PTRM employed for modelling equity raising costs. However, in the standard PTRM (which is used to determine the final expected revenues, and may include the modelled benchmark equity raising cost), the capex and capital contributions inputs are used in a different manner specifically to recognise that capital contributions are a revenue item and subject to taxation—that is, a tax allowance is provided for in respect of capital contributions. Accordingly, the AER maintains the view it arrived at in the draft decision and does not accept that an adjustment needs to be made in the separate PTRM used to model benchmark equity raising costs.

Standard life for amortisation purposes

The AER's assessment of the appropriate standard life is discussed in chapter 10 of this decision.

AER conclusion

The AER considers the revised benchmark equity raising cost allowance associated with ETSA Utilities' forecast capex, as set out in table 7.7 represents the efficient

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[362] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 166.

costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capex objectives in the next regulatory control period.

For the reasons discussed and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal and other material, the AER is not satisfied that ETSA Utilities' proposed equity raising cost reasonably reflects the capex criteria, including the capex objectives. The AER considers that setting the benchmark equity raising costs for ETSA Utilities to $8.6 million ($2009–10) for the next regulatory control period, using the cash flow model in the separate PTRM, results in expenditure that reasonably reflects the capex criteria, including the capex objectives, and reflects 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.

This amount has been amortised over the weighted average standard life of ETSA Utilities' RAB for the purposes of providing the equity raising cost allowance associated with the forecast capex over the next regulatory control period.[363]

Table 7.7: AER conclusion on ETSA Utilities' benchmark equity raising cost ($m, nominal)

Cash flow analysis	AER final decision (total)	Notes
Dividends	628.3	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	188.5	30% of dividends paid
Cost of dividend reinvestment plans	1.9	Dividends reinvested multiplied by benchmark cost (1%)
Capex funding requirement	1678.8	This is the forecast capex funding requirement (not the capex value that includes a half year WACC adjustment)
Debt component	670.9	Set to equal 60% of RAB increase (not capex)
Equity component	1007.9	Residual of capex funding requirement and debt component
Retained cash flows available for reinvestment	761.8	Includes dividends reinvested
External equity requirement	246.1	Equal to equity component less retained cash flows
External equity raising cost	7.4	External equity requirement multiplied by benchmark direct cost (3%)
Total equity raising cost	9.3	Sum of dividend reinvestment plan cost and external equity raising cost
Total equity raising cost ($2009–10)	8.6	To be added to the RAB at the start of the next regulatory control period

363 A standard life of 52.3 years for amortisation purposes, consistent with ETSA Utilities' weighted average asset life, has been applied.

7.4.8 Other issues raised in submissions

Underutilisation of demand management

The AER has addressed submissions relating to demand management in chapter 14 of this decision.

Demand driven capex

The AER notes that ECCSA queried the extent to which the AER had undertaken analytical work to review ETSA Utilities' claim for growth capex, on the basis of its own analysis suggesting the costs of accounting for growth accepted by the AER in its draft decision are expected to triple in the next regulatory control period.[364]

The AER has reviewed ECCSA's analysis of the anticipated cost of new customer connections ($26 000 per customer) is based on total gross demand driven capex divided by the expected growth in total customer numbers.[365] The AER does not consider that this analysis provides a realistic assessment of the cost of new customer connections given it accounts for the capacity related component of demand driven capex, which is not necessarily driven by customer connections, as well as the customer connection component. ECCSA's analysis also does not account for the total number of new customer connections expected in the next regulatory control period.

Based on the AER's analysis of ETSA Utilities' revised regulatory proposal, a more appropriate figure for expected net connection costs per customer in the next regulatory control period is approximately $2460 ($2009–10).[366] This compares to the equivalent figure for the current regulatory control period of $2570 ($2009–10). The AER therefore does not accept ECCSA's assertion that it has allowed for a tripling of per customer connection costs in the next regulatory control period.

The AER does not consider that ECCSA's analysis of the 'cost per MW in increased peak demand'[367] is meaningful given the costs included in ETSA Utilities' capacity capex proposal do not necessarily relate to changes in total system peak demand. For example, the $95 million City West transmission connection point project is included in the proposed capacity capex, but the need for the project is driven by mandated CBD network security requirements, not the need to accommodate a given increase in peak demand.

Kangaroo Island security of supply project

The submission from the SA Energy Minister and the KI joint parties questioned the AER's decision to reject the proposed second undersea cable for Kangaroo Island on

364 ECCSA, *A response*, February 2010, pp. 15-16.
365 ECCSA, *A response*, February 2010, p. 16.
366 Calculation based on total net customer connection capex of $147.9 million as shown on p. 109 of the revised regulatory proposal and total forecast new customer connections of 60 049.
367 ECCSA, *A response*, February 2010, p. 16.

the basis that the project was wrongly characterised as a security of supply project rather than to provide for demand growth.[368]

It should be noted however that the project was proposed by ETSA Utilities on the basis of security of supply considerations. The draft decision deferred the project to a timeframe when the project is justified by the need for capacity augmentation as the lowest cost solution. In addition, the AER notes that ETSA Utilities did not propose the Kangaroo Island security of supply project as part of its revised capex proposal for the next regulatory control period.[369]

Accordingly, the AER does not consider that an adjustment to ETSA Utilities' revised regulatory proposal to include additional capex for the Kangaroo Island project in the next regulatory control period is justified.

Non–system capex

The AER notes the comments of the EUAA regarding the AER's draft decision on the efficiency of proposed non–system capex.[370] The AER notes that its review of proposed non–system capex, and that of PB, was conducted on the same basis as the reviews of other elements of ETSA Utilities' capex proposal. This included reviews of a range of supporting documents provided by ETSA Utilities, including cost estimating models, business cases, plans, policies, procedures and strategies which, in the view of PB and the AER, supported the need, timing and efficiency of the proposed expenditures.[371] The AER considers that no new information has been provided to change the AER's view of the prudence and efficiency of the proposed non–system capex.

Benchmarking

The AER has addressed submissions relating to the AER's use of benchmarking in appendix I of this decision.

AER assessment methodology

The EUAA considers 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.[372]

As the EUAA recognises in its submission, it is not possible for the AER to undertake a detailed review of every 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, including in terms of capex policies and procedures, governance frameworks, key assumptions, input costs, demand forecasts and real cost escalators in determining whether it is satisfied the forecast capex

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368 KI joint submission, *AER draft distribution determination for ETSA Utilities*, February 2010, p. 2; and SA Energy Minister, *Submission*, 15 February 2010, p. 1.
369 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 82.
370 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 18–21.
371 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 168–171.
372 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 15–17.

reasonably reflects the capex criteria listed in clause 6.5.7(c) of the NER.[373] In that context, consideration of network businesses' processes, procedures and governance frameworks forms only a part of the AER's assessment.

Regarding the EUAA's query as to the meaning of the term 'good electricity industry practice' as used by the AER's engineering consultant, the AER notes that this term has the meaning set out in Chapter 10 of the NER. The AER agrees with the EUAA that the notions of 'efficiency' and 'good electricity industry practice' are not the same. The AER does, however, consider whether a DNSP's policies and practices are in accordance with good electricity industry practice to be a relevant consideration when assessing the prudence and efficiency of costs determined on the basis of those policies and practices.

Deliverability

ECCSA raised a number of concerns with regard to the deliverability of ETSA Utilities' proposed capex program. Specifically, ECCSA considered that EMS's review of deliverability was limited because it focused on staffing needs and ETSA Utilities' historical approach to resourcing and did not take account of ETSA Utilities' opex program or expenditure by DNSPs in other states. ECCSA also stated that the AER had failed to address concerns of whether the cost and timing of these capex projects are efficient and that ETSA Utilities will face competition for funding.[374]

In response to the concerns raised by ECCSA, the AER engaged EMS to provide an updated review of ETSA Utilities' capex deliverability. The AER notes EMS considered labour market conditions in South Australia and nationally, including requirements for capex and opex, and the effect of current and potential capex expansions across regulated network businesses in several states.[375] As a result of the scope of EMS's considerations, the AER is satisfied that EMS adequately addressed ECCSA's concern that capex labour requirements were considered in isolation.

The AER notes that EMS considered ETSA Utilities will face pressures in meeting its labour requirements, particularly in terms of technical skilled workers. However, the AER also notes that EMS considers ETSA Utilities has favourable prospects for inter-state and international recruitment if this is necessary.[376]

The AER notes that ECCSA indicated concern that the EMS report was limited by its focus on staffing needs and historical staffing processes.[377] The AER notes that EMS also considered the deliverability constraints of input material requirements. EMS concluded that, although there will be significant pressure on the supply of materials and equipment during the next regulatory control period, ETSA Utilities is well positioned to deal with these pressures as a result of strong procurement processes.[378]

Having considered ECCSA's submission, ETSA Utilities' revised regulatory proposal and EMS' advice, the AER considers that ETSA Utilities' capex proposal will be

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373 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 100–101.
374 ECCSA, *A response*, February 2010, pp. 18–19.
375 EMS, *Reassessment of deliverability*, March 2010, p. 19.
376 EMS, *Reassessment of deliverability*, March 2010, p. 36.
377 ECCSA, *A response*, February 2010, p. 17.
378 EMS, *Reassessment of deliverability*, March 2010, p. 36.

deliverable.[379] Further, the AER is satisfied that EMS has adequately addressed the concerns raised by ECCSA in relation to capex deliverability.

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's assessment was not based on an independent and critical assessment.

As described in PB's report on ETSA Utilities' proposal, and in the draft decision, PB's high-level analysis did not identify any issues in relation to ETSA Utilities' unit costs that PB considered warranted further investigation.[380] 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.

7.5 AER conclusion

The AER has reviewed ETSA Utilities' proposed forecast capex allowance and, for the reasons set out in this chapter, the AER is not satisfied that the proposed forecast capex allowance reasonably reflects the capex criteria under clause 6.5.7(c) of the NER. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the NER. Following its review of ETSA Utilities' revised capex proposal, the AER has made the following adjustments:

- $39 million reduction to the low voltage capacity upgrade program to reflect a revised scope for required transformer augmentations
- $93 million reduction to asset replacement capex to reflect amended forecasting methodologies and a revised scope across a number of expenditure categories
- $2 million reduction to security of supply capex to reflect the exclusion of inefficient expenditure from the network control project
- $6 million reduction to safety capex to reflect a revised scope for the substation security and fencing program
- $6 million reduction to customer connection capex to reflect the exclusion of proposed costs associated with the revised negotiating framework for negotiated distribution services
- $43 million reduction to reflect the application of amended input cost escalators.

As the AER is not satisfied that the capex allowance proposed by ETSA Utilities reasonably reflects the capex criteria, under clause 6.5.7(d) of the NER the AER must not accept the forecast capex proposed by ETSA Utilities. Under clause 6.12.1(3)(ii) of the NER, the AER is required to provide an estimate of the capex for ETSA

[379] EMS, *Reassessment of deliverability*, March 2010, p. 37.
[380] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 119–120.

Utilities over the next regulatory control period which it is satisfied reasonably reflects the capex criteria, taking into account the capex factors.

The AER considers the adjustments listed above are the minimum necessary to ensure ETSA Utilities' capex forecast reasonably reflects the capex criteria. Allowing for these adjustments, the AER's estimate of forecast net capex for ETSA Utilities is $1588 million, as set out in table 7.8. The AER notes the reduction in total allowed net capex compared to the draft decision is driven by changes in input cost escalation rather than additional reductions to the scope of the capex work program.

Table 7.8: AER conclusion on ETSA Utilities' forecast capex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities revised proposed net capex[a]	337.0	392.9	351.8	350.1	345.6	1777.3
Adjustment to demand driven capex	–7.7	–7.9	–7.9	–7.9	–7.9	–39.3
Adjustment to asset replacement capex	–15.8	–20.4	–18.9	–19.0	–18.4	–92.5
Adjustment to security of supply capex	–2.4	–	–	–	–	–2.4
Adjustment to safety capex	–2.3	–2.6	–1.0	–0.6	0.1	–6.4
Adjustment to customer connection capex	–1.2	–1.2	–1.2	–1.3	–1.3	–6.3
Adjustment to cost escalators	–6.1	–13.1	–10.0	–7.7	–6.0	–42.8
AER capex allowance	301.4	347.7	312.9	313.6	312.1	1587.7

Notes: Totals may not add due to rounding.
(a) Excludes proposed equity raising costs. The AER will allow ETSA Utilities to amortise a total amount of $8.6 million ($2009–10) in benchmark equity raising costs for the next regulatory control period.

7.6 AER decision

In accordance with clause 6.12.1(3)(ii) of the NER, the AER does not accept ETSA Utilities' forecast capex for the next regulatory control period. The AER is not satisfied that ETSA Utilities' forecast capex, taking into account the capex factors, reasonably reflects the capex criteria in clause 6.5.7 of the NER.

The AER's estimate of the total capex required by ETSA Utilities in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, is set out in table 7.8 of this decision.

The AER's reasons for this decision are set out in section 7.4 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 ETSA Utilities. It also sets out the AER's conclusion on ETSA Utilities' forecast opex for the next regulatory control period.

The opex forecasts in ETSA Utilities' revised regulatory proposal are based on its 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

The AER considered ETSA Utilities' forecast opex and was not satisfied that the total opex forecast proposed by ETSA Utilities reasonably reflected the opex criteria, including the opex objectives, in clause 6.5.6 of the NER. In coming to this view the AER had regard to the opex factors. In establishing the opex allowance the AER made the following adjustments:[381]

- $0.3 million reduction to maintenance and repair opex
- $5.0 million reduction to reflect a revised network growth escalator
- $0.01 million reduction to reflect revised network access, monitoring and control opex to remove the impact of the growth in work volume or network growth
- $20 million reduction to maintenance and repair and emergency response opex
- $4.8 million reduction to vegetation management
- $11 million reduction to emergency response opex
- $3.3 million reduction to sponsorships and community engagement projects
- $1.6 million reduction to reflect adjusted workload escalator
- $38 million reduction to reflect revised real input cost escalators
- $33 million reduction to the forecast self insurance opex
- $14 million reduction to the forecast for debt raising costs.

Based on its analysis of ETSA Utilities' regulatory proposal, the advice of PB and other information, the AER applied a reduction of $131 million (11 per cent) to ETSA Utilities' forecast opex. This resulted in a revised opex allowance of $1044 million ($2009–10). The AER considered this reduction was the minimum adjustment

[381] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 244.

necessary to ensure ETSA Utilities' opex forecast met the opex criteria. The AER's conclusion on ETSA Utilities' opex by category is in table 8.1.

Table 8.1: AER draft conclusion on ETSA Utilities' total opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities forecast opex	210.0	222.7	234.5	248.8	259.2	1175.0
Adjustments to controllable opex	–4.3	–6.5	–8.6	–10.9	–13.5	–43.9
Adjustments to self insurance	–6.4	–6.5	–6.7	–6.8	–6.9	–33.2
Adjustment to debt raising costs	–2.7	–2.7	–2.8	–3.0	–3.1	–14.3
Adjustment to input cost escalators	–2.7	–5.5	–8.0	–9.9	–12.0	–38.0
Adjustment for workload escalator recalculated for adjusted capex and opex	–0.2	–0.3	–0.4	–0.3	–0.3	–1.6
Total AER approved opex allowance	193.7	201.2	208.0	217.9	223.4	1044.0

Source: AER, *Draft decision, SA draft distribution determination*, November 2009, p. 245.

8.2 Revised regulatory proposal

ETSA Utilities did not accept the AER's conclusion on opex, and included an opex forecast of $1082 million ($2009–10) in its revised regulatory proposal. This is $38 million ($2009–10) higher than the total opex approved by the AER in its draft decision.

ETSA Utilities proposed adjustments to the draft decision relating to:[382]

- escalation of emergency response opex
- trade–off for asset replacement
- asset age escalation
- network growth escalation
- self insurance
- debt-raising costs

[382] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 113.

- feed–in tariffs
- input cost escalators, including network growth escalation.

ETSA Utilities' revised forecast opex allowance for the next regulatory control period is set out in table 8.2.

Table 8.2: ETSA Utilities' revised forecast opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Controllable opex						
Network operating opex	28.2	28.6	29.1	29.8	30.6	146.3
Network maintenance	78.3	80.2	83.2	87.1	89.5	418.3
Customer services	21.3	21.8	22.3	22.8	23.5	111.7
Allocated opex	48.4	51.8	54.0	58.0	59.0	271.2
Total controllable opex	176.2	182.4	188.6	197.7	202.6	947.5
Uncontrollable opex						
Superannuation	9.8	9.9	10.0	10.2	10.4	50.3
Self insurance	3.0	3.2	3.3	3.5	3.8	16.8
Feed–in tariffs	7.0	8.7	10.1	11.1	11.7	48.6
Debt raising costs	3.5	3.6	3.7	3.8	3.9	18.5
Total uncontrollable opex	23.2	25.3	27.2	28.6	29.8	134.2
Total opex forecast	199.5	207.7	215.8	226.4	232.3	1081.7

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 135.
Note: Totals may not add due to rounding.

ETSA Utilities maintained the opex forecasting methodology which involved applying the following four stage process:

- defining an efficient base year (2008–09)
- where applicable, adjusting the opex incurred in the base year to account for changes in scope (activities carried out in delivery of standard control services)
- applying scale escalation (changes in the volume of existing activities carried out by ETSA Utilities) to each opex category, depending on the drivers that impact upon each category. ETSA Utilities identified four scale escalators– network growth, work volume, workforce size and customer growth
- applying input cost escalators, reflecting real increases in the cost of labour, materials and services, to each opex category.

8.3 Submissions

The Energy Consumers Coalition of South Australia (ECCSA) and the Energy Users Association of Australia (EUAA) provided submissions relating to the draft decision.

ECCSA was concerned about:

- underspend of regulated opex allowance in the current regulatory control period[383]
- escalation factors including network growth, work volume, workforce size and customer growth[384]
- the inclusion of real electricity, gas and water sector wages[385]
- the increase in capex should reduce ETSA Utilities' opex because of capex/opex trade offs, productivity savings and savings from maintenance programs no longer required on replaced assets[386]
- the treatment of related business services.[387]

The EUAA was concerned about:

- misplaced reliance on processes and governance procedures[388]
- use of a base year to develop the opex forecast[389]
- benchmarking[390]
- debt and equity raising costs.[391]

8.4 Issues and AER considerations

8.4.1 Escalation of emergency response activities

AER draft decision

The AER did not accept ETSA Utilities' proposal to apply its proposed economies of scale escalation for network growth to its opex allowance in relation to emergency response activities. The AER considered that a significant proportion of the emergency response activities were driven by asset failure arising from poor condition or maintenance, rather than from external factors such as weather related damage. The AER considered that in such circumstances, asset replacement capex and maintenance

[383] ECCSA, *A response*, February 2010, pp. 25–26.
[384] ECCSA, *A response*, February 2010, pp. 33–36.
[385] ECCSA, *A response*, February 2010, pp. 31–33.
[386] ECCSA, *A response*, February 2010, p. 36.
[387] ECCSA, *A response*, February 2010, p. 31.
[388] EUAA, *Submission to the AER on ETSA Utilities*, February 2010, p. 23.
[389] EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 24–25.
[390] EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 29–30.
[391] EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 30.

and repair should directly reduce the level of emergency response opex, as the new or refurbished and maintained assets are considerably less likely to fail.[392]

Accordingly, the AER reduced the economies of scale factor for emergency response opex, resulting in a reduction of $10.9 million ($2009–10) to forecast opex for the next regulatory control period.[393]

Revised regulatory proposal

ETSA Utilities did not agree with the draft decision to reduce the economies of scale factor for emergency response opex.[394]

ETSA Utilities stated its escalation of emergency response opex involves taking the defect ratio that currently applies to its network assets, and applying this ratio to an enlarged network in the future. It noted that embedded within the current defect ratio is a mix of new and aged assets—assets which exhibit certain 'infant mortality' failure rates, and other age, condition, and environmental failure rates. ETSA Utilities stated it conservatively applied an economies of scale factor of 5 per cent to the defect ratio for the next regulatory control period, recognising that advances in production processes and operating methods may have a marginally favourable impact on failure rates during the next regulatory control period.[395]

ETSA Utilities’ stated the AER applied similar arguments to those used in its transmission determinations for Powerlink and TransGrid on the treatment of defect maintenance opex. ETSA Utilities noted that TransGrid ultimately applied to the Australian Competition Tribunal (the Tribunal) for a review of this aspect of the AER’s decision and the Tribunal set aside the AER’s decision. ETSA Utilities considered its proposed economies of scale factor is consistent with the Tribunal decision.[396]

Consultant review

Asset age

PB noted that ETSA Utilities applied an additional variation to its emergency response opex associated with an increase in average asset age. PB considered this variation accounts for an increase in defect rates as the weighted average age of the network increases during the next regulatory control period. PB stated that it is through this mechanism that ETSA Utilities has established the relationship between asset age, defects and associated opex.[397]

However, PB considered ETSA Utilities had not presented any detailed description or discussion of the nature and basis of the current regulatory control period defect ratios, which impact on levels of unplanned emergency response activities. PB also noted the significant variation (increasing and decreasing) in ETSA Utilities’ weighted average ages across various asset categories. It considered further

392 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 214–215.
393 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 244.
394 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 120.
395 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 120.
396 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 120.
397 PB, *Review of ETSA Utilities’ revised regulatory proposal*, April 2010, p. 28.

information is needed to substantiate the impact of average asset age variation on emergency response opex at an asset category level.[398]

PB considered the impact of the aging asset base is captured in the Sinclair Knight Merz (SKM) modelling and its application to asset age escalation. This is discussed in section 8.4.3 of this decision.[399]

TransGrid transmission determination

PB highlighted the following key differences to the opex modelling undertaken by ETSA Utilities and TransGrid:[400]

- ETSA Utilities separated non-routine 'defect maintenance' into 'repairs' and 'emergency response' opex, whereas TransGrid grouped all these elements together

- Unlike TransGrid, ETSA Utilities did not develop or apply any defect ratios based on historically averaged costs across asset classes.

PB considered that non-routine defect repairs for new assets, as well as the emergency response opex associated with external influences should not be amended. However, PB stated that the component of emergency response opex associated with plant condition and performance should be excluded from the forecast as new growth assets are not likely to suffer such failures within the timeframes of the next regulatory control period. PB stated it has not recommended excluding defect maintenance from ETSA Utilities' opex forecast.[401]

PB also noted although it has recommended reducing the increase in defect maintenance with respect to new assets incorporated into the emergency response opex forecast, it had not excluded it entirely. PB noted that the reduction in emergency response opex for new growth assets reflects the historical expenditure attributed to equipment failure.[402]

PB also responded to ETSA Utilities' forecasting methodology of taking the defect ratio that currently applies to its network assets and applying this ratio to its expanded network in the future. PB stated that it accepted the basis of this forecasting methodology because embedded within the current defect ratio is a mix of new and aged assets which exhibit certain 'infant mortality' failure rates, and other age, condition and environmental failure rates.[403] PB made these comments in response to ETSA Utilities' claim the Tribunal found that the AER was wrong to assume that the existing pool of ageing assets, that is assets other than the new growth assets, would have the same level of defects as in the base period.

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[398] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 28.
[399] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 28.
[400] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 28.
[401] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 28.
[402] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 27–28.
[403] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 27.

Conclusion

Given the specific differences between the opex modelling approaches of ETSA Utilities and TransGrid PB confirmed its recommendation to reduce the economies of scale factor applied to the network growth escalator for emergency response opex. PB recommended a reduction in the economies of scale factor of 43 per cent, or from 0.95 to 0.54, and estimated this would reduce ETSA Utilities' emergency response opex by $8.7 million in the next regulatory control period.[404]

AER considerations

The AER notes ETSA Utilities has characterised its forecast emergency response opex as being developed by applying a defect ratio that is derived from its current network assets to its enlarged network. However, the defect ratio used by ETSA Utilities is not based on actual historical costs averaged across asset classes. ETSA Utilities increased its emergency response opex in response to an increase in the average asset age of its network, which encompasses an increase in defect rates based on an increase in the weighted average age of the network during the next regulatory control period. It is through this mechanism that ETSA Utilities has endeavoured to establish the relationship between asset age, defects and associated opex.

Average asset age

The AER notes ETSA Utilities claim that the new assets to be installed during the next regulatory control period will not reduce the average age of ETSA Utilities' network as compared to the 2008–09 base year. However, the AER also notes asset age is separately factored into ETSA Utilities' opex forecasts by the application of the asset age escalator, as discussed in section 8.4.3.

The AER considers that the impact of the average age of ETSA Utilities' network is appropriately taken into account by the asset age escalation factor, and does not need to be further factored into the consideration of the emergency response opex.

TransGrid transmission determination

The AER notes ETSA Utilities relied on the Tribunal decision regarding the TransGrid transmission determination to refute the adjustment applied in the draft decision. However, the AER considers there are a number of differences between the recommendation implemented and overturned by the Tribunal in the TransGrid transmission determination and ETSA Utilities' regulatory proposal.

In the TransGrid transmission determination defect repair and emergency repair opex for all new growth assets was excluded from the opex forecast. In light of the Tribunal decision, the AER does not consider it reasonable to exclude all defect maintenance costs for new assets and recognises that new assets are subject to failure due to third party, external and environmental factors.

The draft decision did not exclude all emergency response opex on new assets, rather it applied a reduction in the growth of emergency response opex to better account for the expected reduction in defect maintenance of new assets due to asset condition or age.

[404] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, pp. 28–29.

The AER has reviewed the Tribunal's decision of the TransGrid transmission determination and notes the Tribunal's comments in regard to average defect rates. The Tribunal stated:[405]

> In accepting PB's advice that as TransGrid's opex model uses system average ages to forecast opex, it tends to overstate the defect rectification expenditures required for new assets, the AER is saying it is wrong to apply an average rate of defects to new assets, because that overstates the defect level of new assets. But that is not what TransGrid is doing. TransGrid is not applying average defect rates to new assets. TransGrid is applying average defect rates to the whole system and it therefore applies them to the old assets, (which have higher levels of defects), the mid-life assets, (which have medium levels of defects) and the new assets, (which have a level, albeit contested, of defects). By removing one element to which the averaging is applied, the AER destroys the integrity of the averaging system as a whole.

The AER considers that there are significant differences in the circumstances and network characteristics underlying the opex modelling approaches adopted by TransGrid and ETSA Utilities, in particular:

- the AER understands that TransGrid increased its base year routine maintenance costs by its network growth scale escalator and then applied its historical average defect ratio (developed across five key asset classes) to inform the defect maintenance forecasts. The AER's determination for TransGrid removed defect maintenance (non-routine defect repairs and emergency repairs) for all growth assets from the opex allowance. This is incontrast to ETSA Utilities' approach which separated out non-routine 'defect maintenance' into 'repairs' and 'emergency response' opex rather than being grouped together in the case of TransGrid. ETSA Utilities did not develop or apply defect ratios based on historically averaged costs across asset classes. In the case of ETSA Utilities, the AER has accepted that non-routine defect repairs for new assets are still included in addition to the emergency response opex associated with external influences.

- the AER understands that the Tribunal's comments were made in the context that the weighted average network age for TransGrid's key asset classes remained relatively stable between regulatory control periods. This contrasts with ETSA Utilities, where PB has advised that there is significant variation in the forecast ages across asset classes, where some have increased by 3.8 years while others have decreased by 4.5 years. The AER considers that the significant change in weighted average ages across many of its asset classes limits the ability of the averaging effect to inform the impact of ETSA Utilities' asset replacement.

- the approach adopted by TransGrid involved transparent presentation of actual defect ratios over an extended historical period, whereas ETSA Utilities did not provide any similar information to verify the trends in defect ratios related to emergency response opex.

On the basis of these differences between TransGrid and ETSA Utilities in modelling approaches for emergency response opex, the AER considers its approach to adjusting

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405 Australian Competition Tribunal, *Application by Energy Australia and Others [2009] ACompT 8*, paragraph 307.

ETSA Utilities' proposed emergency response opex (by reducing the economies of scale factor applied to the network growth escalator) is reasonable.

Overstatement of emergency repair opex

Given that asset age is factored into ETSA Utilities' modelling, and that the AER has recognised that the emergency repair costs will be incurred in respect of new assets, the AER has considered the specific amount of emergency response opex required by ETSA Utilities. In doing so the AER has considered PB's report and recommended adjustments. The adjustments are recommended to address the impact of new assets on the requirement for emergency response opex. The AER considers that new assets should reduce the need for emergency response opex as they are less likely to fail (due to condition) and will often be able to be repaired under warranty.

The AER considers it reasonable that the network growth escalator for emergency response opex be reduced by 43 per cent (which represents the proportion of ETSA Utilities' historical emergency response opex arising due to equipment failure) to account for the expectation that new assets are not likely to fail consistently and repeatedly in an unplanned manner, but are expected to be exposed to external factors. The AER also considers that PB's analysis has isolated the impact of new growth assets on emergency response opex from the forecast increase in the average age of ETSA Utilities' network during the next regulatory control period. The impact of this is captured by ETSA Utilities' network asset age escalators and is discussed in section 8.4.4 of this decision.

The AER is satisfied that the opex modelling approach adopted by ETSA Utilities, and the methodology adopted by PB to determine the proportion by which to reduce ETSA Utilities' forecast increase in emergency response opex, are sufficiently different to the modelling approach adopted by TransGrid. Accordingly, the AER considers that the approach it has adopted does not, contrary to ETSA Utlities' assertion, fall into the same error that was found by the Tribunal in respect of the AER's treatment of defect maintenance for TransGrid.

AER conclusion

The AER requested ETSA Utilities model the impact of the AER's decision on emergency response opex. ETSA Utilities advised that the adjustment to forecast emergency response opex is a reduction of $7.2 million ($2009–10).[406]

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, PB's reports and other material, the AER is not satisfied that ETSA Utilities' forecast emergency response opex results in expenditure that reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing ETSA Utilities' proposed emergency response costs by $7.2 million ($2009–10) results in expenditure that reasonably reflects the opex criteria, including the opex objectives and is the minimum adjustment necessary for this opex component to comply with the NER. In coming to this view the AER has had regard to the opex factors.

[406] ETSA Utilities, email response to AER, 14 April 2010.

8.4.2 Trade off for asset replacement

AER draft decision

The AER did not accept ETSA Utilities' capex/opex trade off proposal in relation to asset replacement activities. The AER considered that ETSA Utilities did not adequately model the expected capex/opex trade off, and included a substitute trade off estimate in the forecast opex modelling.[407]

This adjustment resulted in a reduction of $0.3 million ($2009–10) to the forecast controllable opex for the next regulatory control period.[408]

Revised regulatory proposal

ETSA Utilities did not agree with the draft decision to reduce opex by $0.3 million to account for the asset replacement capex trade off.[409] ETSA Utilities' claimed that the modelling used in the draft decision did not incorporate the following opex factors in relation to increasing asset replacement spending:[410]

- an increasing average network age
- a larger proportion of ageing assets to be operated and maintained relative to the newer asset base resulting from the asset replacement capex program.

ETSA Utilities argued that these factors override the savings in opex that would occur as asset replacement capex takes place.[411]

ETSA Utilities also claimed that the top-down financial ratio methodology used in the draft decision was an oversimplification of the capex/opex trade off relationship and is unsuitable for the application proposed by the AER. ETSA Utilities rejected the appropriateness of the '20 per cent factor' applied by PB in the top-down financial ratio analysis on the basis that it was a gross generalisation. ETSA Utilities provided a report from SKM supporting its claim. ETSA Utilities further claimed that the reasons provided in the draft decision as to why ETSA Utilities' method of evaluating the opex trade off was unsuitable were inconsequential and invalid reasons to dismiss ETSA Utilities' methodology. The reasons noted by ETSA Utilities included that ETSA Utilities is increasing its replacement capital expenditure and that ETSA Utilities is recommending removal of the age escalation applied to maintenance and repair and emergency response opex.[412]

Consultant review

PB stated that a desensitised application of the SKM[413] age-opex relationships and modelling is appropriate, as discussed in section 8.4.3 of this decision. PB stated that the SKM modelling approach implicitly incorporates a suitable replacement

407 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 195–196.
408 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 195–196.
409 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 123.
410 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 122.
411 ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 122–123.
412 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 122.
413 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 127.

capex/opex trade off and reflects a preferred and more accurate approach compared with that used in the draft decision. PB argued that this is because the model assumes that the oldest assets in each category are replaced first, based on the accepted replacement capex program.[414]

PB also stated that it is satisfied that the reservations it expressed in regards to the application of the SKM model have been addressed through the adjustments incorporated by ETSA Utilities.[415]

AER considerations

After consideration of the report by SKM, PB's analysis and the revisions incorporated into the age/opex modelling, the AER does not consider any further adjustment to ETSA Utilities' opex to account for capex/opex trade off is required.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, PB's reports and other information, the AER is satisfied ETSA Utilities' modelling of capex/opex trade off results in expenditure that reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

8.4.3 Asset age escalation

AER draft decision

ETSA Utilities argued that the deteriorating age and condition profile of its distribution network will lead to an increase in the opex that it will incur during the next regulatory control period.[416] ETSA Utilities identified the two opex categories, maintenance and repair and emergency response, as being impacted by the increase in the age of its assets during the next regulatory control period.[417] An increase in the age of ETSA Utilities' assets during the next regulatory control period is not in itself one of the four scale escalation factors ETSA Utilities developed to forecast its opex allowance for the next regulatory control period. The AER did not accept ETSA Utilities' proposal to increase maintenance and repair and emergency response opex associated with asset age escalation.

The AER considered that the impact of ETSA Utilities' increasing asset age was overstated in ETSA Utilities' modelling.[418] The AER considered that ETSA Utilities had not appropriately modelled the likely impact of asset age on its opex forecast, as it did not accurately calibrate the opex/age curves in its modelling.[419]

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414 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 38.
415 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 38.
416 ETSA Utilities, *Revised regulatory proposal*, July 2009, p. 158.
417 ETSA Utilities, *Revised regulatory proposal*, July 2009, p. 159.
418 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 205.
419 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 195.

This adjustment resulted in a reduction of $19.5 million ($2009–10) to the maintenance and repair and emergency response forecast controllable opex for the next regulatory control period.[420]

Revised regulatory proposal

In accordance with the draft decision, ETSA Utilities made two adjustments to its asset age escalation model, limiting the application of SKM's age escalators to:[421]

- 86 per cent of its network maintenance and repair opex, thereby removing any age escalation that could be attributable to poles

- 43 per cent of emergency response opex, thereby eliminating any escalation that could be attributable to causes other than equipment failure.

ETSA Utilities also reported that it requested SKM to model the impact of both of the AER's proposed adjustments in its draft decision, as well as the capex proposed in ETSA Utilities' revised regulatory proposal, on the age profile of its assets. As a result of this revised modelling, ETSA Utilities stated that errors were identified which overstated the asset age escalators. On the basis of SKM's revised modelling, ETSA Utilities proposed an increase of $6.7 million ($2009–10) to the total forecast opex in the draft decision.[422]

Consultant review

PB considered SKM's network asset age model to be a sound framework and recommended that the AER accept the application of the revised model. However, PB noted the escalation factor applying to emergency response opex should be determined by compounding the application of cumulative escalators to remove age related escalation of poles and any escalation that could be attributable to causes other than equipment failure in the emergency response activity.[423]

PB stated that the impact of the corrected SKM model used by ETSA Utilities to measure the effect on maintenance and repair and emergency response opex associated with asset ageing escalation is an increase in total opex of $7.0 million.[424]

PB further considered that although SKM's network asset age model was a sound framework, PB was not satisfied that ETSA Utilities had substantiated the application of a 3.2 per cent opex age relationship. PB came to this view based on:[425]

- the contribution of the overhead fittings asset class to ETSA Utilities' asset base (54 per cent of value) and the estimated increase of 3.9 years for this asset class in the next regulatory control period –many of the assets in this category, in particular insulators, for which the weighted average age for these assets will only be 42 years at the end of the next regulatory control period are not expected to

[420] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 244.
[421] ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 127.
[422] ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 127.
[423] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 35.
[424] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 35.
[425] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 36.

experience any wear out characteristics until they are at least 66 years of age (a difference of 57 per cent). PB also stated that it did not have a detailed understanding of the condition of the overhead asset class, in particular crossarms, or their potential onset of wear out

- the calibration of SKM's model with reference to Powercor's network in Victoria, which has a predominance of wooden poles and crossarms

- ETSA Utilities not being able to provide supporting information in its original proposal

- PB's experience that the real annual growth in maintenance and repair and emergency response related opex in excess of PB's expected range of 1.5 to 3.0 per cent should be able to be well supported by reference to actual experience, changes in asset management practices and actions that are well understood.

On the basis that there will only be a small increase in opex due to the ageing of the overhead asset class during the next regulatory control period, PB recommended that SKM's model be desensitised to the opex–age relationship by 50 per cent.[426] PB further considered that applying a constant adjustment of 50 per cent to all asset classes maintains the integrity of the weightings based application of the model and effectively results in a direct reduction of 50 per cent in the final opex age escalators produced.[427]

Based on its application of the corrected SKM model which provided an asset age escalation of $7.0 million, and the application of de-sensitised age related escalators of 50 per cent, PB recommended a positive adjustment of approximately $3.5 million to ETSA Utilities' opex from the draft decision. PB noted that if there was no change to the draft decision on the replacement capex allowance for ETSA Utilities, the change in the age-related escalators will result in an associated scaling of opex from $3.5m to $3.9m based on the recommended model and inputs and the implicit capex/opex trade-off.[428] The reduced capex allowance provided in the draft decision compared to ETSA Utilities'original regulatory proposal increases the age-related escalators recommended by PB from $3.5 to $3.9 million.[429]

AER considerations

The AER considers the revised asset age escalation model developed by SKM is an appropriate basis from which to derive asset age escalation factors for ETSA Utilities. The model has been subject to detailed review by PB, and has been revised to address concerns raised regarding the escalation of poles and emergency response opex, and other acknowledged errors.

The AER also considers that PB has substantiated its concerns regarding ETSA Utilities' application of a 3.2 per cent opex age relationship and that ETSA Utilities' proposed opex age relationship should be reduced by 50 per cent.

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426 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 35.
427 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 36.
428 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 37.
429 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 37.

The AER notes that the draft decision on ETSA Utilities' replacement capex allowance has been substantially upheld in this decision (refer to section 7.5).

AER conclusion

The AER requested ETSA Utilities model the impact of asset age escalation on the AER's decision on maintenance and repair and emergency response opex. ETSA Utilities advised that the adjustment to forecast emergency response opex is a reduction of $3.3 million ($2009–10).[430]

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, PB's report and other material, the AER is not satisfied that ETSA Utilities' forecast maintenance and repair and emergency repair opex results in expenditure that reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing ETSA Utilities' proposed maintenance and repair and emergency repair opex 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.

8.4.4 Network growth escalation

AER draft decision

The AER did not accept ETSA Utilities' proposal to increase opex activities associated with network growth escalation. Network growth is one of four scale escalation factors identified by ETSA Utilities in developing its forecast opex allowance and refers to the growth in the size of its distribution network during the next regulatory control period. The AER considered that the network growth factor applied by ETSA Utilities was higher than necessary to reflect the efficient costs of a prudent operator. The AER considered that the network growth rate estimated by PB provided a reasonable basis for adjusting for the overestimation of costs arising from the application of ETSA Utilities' network growth escalator.[431]

This adjustment resulted in a reduction of $5.0 million ($2009–10) to the forecast controllable opex for the next regulatory control period.[432] [433]

Revised regulatory proposal

ETSA Utilities considered that the methodology used in the draft determination to calculate the network growth escalator required further refinement to take account of the relative weight of the asset classes comprising ETSA Utilities' network. ETSA

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430 ETSA Utilities, email response to AER, 14 April 2010.

431 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 214.

432 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 244.

433 Based on the modelling request advice provided by ETSA Utilities to the AER on 6 November 2009, the AER's draft decision provided for a reduction of $5.0 million to reflect the revised network growth escalator, which appears to be made in error. The AER notes that ETSA Utilities' revised proposal provides for a reduction of approximately $9.8 million to reflect the impact of the adjustment to the network growth escalator in the draft decision. This value is consistent with PB's recommended reduction to ETSA Utilities' proposed opex for the draft decision.

Utilities stated that by calculating a simple average of the three asset classes, PB applied equal weight to growth in the length of power lines, the number of distribution transformers and substation capacity. ETSA Utilities claimed that given the asset classes that underpin the growth in these three indicators represent substantially different proportions of its total network, it is more appropriate that a weighted average of the growth across the three indicators be used for the bottom-up calculation.[434]

ETSA Utilities calculated the weightings of the three asset classes using the capital values across the asset classes as set out in its Regulatory Financial Report for the year ended June 2008. ETSA Utilities reported that this has the effect of increasing the five year average network growth escalator from 2.72 per cent to 2.79 per cent and reducing the adjustment applied by the AER from $9.8 million to $6.3 million.[435]

Consultant review

PB considered that the weighted growth escalator proposed by ETSA Utilities is a reasonable refinement to the calculation of a bottom-up growth escalator as it accurately recognises the proportion of assets (by capital value) within each of the identified classes. PB also considered the approach adopted by ETSA Utilities in determining the weightings in each class is suitable and appropriate, and that on the basis of the detailed and transparent calculations in its revised regulatory proposal, the weighted average growth escalator has been applied correctly.[436]

AER considerations

The AER notes ETSA Utilities' concerns that the methodology used in the draft decision to calculate the network growth escalator requires further refinement and that the weighted average of growth assets are used for the bottom-up calculation. The AER considers the use of a weighted average will provide a stronger reflection of the proportion of future opex requirements compared with assuming equal weighting across the three asset classes

The AER notes PB considered the weighted growth escalator proposed by ETSA Utilities to be a reasonable refinement, ETSA Utilities' approach to determining the weightings in each class is appropriate and that the weighted average growth escalator has been applied correctly. The AER has also formed the view that the methodology used to calculate ETSA Utilities' network growth escalator should be modified to account for the weighted average of the relevant asset classes included in its calculation.

The AER accepts ETSA Utilities' revised regulatory proposal of a positive adjustment to the network growth escalator of $3.5 million.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, PB's reports and other information, the AER is

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[434] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 116.
[435] ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 116–118.
[436] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 40.

satisfied that ETSA Utilities' proposed network growth escalator results in forecast opex expenditure that reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

8.4.5 Self insurance

The AER applied a principled approach to assessing ETSA Utilities' self insurance proposal within the draft decision. By applying this approach, the AER rejected ETSA Utilities' proposed self insurance premiums. In particular the AER rejected ETSA Utilities' proposed self insurance allowances for property risks, poles and wires risks, motor vehicle risks and underground damage and environmental liability risks. The AER considered that the most appropriate self insurance premium for these risks was zero. Further, the AER rejected ETSA Utilities' $12.2 million public liability self insurance allowance and considered that the most appropriate premium was $422 per annum over the next regulatory control period.[437] The AER accepted ETSA Utilities' proposed worker's compensation self insurance premium.

Revised regulatory proposal

ETSA Utilities did not accept the AER's draft decision and resubmitted its original self insurance proposal of $36.0 million. ETSA Utilities disagreed with the draft decision regarding self insurance. In general, ETSA Utilities considered that the AER had misunderstood its self insurance proposal, stating that the AER did not understand that there were self insurance baseline costs included within the opex forecasts. ETSA Utilities considered that the opex forecasts were examined and assessed as being reasonable in chapter 8 of the draft decision, and thus the AER should only have been examining the variation costs in the self insurance appendix.[438] ETSA Utilities also stated that the AER did not understand that ETSA Utilities categorised costs associated with below deductible events can be forecast with certainty within the self insurance cost category. ETSA Utilities considered that the AER did not understand the types of events that are sought to be recovered as self insurance costs.[439]

AER considerations

The AER's detailed consideration of ETSA Utilities' revised regulatory proposal in relation to self insurance is set out in appendix H. The AER considered that its five principles that were used to assess ETSA Utilities' self insurance proposal in the draft decision should be augmented by a further consideration. The further consideration, in accordance with the EBSS, is that a self insurance cost should not be a 'business as usual cost' or 'an ongoing business activity'. This resulted in several self insurance risk categories being reclassified as controllable opex, and being rejected as self insurance.

AER conclusion

For the reasons discussed and as a result of its consideration of ETSA Utilities revised regulatory proposal and other material, the AER is not satisfied that the proposed self insurance allowance reasonably reflects the opex criteria, including the opex

437 AER, *Draft decision, SA draft distribution determination*, November 2009, appendix K.

438 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, Detailed response – self insurance, pp. 1, 11.

439 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 1.

objectives. The AER considers that reducing ETSA Utilities' proposed self insurance opex by $29.9 million results in expenditure that reasonably reflects the opex criteria, including the opex objectives, and is the minimum adjustment necessary for this opex component to comply with the NER. This reduction includes the reclassification of $21.6 million of 'business as usual costs' to controllable opex. In coming to this view the AER has had regard to the opex factors and the self insurance principles outlined in appendix H.

Table 8.3 summarises the proposed self insurance allowances and the AER's draft decision.

Table 8.3: AER conclusion on ETSA Utilities' self insurance allowances ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities proposed	6.9	7.1	7.2	7.3	7.5	36.0
AER adjustments	1.5	1.6	1.7	1.7	1.8	8.3
Proposed self insurance events reclassified as controllable opex	4.3	4.3	4.3	4.3	4.4	21.6
Total self insurance	1.2	1.2	1.2	1.2	1.3	6.1

Note: Totals may not add due to rounding.

8.4.6 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 data from 2007–08.[440] This analysis was informed by benchmarking work that has been undertaken by Ofgem in the United Kingdom, and by Wilson Cook for the AER.[441] The AER also considered benchmarking work undertaken by consultants on behalf of the Qld DNSPs.[442]

The AER considered the opex ratio analysis and regression analysis met the benchmarking requirements of clauses 6.5.7(e)(4) of the NER.

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[440] 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.

[441] 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.

[442] AER, *Draft decision, Queensland draft distribution determination*, November 2009, appendix I, pp. 624–625 and pp. 659–660.

Submissions

ECCSA, the EUAA, Cement Australia and EnergyAustralia made submissions regarding benchmarking.

AER considerations

The AER has reviewed the issues raised in submissions and provided further information on benchmarking in appendix I of this decision.

AER conclusion

As required under clauses 6.5.6(e) and 6.5.7(e) of the NER, the AER considers it 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 ETSA Utilities.

The AER will continue to refine its benchmarking techniques, and improve the quality of available information in order to expand its usage of benchmarking in evaluating opex and capex proposals.

8.4.7 Debt raising costs

AER draft decision

The AER determined an allowance of a total of $8.2 million for benchmark debt raising costs. This was calculated on the basis of an allowance of 9.1 basis points per annum (bppa) for debt raising and no allowance for the costs associated with refinancing of debt under the completion method.

Revised regulatory proposal

In relation to (standard) debt raising costs, ETSA Utilities:

- accepted the AER's decision to apply a unit rate of 9.1 basis points per annum (bppa), with the total allowance calculated on the basis of this unit rate multiplied by the debt proportion of the regulatory asset base (RAB) each year[443]

- indicated it still had concerns over several aspects of the draft decision, including the exclusion of bonds issued by Fortescue Metals Group and Toyota Finance Australia, and the limitation to bonds of between eight and twelve years tenor in the AER analysis[444]

- provided a memorandum from the Competition Economists Group (CEG) that discussed the AER's method for estimating these costs.[445]

In relation to debt raising costs associated with the completion method, ETSA Utilities:

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443 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 130.

444 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 131.

445 CEG, *Memorandum: AER treatment of the cost of debt raising: Underwriting costs and setting the bond issue size*, 18 December 2009 (CEG, *Memo on debt raising costs*, December 2009).

- did not accept the draft decision, which provided no allowance for these costs[446]
- repeated its proposal for an allowance, based upon a unit rate of 11.2 bppa, calculated in the same way as the standard debt raising costs[447]
- did not provide any additional evidence to support these costs, but indicated it would submit a consultant report in late January 2010.[448]

ETSA Utilities therefore proposed a total allowance for debt raising costs of $19 million for the next regulatory control period.[449]

Submissions

ETSA Utilities submitted a report from PriceWaterhouseCoopers to support its claim for debt raising costs associated with the completion method.[450] This submission is considered in detail in appendix J.

AER considerations

Direct debt raising costs—standard

Debt raising costs are costs which are incurred each time debt is raised or refinanced. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs. The AER has previously accepted that debt raising costs may be a legitimate expense for which a DNSP should be provided an allowance.[451]

The AER notes ETSA Utilities accepted the draft decision on applying a benchmark (direct) debt raising cost of 9.1 bppa,[452] and ETSA Utilities and CEG do not dispute the two major revisions to the debt raising cost methodology included in the draft decision—amortisation of up-front costs and the inflation of fixed costs.[453] Further, the AER notes, as acknowledged by CEG,[454] that several of the remaining criticisms of the AER's methodology would not result in material changes to the final debt raising allowance even if CEG's suggestions were implemented. Nonetheless, the AER considers each matter raised by ETSA Utilities in turn below.

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446 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 130.
447 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 130.
448 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 131.
449 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 131.
450 ETSA Utilities, *Re: Benchmarking debt raising costs associated with the completion method*, 16 February 2010, and PWC, *ETSA Utilities: Distribution network service provider refinancing costs: Final report*, February 2010.
451 AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007, pp. 94–97; AER, *Final decision, SP AusNet transmission determination 2008–09 to 2013–14*, 31 January 2008, pp. 148–150; AER, *Final decision, ElectraNet transmission determination 2008–09 to 2013–14*, 11 April 2008, pp. 84–85 and AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, pp. 183–188, 541–560 (appendix N).
452 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 130.
453 AER, *Draft decision, SA distribution determination,* November 2009, pp. 525–532, appendix I.
454 CEG, *Memo on debt raising costs*, December 2009, p. 4 (paragraph 13).

ETSA Utilities, based on the CEG memorandum, disputed the AER's methodology which excluded several bonds,[455] and submitted that:

- Fortescue Minerals Group (FMG)—it is incorrect for the AER to reject these bonds on the grounds that they were a joint debt and equity issue when the offering memorandum states that the underwriting fee of 2.77 per cent relates to debt transaction only.[456]

- Toyota Finance Australia (TFA)—it is inconsistent for the AER to reject these bonds on the grounds that they reflect an international issuer while including bonds from Rio Tinto and BHP Billiton.[457]

- Leighton Holdings and Myer—the AER could not find these bonds on Bloomberg, but this indicates an error in the AER's search of the service since details of these bonds are available to CEG.[458]

Both CEG and the AER are attempting to locate bonds that match the Allen Consulting Group (ACG) criteria for inclusion in the data set used to calculate debt raising costs (the DRC data set). The AER considers that the fundamental issue underlying the inclusion or exclusion of bonds from the DRC data set is the choice of methodology used to extract data from Bloomberg:

- The CEG approach, based on the Bloomberg SRCH function, involves searching for bonds within the entire Bloomberg database.[459]

- The AER approach, based on the Bloomberg LEAG function, uses the official Bloomberg LEAG tables that report underwriting fees to locate bonds within the entire Bloomberg database.[460]

The AER has already noted that the criteria for inclusion of bonds in the official LEAG tables align with the ACG criteria for the relevant bonds to be included in the DRC data set.[461] For example, the LEAG tables appropriately exclude bonds that despite being Australian in legal form are international in substance.[462] In contrast,

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455 These bonds were first proposed for inclusion in CEG, *Debt and equity raising costs: A report for ETSA*, June 2009, pp. 6–8 (sections 2.1.3–2.1.4) and 34–36 (appendix A). This report was included as attachment E.17 to ETSA Utilities, *ETSA Utilities Regulatory proposal 2010–2015*, 1 July 2009. The AER detailed its reasons for rejecting the bonds in AER, *Draft decision, SA distribution determination*, November 2009, pp. 518–524 (appendix I).

456 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 131; and CEG, *Memo on debt raising costs*, December 2009, pp. 1–3 (paragraphs 4–9). The source document is FMG Finance Pty Ltd, *Offering memorandum: Senior secured notes*, 11 August 2006, lodged with the ASX on 14 August 2006 (FMG Finance, *Offering memorandum*, August 2006).

457 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 131 and CEG, *Memo on debt raising costs*, December 2009, pp. 1–2 (paragraphs 2–4).

458 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 131 and CEG, *Memo on debt raising costs*, December 2009, p. 2 (paragraph 4).

459 CEG, *Memo on debt raising costs*, December 2009, p. 2.

460 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 520–522.

461 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 521.

462 International in substance refers to the fact that the default risk on these bonds is linked to international operations, not Australian operations, as assessed by Bloomberg—for example, the

the bonds returned under the CEG approach do not align with the ACG criteria for inclusion. The SRCH function can inappropriately return bonds that are not straight debt,[463] and does not locate bonds issued within the required period that have already reached maturity (but which may provide relevant information for the purposes of the DRC data set).[464]

Further, the AER observes that the CEG approach tends to produce data containing a number of inconsistencies:[465]

- Duplication of bonds—for example, the four FMG bonds are each reported twice (with different International securities identification number (ISIN) identifiers).[466]

- Inconsistent field data—for example, one Fosters Brewing Group (FBG) bond is reported with an underwriting fee but not a total fee; whereas another FBG bond is reported with a total fee but not an underwriting fee.[467]

- Contradictory field data—for bonds which have both an underwriting fee and a total fee listed, there are instances where the underwriting fee is above the total gross fee.[468]

The AER considers that these limitations with the CEG approach—the return of inconsistent data—provide reasons to prefer the LEAG tables as the means to locate relevant bonds within the Bloomberg database. The AER will continue to use the LEAG function as the initial filter for identification of bonds to be included in the DRC data set. Consistent with its previous approach, the AER will then examine these bonds to ensure that they fully align with the ACG criteria.[469]

Within this framework, the AER considers the four contentious bonds and notes the following:

- FMG—these bonds are reported in the LEAG table:

three TFA bonds. See CEG, *Debt and equity raising costs*, June 2009, p. 35 and AER, *Draft decision, SA draft distribution determination*, November 2009, p. 521.

463 For instance, the Myer bond issued on 1 August 2006. See CEG, *Debt and equity raising costs*, June 2009, p. 35.

464 For example, the BHP Billiton bond issued 26 March 2007 with maturity on 29 March 2009 does not appear when using the Bloomberg SRCH function on 10 March 2010. See AER, *Draft decision, SA draft distribution determination,* November 2009, pp. 523–524.

465 The AER had previously noted that the CEG approach tends to not correctly report bond amounts, misreporting Euros as US dollars, but this minor problem can be overcome by selecting the appropriate fields.

466 CEG, *Debt and equity raising costs*, June 2009, pp. 34–36, appendix A. The bond ISINs are US30250BAB53, XS0265078716, US30250BAA70, XS0265075886, XS0265079524, XS0265132604, US30250BAC37 and XS0265076777, from Bloomberg data accessed 10 March 2010.

467 Bond ISINs are US30239XAB38 and US30239XAD93, from Bloomberg data accessed 10 March 2010.

468 For example, ISIN XS0335716154, which has an underwriting fee of 0.5 per cent but total fee of 0.25 per cent, from Bloomberg data accessed 10 March 2010.

469 AER, *Draft decision, SA draft distribution determination,* November 2009, pp. 518–524.

- The AER was not previously aware of the reference to commission fees of 2.77 per cent, which is now quoted by ETSA Utilities (based on the CEG memorandum).
- However, after further examination of the documentation, the AER still considers this figure may not be indicative of the actual underwriting costs for the debt component of the transaction.[470] First, this commission fee is paid by the project group, not FMG Finance, and does not appear on the project financing plan.[471] Second, the paragraph quoted by CEG is internally inconsistent—2.77 per cent of the $US2051 million raised would equate to $US56.7 million, not $US52.45 million as stated in the offering document.[472] Third, the offering document paragraph includes statements such as:
- As agreed with Leucadia, Fortescue will pay to Jefferies a fee for advisory services that Jefferies provided to Leucadia in connection with the Leucadia funding.[473]
- Jefferies is the co-manager of the FMG bond issues,[474] reinforcing the view that these transactions are not separable.
- Regardless, the second reason given in the draft decision for exclusion of the FMG bonds has not been addressed by ETSA Utilities—failure to break down the aggregate underwriting fee for bonds of different maturities.[475] Given that the debt raising cost methodology requires amortising the up-front costs over the life of the bond, the AER considers that without this information no valid underwriting fee can be calculated.

- TFA—these bonds are not reported in the LEAG table:
  - Bloomberg, via the LEAG table, makes the assessment that the TFA bonds differ in substance from the BHP Billiton and Rio Tinto bonds, not the AER.
  - The AER notes that there can be extremely complex interactions within a group of related companies, and that contractual terms can link the risk of a particular debt issue to particular operations of an otherwise global entity. In this context, it is prudent to rely on a professional service, such as Bloomberg, that is dedicated to performing such assessment.

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470 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 131 and CEG, *Memo on debt raising costs*, December 2009, p. 3 (paragraph 8).
471 FMG Finance, *Offering memorandum*, August 2006, pp. 39, 40 and 230.
472 Further, this difference does not arise as a result of exchange rate fluctuations, since the document uses an exchange rate of US$1.273 = €1. FMG Finance, *Offering memorandum*, August 2006, p. 230.
473 FMG Finance, *Offering memorandum*, August 2006, p. 230.
474 FMG Finance, *Offering memorandum*, August 2006, p. 3.
475 AER, *Draft decision, S A draft distribution determination*, November 2009, p. 522.

    - The AER does not consider it inconsistent to exclude bonds issued by TFA—on country of risk grounds[476]—and include bonds from global companies such as BHP Billiton and Rio Tinto, because this is how they have been classified by Bloomberg.[477]

- Leighton—this bond issue is not reported in the LEAG table:

    - The AER notes that the Leighton bonds were issued to support a specific Indonesian operation and listed on the Singapore stock exchange.[478]

    - Although Leighton is an Australian company, it appears that the Bloomberg assessment of these bonds is that they are sufficiently linked to the Indonesian operations such that the substance of the bonds is non-Australian. As with the TFA bonds, the AER considers it reasonable to rely on the Bloomberg assessment that these bonds are international in substance.[479]

- Myer—this bond issue is not reported in the LEAG table:

    - The AER notes that the Myer notes issue was convertible debt, allowing discounted conversion to equity in the event that the company was publicly floated (as occurred in November 2009).[480]

    - Since these bonds are not straight debt, they are appropriately excluded under the ACG criteria for the DRC data set.

The AER notes that the LEAG tables correctly classify bonds from three of the four companies above in accordance with the ACG criteria for inclusion in the DRC data set. In contrast, the SRCH technique does not classify bonds from any of the four companies in accordance with the ACG criteria.

ETSA Utilities noted that the AER determined benchmark debt raising costs based on bonds issued with a 10-year tenor, and in practice this meant only bonds between 8 and 12 years tenor were considered.[481] ETSA Utilities stated that this was not part of the ACG methodology, reduced the amount of available information, and as such ETSA Utilities did not agree with this aspect of the AER's approach.

The AER observes that the formation of both 5-year and 10-year tenor groups is explicitly discussed in the 2004 ACG report on debt raising costs, and confirms that the limits for the 10-year group (tenor greater than 7.5 years and less than 12.5 years)

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476 The AER clarifies that 'country of risk' does not refer to sovereign risk, but that the risk of the bonds defaulting is linked to overseas operations such that they are not Australian in substance, as assessed by Bloomberg.

477 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 521.

478 Leighton Holdings, *Leighton launches US$110 million debt issue to support operations in Indonesia*, 10 May 2006.

479 International in substance refers to the fact that the default risk on these bonds is linked to international operations, not Australian operations, as assessed by Bloomberg—for example, the three TFA bonds. See AER, *Draft decision, SA distribution determination*, November 2009, p. 521.

480 Myer Holdings Limited, *Prospectus*, 5 October 2009, p. 137.

481 CEG, *Memo on debt raising costs*, December 2009, p. 3, paragraph 10.

match those from the spreadsheet analysis used by ACG. ACG explicitly acknowledged that the benchmark bond is 10 years, but proposed the simple division of the debt raising costs from the 5-year tenor group, which resulted in a conservative approximation. However, in its regulatory proposal, ETSA Utilities—based on the CEG report—proposed moving to the more complicated (but more accurate) process of amortisation of the up-front costs. Accordingly, the only variation from the ACG methodology is the refinement proposed by ETSA Utilities.

Further, it is incorrect to state that this change reduces the amount of information available. Previously, only data from the 5-year group had an impact on the final estimate of debt raising costs, but now only data from the 10-year group has an impact. All things being equal, the change from one group to another does not necessarily involve a reduction in data. The AER notes that the DRC data set for the draft decision has the same number of bonds in the 5-year and 10-year tenor group.[482]

CEG also discussed the issue of data paucity, and advocated including all bonds regardless of tenor in the DRC data set, particularly those of 5-year tenor.[483] CEG stated that it was inappropriate to exclude shorter bonds from the sample set because it was inconsistent to match the 10-year tenor requirement of the NER but not the BBB+ credit rating or the 60 per cent gearing level.

When constructing any sample set, the AER begins with the closest available match to the theoretical benchmark firm. If there are insufficient data points perfectly matching the benchmark, the sample set is expanded to include the closest available comparators. The closest available comparators are those with variations from the benchmark that are not expected to systematically bias the sample set.[484]

The AER considers that there are clear grounds for controlling the tenor of bonds in the DRC data set. The one-off debt raising costs have to be spread across the term of the bond, so the fundamental mathematical relationship requires that tenor must be tightly controlled.[485] This is confirmed by academic evidence, as the original ACG report states:[486]

> …academic research has found tenor to be a major and statistically significant determinant of cost on a bppa basis.

This academic research includes papers by Amira and Handorf; Livingston and Zhou; Cai, Helwege and Warga; and Kim, Palia and Saunders,[487] all of which have been

482 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 524.
483 CEG, *Memo on debt raising costs*, December 2009, pp. 3–4, paragraphs 10–12.
484 An example of the implementation of this method is in AER, *Final decision, WACC parameters*, May 2009, pp. 100–110.
485 Two theoretical exceptions can be posited. First, if discounting is assumed away and debt raising costs scale perfectly linearly with bond tenor. Second, if discounting is allowed and debt raising costs scale perfectly based on an annuity formula matching the discount rate. Neither case is supported empirically.
486 ACG. *Debt and equity raising costs*, December 2004, p. xvii.
487 Amira, K. and W. C. Handorf, 'Global debt market growth, security structure, and bond pricing', *Journal of Investing*, Spring 2004, vol. 13(1), pp. 79–90; Livingston, M. and L. Zhou, 'The impact of rule 144A debt offerings upon bond yields and underwriter fees', *Financial management*, Winter 2002, vol. 31(4), pp. 5–27; Cai, N., J. Helwege, and A. Warga, 'Underpricing in the Corporate Bond Market', *The Review of Financial Studies I*, 2007, vol. 20(5), pp. 2021–2046; and

cited by CEG in submissions to the AER on the issue of debt raising costs. Relevantly, the AER notes CEG's previous submission on the difference resulting from 5-year or 10-year amortisation of up-front costs, which emphasised the significant difference between the two.[488]. The AER considers that the 10-year tenor group, in accordance with the ACG methodology, must be restricted to a tight range around 10 years to avoid the systematic distortion in debt raising costs that would occur if shorter term bonds were included.

The benchmark bond has a credit rating of BBB+, which is recognised as investment grade. The AER considers that, so long as the bond rating is investment grade, there is no reason to restrict the credit rating of bonds in the DRC data set as it unlikely to have an impact on debt raising costs. The ACG report states:[489]

> …there is no empirical evidence that there is an underwriting fee differential between different issues that are investment grade, other things being equal.

This academic research includes papers by Lee, Lochhead, Ritter and Zhao; Altinkilic and Hansen; and Livingston and Zhou, all of which have been cited by CEG in previous submissions to the AER.[490] The consensus finding is that although credit rating has a material effect on the cost of debt itself—that is, the level of interest paid— it has no impact on the cost of raising the debt.[491]

The AER notes that the four FMG bonds are rated B by Standard and Poor's, and so do not conform to the ACG criteria that bonds be of investment grade. The AER considers that inclusion of these bonds in the DRC data set would distort the measurement of debt raising costs and therefore excludes them on this basis. The AER notes that all other bonds in the DRC data set are rated BBB or higher—that is, investment grade.

Finally, the AER notes that there is no suggestion in academic research or financial theory that the level of gearing has an effect on debt raising costs, separate from its effect on credit rating. Thus, after accounting for credit rating, there is no need to restrict the bonds in the DRC data set to those from entities with 60 per cent gearing.

CEG also stated that although it was appropriate for the AER to update the median domestic bond issue size using a five year rolling window, the AER had chosen the wrong dates for this window.[492] Specifically, the AER should have used a window

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Kim, D., Palia, D., and Saunders, A., The impact of commercial banks on underwriting spreads: Evidence from three decades, *Journal of Financial and Quantitative Analysis*, December 2008, vol. 43(4), pp. 975–1000.

488 CEG, *Debt and equity raising costs: A response to the AER 2008 draft decisions for electricity distribution and transmission*, January 2009, p. 48, paragraph 161–164.

489 ACG, *Debt and equity raising costs*, December 2004, p. xvii.

490 Lee, I., S. Lochhead, J. Ritter, and Q. Zhao, 'The Costs of Raising Capital', *The Journal of Financial Research*, 1996, vol. 19(1), pp. 59–74; Livingston, M. and L. Zhou, The impact of rule 144A debt offerings upon bond yields and underwriter fees, *Financial management*, Winter 2002, vol. 31(4), pp. 5–27; Altinkilic, O., and R. Hansen, 'Are there economies of scale in underwriting fees? Evidence of rising external financing costs', *Review of Financial Studies*, 2000, vol. 13(1), pp. 191–218.

491 ACG, *Debt and equity raising costs*, December 2004, p. 52.

492 CEG, *Memo on debt raising costs*, December 2009, p. 4 (paragraphs 17–18).

that either included bonds at the end of 2004,[493] or excluded bonds at the beginning of 2005.[494] CEG stated that either window resulted in a median issue size of $245 million,[495] lower than the AER figure of $263 million.[496]

In the draft decision, the AER used a five year rolling window ending on the date of the draft decision, 30 November 2009. However, the AER accepts that the precise rolling window should be five years up to the date that the data set was last updated, which was as close as practical to the date of the draft decision. The domestic bond data set was last updated on the 5 November 2009, so this means that the five year rolling window commenced on 5 November 2004. Therefore the 16 November 2004 and 26 November 2004 bonds should have been included in the data set and the median domestic bond issue size is $250 million.[497]

Consistent with the draft decision and in accordance with the approach based on the ACG methodology, the AER updates the benchmark direct debt raising costs allowance using the nominal vanilla WACC (used to amortise up-front costs) of 9.76 per cent. This results in the debt raising costs shown in table 8.4.

Table 8.4: Direct debt raising costs with a nominal vanilla WACC of 9.76 per cent

Fee	Explanation	1 Issue	2 Issues	4 Issues	7 Issues	12 Issues
Amount Raised	Multiples of median medium term notes ($250m)	$250m	$500m	$1000m	$1750m	$3000m
Gross underwriting fee	Median gross underwriting spread, up front per issue	7.25	7.25	7.25	7.25	7.25
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	1.00	0.50	0.29	0.17
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 (bppa)	10.8	9.8	9.3	9.1	9.0

Source: ACG, Bloomberg, AER analysis.

493 Specifically, bonds from 28 October 2004, 16 November 2004 (two bonds) and 26 November 2004.
494 Specifically, bonds from 4 March 2005 (two bonds), 13 April 2005 (two bonds) and 14 June 2005.
495 The AER notes that CEG has incorrectly calculated the median of the second group, which is $240 million, not $245 million.
496 CEG, *Memo on debt raising costs*, December 2009, p. 5 (paragraph 19).
497 This does not match the CEG proposal because it does not include the 28 October 2004 bond.

ETSA Utilities has an opening RAB of $2.8 billion. On the basis of the assumed benchmark gearing ratio of 60:40, the notional debt component of ETSA Utilities' opening RAB is around $1.7 billion. Based on the ACG methodology, this debt size would require around 7 bond issues. As such, the AER considers that an allowance of 9.1 bppa for debt raising costs is a reasonable benchmark for ETSA Utilities. Using the post–tax revenue model (PTRM), this benchmark is multiplied by the debt component of ETSA Utilities' RAB to derive an average debt raising allowance of $1.6 million per annum ($2009–10).

Debt raising costs—completion method

The AER's detailed analysis and considerations of ETSA Utilities' proposed debt raising costs associated with the completion method are set out in appendix J. In summary, the AER considers that the benchmark firm should be compensated for the efficient costs of a refinancing plan. However, the AER does not consider that the allowance proposed by ETSA Utilities—based on the PwC report—should be added to the (standard) direct debt raising costs allowance based on the ACG methodology. The AER considers that the allowance for (standard) direct debt raising costs already includes the efficient costs of a refinancing plan and that no increase in these costs is required.

AER conclusion

For the reasons discussed, and as a result of the AER's analysis of ETSA Utilities' revised regulatory proposal and additional information, the AER is not satisfied that the proposed benchmark total debt raising costs reasonably reflect the opex criteria, including the opex objectives. The AER considers that making a $10.2 million reduction to ETSA Utilities' forecast debt raising costs results in expenditure that reasonably reflect 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 8.5 sets out the AER's conclusion on the benchmark debt raising costs for ETSA Utilities.

Table 8.5: AER conclusion on debt raising costs ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Debt raising costs	1.5	1.6	1.7	1.7	1.8	8.3

8.4.8 Feed–in tariffs

AER draft decision

The AER accepted ETSA Utilities' forecast for feed–in tariff expenditure and considered that the proposed forecasting methodology was reasonable. The AER also accepted ETSA Utilities' proposal for a pass through event to provide for differences between actual and forecast allowances for feed–in tariff payment in the next regulatory control period as reasonable and has nominated a feed–in tariff event as a nominated pass through event.[498]

The AER noted that ETSA Utilities did not include an allowance for feed–in tariffs in its opex forecast because it considered that the most appropriate approach to managing its feed–in tariff obligation was through a rule change to the NER. However, the AER incorporated the forecast feed–in tariff payments into ETSA Utilities' total opex requirements.[499]

Revised regulatory proposal

ETSA Utilities accepted the draft decision with respect to its feed–in tariff payments forecast in its revised forecast opex allowance.[500] In preparing its revised regulatory proposal, ETSA Utilities reviewed its sales and demand forecasts, together with its forecast of the uptake of photovoltaic systems that allow qualifying customers to feed electricity into the distribution network. As a result of its review, ETSA Utilities revised its forecast feed–in tariff payments for the next regulatory control period, incorporating an increase of $9.8 million, to a total of $48.6 million. Table 8.6 sets out ETSA Utilities revised feed–in tariff forecast.

Table 8.6: ETSA Utilities revised proposal on feed–in tariff opex ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities revised proposal	7.0	8.7	10.1	11.1	11.7	48.6

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 132.

Consultant review

PB reported that ETSA Utilities' forecasting methodology involved:[501]

- analysis of the existing PV installations in terms of capacity and annual generation
- independent forecasts of new installations by NIEIR accounting for Renewable Energy Certificates (REC) prices, multipliers and costs
- analysis of the average amount of PV generation used in house and the net amount exported to the grid
- application of a tariff of 44c/kWh to the net energy exported to the grid.

PB also reported that the key assumptions applied by ETSA Utilities include the assumption that typical installations are 1.4kW and 55 per cent of the annual energy

[498] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 243.
[499] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 243.
[500] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 132.
[501] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 39.

production of 2.2MWh would offset 25 per cent of in-house consumption, with the remainder exported to the grid.[502]

PB considered that ETSA Utilities applied a reasonable and transparent forecasting methodology to its revised forecast of feed–in tariff payments for residential PV installations, and that it is consistent with its original submission. PB noted that the key difference in the forecast is due to an update in the anticipated number of PV installations increasing from 25 500 to 34 570 in 2014–15, as advised by NIEIR. PB considered that ETSA Utilities' update will ensure consistency between the sales and demand forecasts set out in its revised proposal and ETSA Utilities' forecast of the payments that it expects to make for feed–in tariffs and therefore reduce the likelihood of a pass through application being made by ETSA Utilities to account for differences between the forecast and actual feed–in tariff payments made in 2010–11.[503]

PB considered the forecast opex for feed–in tariffs is prudent and efficient given the forecasting methodology applied.[504]

AER considerations

Based on the information provided by ETSA Utilities in its revised regulatory proposal, PB's review of this information and the AER's assessment of ETSA Utilities' approach in its draft decision, the AER considers that the approach ETSA Utilities used to determine its forecast opex allowances for feed–in tariff payments for the next regulatory control period is reasonable. ETSA Utilities' projected uptake of solar PV generators is consistent with that accepted by the AER in its analysis of demand forecasts in chapter 6 of this decision. The AER therefore considers ETSA Utilities' forecast feed–in tariff payments of $48 million for the next regulatory control period is reasonable.

The AER confirms the draft decision that differences between actual and forecast allowances for feed–in tariffs will be treated as a nominated pass through event for the next regulatory control period. The AER's consideration of ETSA Utilities' proposed feed–in tariff pass through event is set out at chapter 15 of this decision.

AER conclusion

For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, submissions, PB's report and other material, the AER is satisfied that ETSA Utilities' forecast feed–in tariff opex results in expenditure that reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

[502] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 39.
[503] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 39.
[504] PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 39.

8.4.9 Revised cost escalators

AER draft decision

The AER did not accept the methodologies used to develop ETSA Utilities' real cost escalators. As a result, ETSA Utilities' forecast opex was reduced by $38 million.[505]

Revised regulatory proposal

ETSA Utilities did not accept the AER's internal labour escalator. ETSA Utilities stated that while, in general, it had adopted the AER's labour escalation model, it amended the model to account for the impact of ETSA Utilities' Enterprise Bargaining Agreement (EBA).[506]

ETSA Utilities accepted the AER's approach to calculating real cost escalators for construction and other outsourced services. However, ETSA Utilities updated its construction related services escalator with the latest available data released from the Construction Forecasting Council (CFC).[507]

ETSA Utilities adopted all of the AER's recommendations on materials cost escalation, excluding the use of LME forward contract prices for 63 months and 123 months for aluminium and copper, on the basis that these are too thinly traded to be reliable.[508] ETSA Utilities proposed using Consensus Economics long term forecasts instead[509] and used updated data in calculating its materials cost escalation rates.[510]

Submissions

ECCSA raised concerns in relation to real cost escalation. In particular, ECCSA stated that the AER view appears to be that any real increase in costs is justification for an increased allowance to the regulated business.[511]

ECCSA also raised specific concerns in relation to wages cost growth and materials cost growth.

In relation to wages growth, ECCSA considered that the AER had taken an overly conservative approach.[512] ECCSA stated that the AER must include a productivity gain to offset wage growth, in keeping with jurisdictional regulators. ECCSA recommended that the state-wide increases in wages be the surrogate to establish the productivity benchmark for ETSA Utilities.[513]

In relation to materials cost escalation, ECCSA stated that the AER should not adopt an approach of forecasting materials price growth. ECCSA stated that such forecasts will invariably be conservative in favour of the businesses. ECCSA also stated that businesses have historically demonstrated the capacity to absorb materials cost

505 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 245.
506 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108, attachment F.10, pp. 7–8.
507 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.
508 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.
509 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, pp. 3–4.
510 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.
511 ECCSA, *A response*, February 2010, p. 19.
512 ECCSA, *A response*, February 2010, p. 20.
513 ECCSA, *A response*, February 2010, p. 21.

variation within their capex allowances adjusted by CPI. ECCSA therefore proposed that the AER should only make allowances for defined step changes in business conditions.[514]

The AER's consideration of these submissions is outlined in Appendix G of this decision.

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 Australia.[515]Access Economics' forecasts are discussed in more detail in appendix G.

Access Economics real labour forecasts are set out in table 8.7.

Table 8.7: Access Economics real labour escalation rates for general labour and the EGW sector in South Australia.

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
General	0.7	0.8	1.1	0.2	0.5	1.2	1.5
EGW	1.7	2.3	1.2	0.3	0.5	1.2	1.6

Source: Access Economics, *Forecast growth in labour costs: March 2010 report,* 16 March 2010, p. 79

AER considerations

The details of the AER's assessment of the cost escalators proposed by the ETSA Utilities is set out in Appendix G of this decision.

Labour

The AER notes that ETSA Utilities accepted the AER's internal labour escalators, with the exception of those for 2008–09 and 2010–11.

The AER considered it reasonable to adopt actual wage increases provided for under ETSA Utilities' EBA up until 2009–10.[516] In the AER's modelling of ETSA Utilities' labour costs, the escalation rate for 2008–09 did not reflect the actual impact of ETSA Utilities' 2005 EBA. ETSA Utilities has provided actual EBA impacts which the AER has used in its modelling instead of EGW data provided by Access Economics. As a result, in this decision the AER has applied the 2008–09 escalation rate for internal labour proposed by ETSA Utilities.

ETSA Utilities' observed that the AER's modelling of labour escalators for the draft decision included EBA rates to December 2010, thereby impacting labour escalation rates in 2010–11. This was a modelling error and may explain why ETSA Utilities

[514] ECCSA, *A response*, February 2010, p. 21.
[515] Access Economics, *Forecast growth in labour costs: March 2010 report,* 16 March 2010.
[516] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 477.

misinterpreted the AER's intention to apply EBA wage increases 'until the end of the current agreement'.[517] Rather, as stated in the draft decision, the AER considered it reasonable to adopt current EBA wage increases up until 2009–10. The AER has corrected the modelling error in relation to EBA impacts in 2010–11 for this decision.

The AER notes the concerns raised by ECCSA that the AER took a conservative approach for wage cost growth and considered state-wide wage increases should be treated as a benchmark for productivity. The AER considers that productivity adjustments can be an important factor in forecasting actual business costs and notes this approach is consistent with previous regulatory decisions.[518] The AER notes Access Economics considers productivity factors as a key driver of wage differentials and has incorporated productivity into its modelling.[519] The AER supports the application of Access Economics' productivity impacts in the modelling of its wage cost growth forecasts and does not consider it necessary to include further productivity adjustments. The AER considers Access Economics wage cost growth forecasts reflect a realistic expectation of labour costs

Contract services - construction related

The AER notes ETSA Utilities applied updated construction cost forecasts and CPI forecasts to November 2009, derived by KPMG Econtech.[520]

The AER considers that to develop a robust forecast it is appropriate to update construction cost forecasts.[521] Further to this, and as per the AER's draft decision[522], the AER has incorporated Access Economics' updated EGW labour forecasts and forecast South Australian construction LPI to determine ETSA Utilities' weighted average escalator for construction related contracts, based on the weights outlined by ETSA Utilities.

Materials

The AER notes that ETSA Utilities accepted the AER's recommendations for materials cost escalators, excluding the use of LME 63 month and 123 month contract prices to calculate escalation rates for aluminium and copper.

The AER considers that the method adopted by ETSA Utilities, to use Consensus Economics long term forecasts to establish cost escalators for aluminium and copper, present reasonable material cost escalation.

AER conclusion

Table 8.8 sets out the AER's conclusions on ETSA Utilities' real cost escalators over the next regulatory control period. More detailed information on the AER's final assessment is detailed in appendix G of this decision.

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517 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, p. 6.
518 AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 492.
519 Access Economics, *Forecast growth in labour costs*, 16 March 2010, appendix C, p. 106.
520 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, p. 11.
521 AER, *Draft Decision, SA draft distribution determination*, November 2009, p. 477.
522 AER, *Draft Decision, SA draft distribution determination*, November 2009, p. 481.

Table 8.8: AER conclusions on ETSA Utilities' 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	0.720	0.738
Inflation rate	1.46	3.00	2.50	2.75	2.50	2.50	2.50
Materials[a]	–3.05	–3.84	9.32	–0.46	–0.06	–1.02	–1.34
Labour	1.12	1.80	0.57	0.29	0.52	1.18	1.56
Services – construction related	0.15	1.59	0.63	0.96	2.04	2.21	1.22
Services – other outsourced	0.94	1.17	1.11	0.25	0.51	1.22	1.54

Source: AER analysis.

(a) This composite materials cost escalator is based on ETSA Utilities' application of the materials cost inputs above. Source: ETSA Utilities, *Response to AER expenditure modelling request for ETSA*, 13 April 2010.

For the reasons discussed and as a result of the AER's analysis of ETSA Utilities' revised regulatory proposal, the AER is not satisfied that the proposed real cost escalators reasonably reflect the opex criteria, including the opex objectives. The AER considers that making a $19.7 million reduction to ETSA Utilities' proposed opex results in expenditure that reasonably reflect the opex criteria, including the opex objectives, and is the minimum adjustment necessary for the opex to comply with the NER. In coming to this view the AER has had regard to the opex factors.

Table 8.9 sets out the AER's conclusion on the adjustment to real cost escalators for ETSA Utilities.

Table 8.9: AER conclusion on real cost escalators ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Adjustment to real cost escalators	–1.9	–3.2	–4.2	–5.0	–5.5	–19.7

8.4.10 Other issues

Underspend of regulated opex allowance

ECCSA's submission commented that the draft decision effectively ignores ETSA Utilities' ability to manage its opex as it had a surplus of $40 million of opex in the first four years of the current regulatory control period. ECCSA expressed its concern that the AER's draft decision provides for an increase in ETSA Utilities' opex for the next regulatory control period above the opex allowance provided for in the 2008–09 base year.[523]

In its draft decision, the AER reviewed ETSA Utilities' actual operating expenditure outcomes compared to the allowances set by ESCOSA. The AER estimated that ETSA Utilities is expected to underspend its regulated opex allowance by approximately $22.4 million ($2009–10) or 3 per cent of the allowance set by ESCOSA during the current regulatory control period. The AER estimates that for the first four years of the current regulatory control period, ETSA Utilities' actual opex was $555 million ($2009–10) compared to its approved allowance (including approved pass throughs) of $602 million (2009–10), an underspend of $46.9 million or 7.8 per cent.[524]

As reported in its draft decision, the AER reviewed annual performance reports prepared by ESCOSA in order to identify some of the reasons for the variances from the regulated allowances for the first three years of the current regulatory control period (which accounts for all but $0.2 million of the $46.9 million underspend). Based on its review of ESCOSA's annual performance reports for 2005–06, 2006–07 and 2007–08, the AER noted:[525]

- in 2005–06, in opex categories where actual expenses were lower than the regulated allowances, ESCOSA noted these were primarily the result of timing differences due to delayed expenditure and the introduction of ESCOSA's demand management allowance

- ESCOSA considered that the underspend in demand management and retail contestability were due to timing variations due to delayed expenditure and the combinations of weather, operational requirements and cyclical programs

- for the first two years of the current regulatory control period, total actual opex for maintenance and inspection, vegetation management and emergency response opex was $1.8 million (2.1 per cent) below the combined regulatory allowance for these categories

- for 2007–08, ESCOSA considered the underspend of $8.5 million for maintenance expenditure and retail contestability costs were due to timing differences from delayed expenditure and weather, operational requirements and cyclical programs

- ETSA Utilities overspent in the categories of maintenance and inspection, vegetation management and emergency response by 4.6 per cent, considered by ESCOSA to be important for distribution network reliability.

ESCOSA's methodology for establishing ETSA Utilities' opex forecasts for the current regulatory control period involved deriving a base operating expenditure forecast from 2003–04 operating expenditure and projecting this base forecast into the 2005–2010 regulatory control period by scaling operating expenditure to reflect

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523 ECCSA, *A response*, February 2010, pp. 25–26.
524 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 180.
525 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 181–182.

increases in the cost of labour, materials and external services.[526] In its review of ETSA Utilities' opex allowance for the next regulatory control period, the AER adopted a similar approach to that of ESCOSA but with additional refinements. The additional refinements included not only adjusting the efficient base year (2008–09) opex costs for input cost escalators, but also to account for changes in scope and scale.

The AER considers that ETSA Utilities' opex underspend for the current regulatory control period of about 7.8 per cent for the first four years, and 3 per cent for the full period, to be in part explained by ESCOSA's review of ETSA Utilities' opex performance. The AER further considers that ETSA Utilities' forecasting methodology is suitable for forecasting its opex requirements for the next regulatory control period and that the 2008–09 base year opex represents an efficient amount from which to forecast opex. The AER notes that the underspend in the 2008–09 base year ($0.2 million) is insignificant.

Use of base year

In its discussion of the AER's approach of establishing a base year for forecasting ETSA Utilities' opex for the next regulatory control period, the EUAA raised concerns as to whether a DNSP's regulatory accounts are sufficiently well developed to place reliance on the level of revealed operating expenditure in the base year as representative of efficient expenditure. The EUAA submitted that in the absence of a consistent definition of what constitutes operating and capital expenditure, DNSPs have considerable latitude in how they define expenditure. The EUAA also considered that there are considerably weaker incentives to reduce capex rather than opex, particularly towards the end of the regulatory control period where DNSPs are able to maximise their shareholder returns by reclassifying their operating expenditure as capital expenditure. The EUAA stated that until the AER has developed a reliable system of regulatory accounts, the use of an efficient base year to forecast opex cannot be sustained.[527]

Details of the AER's approach of establishing 2008–09 as the base year for forecasting ETSA Utilities' opex are available in section 8.8.1.3 of the AER's draft decision. In regards to ETSA Utilities' submitted opex information for 2008–09, the AER notes the following:

- under the Regulatory Information Notice (RIN) requirements of section 28F of the NEL, ETSA Utilities submitted details of its operating expenditure information for its standard control services in a form required by the AER

- ETSA Utilities' pro forma established under the RIN to capture the AER's required opex information for 2008–09 was provided in accordance with the cost allocation method (CAM) approved by the AER.[528] The AER's *Cost Allocation Guidelines* requires ETSA Utilities to develop and provide detailed principles and policies for attributing costs to, or allocating costs within, the categories of

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526 ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination, Part A*, April 2005.

527 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 24–25.

528 AER, *Final decision, Electricity distribution network service providers, Cost allocation guidelines*, June 2008.

distribution services that it provides. These detailed principles and policies were included in ETSA Utilities' CAM approved by the AER

- ETSA Utilities provided audited opex data for 2008–09

- the increase in ETSA Utilities' opex between 2007–08 and 2008–09 provides support for the proposition that ETSA Utilities has not unreasonably increased opex during 2008–09.

On this basis, the AER considers that the operating expenditure data provided by ETSA Utilities is suitable to establish an efficient base year from which to forecast opex in the next regulatory control period.

AER assessment methodology

The AER notes, that similar to its view on the AER's assessment of ETSA Utilities' capex allowance for the next regulatory control period, the EUAA raised concerns about the AER's reliance on process, procedures and governance frameworks in determining efficient opex expenditure.[529] The AER addressed these concerns in section 7.4.8 of this decision.

8.5 AER conclusion

The AER has reviewed ETSA Utilities' proposed forecast controllable 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 controllable opex does not reflect a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives

- the proposed controllable opex does not reflect the efficient costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the opex objectives

- the proposed controllable opex has not been demonstrated to be prudent and efficient, and therefore does not reasonably reflect the opex criteria.

As the AER is not satisfied that the controllable opex allowance reasonably reflects the opex criteria, under clause 6.5.6(d) of the NER the AER must not accept the controllable opex proposed by ETSA Utilities. Under clause 6.12.1(3)(ii) of the NER, the AER is therefore required to provide an estimate of the opex for ETSA Utilities over the next regulatory control period which it is satisfied reasonably reflects the opex criteria, taking into account the opex factors. The AER has determined the following specific adjustments to ETSA Utilities' revised proposed forecast opex:

[529] EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 23–24.

- $7.2 million reduction to emergency response opex to reflect a change in the economies of scale factor to be applied to the network growth escalator for emergency response
- $3.3 million reduction to maintenance and repair and emergency response to remove the proposed impact of asset age on forecast maintenance.
- $19.7 million reduction to reflect revised real input cost escalators.
- $8.3 million reduction to the revised forecast self insurance opex.
- $10.2 million reduction to the revised cost for debt raising costs.

Allowing for the adjustments listed above, the AER's estimate of total opex for ETSA Utilities is $1033 million, as set out in table 8.10.

The AER notes the reduction in total allowed net opex compared to the draft decision is driven by changes in input cost escalation rather than additional reductions to ETSA Utilities' controllable opex or other non–controllable opex factors.

Table 8.10: AER conclusion on ETSA Utilities total opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities' proposed forecast opex	199.5	207.7	215.8	226.4	232.3	1081.7
Adjustments to controllable opex	–1.0	–1.5	–2.0	–2.7	–3.3	–10.5
Adjustments to self insurance	–1.5	–1.6	–1.7	–1.7	–1.8	–8.3
Adjustment to debt raising costs	–1.9	–2.0	–2.0	–2.1	–2.2	–10.2
Adjustment to cost escalators	–1.9	–3.2	–4.2	–5.0	–5.5	–19.7
AER opex allowance	193.2	199.4	205.9	214.9	219.5	1032.9

Note: Totals may not add due to rounding.

8.6 AER decision

In accordance with clause 6.12.1(4)(ii) of the NER, the AER does not accept ETSA Utilities' proposed forecast opex for the next regulatory control period. The AER is not satisfied that ETSA Utilities' forecast opex, taking into account the opex factors, reasonably reflects the opex criteria in clause 6.5.6 of the NER.

The AER's estimate of ETSA Utilities' required opex for the next regulatory control period, that reflects the opex criteria taking into account the opex factors, is set out at table 8.10 of this decision.

The AER's reasons for this decision are set out in section 8.4 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 ETSA Utilities. 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 ETSA Utilities' regulatory proposal and the supporting information provided did not constitute persuasive evidence for justifying a departure from a gamma of 0.65 as specified in the AER's statement of regulatory intent on the revised weighted average cost of capital (WACC) parameters (SORI).[530] 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 the underlying criteria.[531]

The AER considered that ETSA Utilities' proposed tax remaining and tax standard asset lives were appropriate. It also considered that ETSA Utilities' proposed opening tax asset base to be appropriate and reasonable, subject to the removal of metering assets used for alternative control services. The AER accepted that gifted assets should be included in the tax calculation.

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 ETSA Utilities' corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	31.9	33.0	32.4	34.0	35.2	166.6

Source: AER, *Draft decision, SA draft distribution determination*, November 2009. p. 279.

9.2 Revised regulatory proposal

ETSA Utilities proposed a total tax allowance of $253.7 million for the next regulatory control period.[532] This revised allowance reflected changes by ETSA Utilities to various factors that affect revenues and costs. ETSA Utilities stated it had not revised the transitional methodology used to determine corporate income tax under a post–tax regulatory approach from that contained in its regulatory proposal.[533]

530 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 (the SORI).

531 NER, clause 6.5.4(h)(1). The underlying criteria was set out in the draft decision, AER, *Draft decision, SA draft distribution determination*, November 2009, p. 275.

532 ETSA Utilities, *Revised regulatory proposal*, January 2010, revised PTRM.

533 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 208.

ETSA Utilities did not accept the draft decision to adopt the gamma of 0.65 specified in the SORI. It proposed a gamma of 0.5, consistent with its regulatory proposal.[534] To support its proposed gamma of 0.5, ETSA Utilities stated:[535]

- a payout ratio of less than 100 per cent should be assumed by the AER when estimating gamma. ETSA Utilities submitted a report by NERA Economic Consulting (NERA) as well as a report by Strategic Finance Group Consulting (SFG) to support this proposal[536]
- multicollinearity is not a material concern for the SFG study, and the issue of multicollinearity applies equally to the Beggs and Skeels (2006) study
- SFG has further interrogated its data set based on a report by Dr. John Field on statistically robust samples. SFG estimated a negligible change to its regression results after this further interrogation of its data set
- franking credit redemption rates from taxation statistics provide little information on the value of franking credits and should not be relied upon
- the AER's approach of averaging the results of a dividend drop–off study and an estimate from tax statistics is upwardly biased.

ETSA Utilities also provided further information in support of its revised proposal on 9 February 2010. This further information incorporated a report from SFG, which revised SFG's theta estimate to account for concerns raised in the draft decision.[537]

The AER signalled in the draft decision that it had included forecasts of gifted assets provided by ETSA Utilities in determining the tax allowance on a provisional basis.[538] ETSA Utilities requested that, to the extent that the AER may change its approach to gifted assets from that set out in the draft decision, it be consulted.

9.3 Submissions

The AER received a joint submission from the Victorian electricity distribution businesses (VEDB) and a submission from the Energy Consumers Coalition of South Australia (ECCSA) on ETSA Utilities' proposed gamma.

The VEDBs submitted ETSA Utilities' revised regulatory proposal supports a gamma that does not exceed 0.5 and there is persuasive evidence for the AER to depart from the gamma of 0.65 adopted in the SORI.[539]

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534 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 195.

535 ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 190–195.

536 NERA, *Payout ratio of regulated firms: A report for Gilbert and Tobin*, 5 January 2010; and SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010.

537 ETSA Utilities, *Letter to the AER*, 9 February 2010; and SFG, *Further analysis in response to AER draft determination in relation to gamma*, 4 February 2010.

538 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 378.

539 VEDB, *Submission in response to WACC issues arising in the AER's draft distribution determination for ETSA Utilities, prepared jointly by the Victorian Electricity distribution businesses*, 16 February 2010, pp. 5–6.

ECCSA stated it supported the draft decision on gamma.[540]

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 ETSA Utilities.

Professor Michael McKenzie and Associate Professor Graham Partington from the University of Sydney provided advice on the estimation of gamma focussing on dividend drop–off based estimates of theta.[541] McKenzie and Partington reviewed the SFG dividend drop–off study submitted by ETSA Utilities in support of its proposed gamma of 0.5 and found significant data and methodological issues.[542] 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.[543]

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.[544] Handley advised that the AER's approach of using both dividend drop–off based and tax statistics based estimates of theta is appropriate.[545]

9.4.2 Tax asset base

In the draft decision, the AER (with the assistance of McGrathNicol Corporate Advisory (McGrathNicol)) assessed ETSA Utilities' tax asset bases for the 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 the tax asset bases proposed by ETSA Utilities. The remaining tax asset lives and standard tax asset lives were also accepted as being consistent with the NER and the NTER.

The AER reengaged McGrathNicol to identify any significant changes in ETSA Utilities' 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 ETSA Utilities and the remaining tax asset lives calculated by ETSA Utilities as at 1 July 2010)
- the treatment of past additions and disposals

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540 ECCSA, *A response*, February 2010, p. 44.
541 McKenzie and Partington, *Report to the AER, Evidence and submissions on gamma*, 25 March 2010.
542 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, pp. 4–5.
543 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 4.
544 Handley, *Report prepared for the Australian Energy Regulator on the estimation of gamma*, 19 March 2010.
545 Handley, *Report prepared for the AER on the estimation of gamma*, 19 March 2010, p. 32.

- the treatment of depreciation on capital contributions
- 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.[546]

9.5 Issues and AER considerations

9.5.1 Assumed utilisation of imputation credits (gamma)

9.5.1.1 Estimating the payout ratio

ETSA Utilities stated that a payout ratio of less than 100 per cent should be assumed by the AER when estimating gamma and submitted a report from NERA to support this proposal. ETSA Utilities submitted that the Officer WACC framework does not address the issue of delayed payout of imputation credits and it is inappropriate for the AER to assume a 100 per cent payout ratio based on the fact that it is consistent with classical tax valuation frameworks.[547]

The VEDBs submitted ETSA Utilities' revised regulatory proposal provided evidence demonstrating that a 100 per cent payout ratio is inconsistent with the behaviour of firms and there is no theoretical or empirical basis to justify an assumption of 100 per cent payout ratio.[548]

As noted in the draft decision, the AER considers that the assumption of a 100 per cent payout ratio is consistent with the Officer WACC framework, which assumes cash flows occur in perpetuity and are therefore fully distributed at the end of each period.[549] The AER notes that this is consistent with the WACC review where a 100 per cent payout ratio for imputation credits was assumed based on a number of considerations, including:[550]

- 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

546 ETSA Utilities has no tax loss carried forward.
547 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 193; and NERA, *Payout ratio of regulated firms*, 5 January 2010.
548 VEDB, *Submission in response to WACC issues*, 16 February 2010, p. 6.
549 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 254, 259.
550 AER, *Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 420.

- 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.

The NERA report submitted by ETSA Utilities stated that Australian Taxation Office (ATO) statistics indicate a payout ratio of 68 per cent.[551] NERA stated the ATO statistics do not support an assumption that retained imputation credits are distributed within five years from when the credits are created.[552]

As noted in the draft decision, the AER considers the WACC review's conclusion that the Hathaway and Officer (2004) estimate of the payout ratio of 71 per cent is reasonable for the immediate payout ratio for imputation credits. The AER notes NERA agreed with this point in its report prepared for the WACC review, and NERA then applied time value considerations to the remaining 29 per cent of imputation credits retained on average each year.

The AER notes NERA's latest payout ratio estimate of 68 per cent actually estimates the payout ratio in any one year—it is the ratio of imputation credits created in one year to imputation credits distributed in that year. As a result, the payout ratio of 68 per cent is an estimate of the immediate payout ratio, and conclusions about the approximately 30 per cent of imputation credits retained each year cannot be drawn from this figure. This is consistent with Handley's advice.

NERA also submitted the appropriate discount rate for retained imputation credits is the cost of equity.[553] The AER notes Handley's advice that retained imputation credits have already been earned and are readily available for distribution by the ATO. Handley noted that, as a result, retained imputation credits do not have the same level of risk as future cash flows that have not been earned and therefore have a discount rate that is lower than the cost of equity. Handley also noted that the discount rate may be above the risk–free rate because of the risk of bankruptcy faced by the average firm.[554]

The AER agrees with Handley and, as noted in the WACC review, considers that the appropriate discount rate for retained imputation credits is somewhere between the risk–free rate and the cost of equity.

SFG stated that, if it is assumed that a firm grows into perpetuity, retained imputation credits can never be distributed. SFG stated if it is assumed that a firm does not grow into perpetuity the only time retained imputation credits could be distributed is when a firm liquidates and at this point the retained imputation credits would have zero or

551 NERA, *Payout ratio of an average firm in the market*, 5 January 2010, pp. 4–6.
552 NERA, *Payout ratio of an average firm in the market*, 5 January 2010, pp. 5–6.
553 NERA, *Payout ratio of an average firm in the market*, 5 January 2010, p. 4.
554 If a firm became bankrupt, retained imputation credits could not be attached to cash flows and therefore the retained credits could not be distributed.

negligible value.[555] As noted in the draft decision, and consistent with the WACC review, the AER considers that retained imputation credits can be distributed through off-market buy backs, dividend reinvestment plans and special dividends throughout the life of a firm.[556]

The AER notes that it is uncertain exactly how long firms are likely to retain imputation credits. However, McKenzie and Partington noted that companies are likely to try to distribute these credits to maximise shareholder wealth.[557] In addition, Handley noted that there are considerable assumptions that need to be made to estimate the exact value of retained imputation credits.[558]

The AER is not aware of any reliable empirical research on the retention period for retained imputation credits or the value of retained imputation credits for Australian companies. However, the AER notes Handley's advice that it is reasonable to assume that the exact payout ratio is likely to lie between 71 per cent and 100 per cent. Handley also noted that a 100 per cent payout ratio is consistent with the Officer WACC framework.[559] McKenzie and Partington noted that a payout ratio of between 70 per cent and 100 per cent is appropriate.[560]

The AER agrees with the advice of its consultants and notes that the actual payout ratio is likely to be between 70 per cent and 100 per cent. 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 framework. Consistent with the WACC review, the AER considers the assumption of a 100 per cent payout ratio is appropriate because:[561]

- 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.[562] The AER considers this remains appropriate due to the difficulty in reliably estimating the value of retained imputation credits.

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555 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, pp. 19–20.
556 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 257; and AER, *Review of the weighted average cost of capital (WACC) parameters*, May 2009, pp. 412, 418.
557 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 26.
558 Handley, *Report prepared for the AER on the estimation of gamma*, 19 March 2010, p. 37.
559 Handley, *Report prepared for the AER on the estimation of gamma*, 19 March 2010, pp. 32–38.
560 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 44.
561 AER, *Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 420.
562 AER, *Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 420.

Based on all the factors discussed above, the AER considers that it remains appropriate to assume a 100 per cent payout ratio consistent with the draft decision and the WACC review.

9.5.1.2 Estimating theta from market prices

ETSA Utilities submitted that SFG fully addressed the concerns raised by the AER in relation to multicollinearity and data filtering. ETSA Utilities submitted reports from SFG, Skeels and Field to support this claim.[563]

The VEDBs submitted ETSA Utilities' revised regulatory proposal demonstrated the SFG dividend drop–off study is reliable.[564]

Multicollinearity

Skeels submitted there is no evidence that multicollinearity is a concern for the Beggs and Skeels (2006) or the 2009 SFG dividend drop–off based estimates of theta.[565]

McKenzie and Partington advised that imputation credits are a monotonic transformation of cash dividends and therefore, theoretically there is perfect correlation between cash dividends and imputation credits.[566] The AER notes that, as a result, multicollinearity is a significant concern for dividend drop–off studies. As noted by McKenzie and Partington and SFG, the only reason perfect multicollinearity does not occur in SFG's data set is because of changes in corporate tax rates and regimes.[567]

The AER notes McKenzie and Partington's analysis of SFG's data set shows that the coefficient of correlation between cash dividends and imputation credits is 0.70 for stock price observations after the 0.03 per cent size filter is applied. This number is 0.9899 for the 2052 observations in SFG's unfiltered data set where dividends are fully franked.[568] The AER considers that this high degree of correlation in the data indicates that SFG's results are prone to multicollinearity.

The AER notes McKenzie and Partington's advice that symptoms of multicollinearity in dividend drop–off studies include large standard errors and estimates of theta that are statistically insignificant.[569] Skeels also noted that symptoms of near perfect multicollinearity include large standard errors and insignificant coefficient estimates.[570]

The AER notes that SFG's estimate of the value of theta in the 1 July 2000 to 10 May 2004 subsample period is not statistically significant. In addition to this, in

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563 ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 193–194.

564 VEDB, *Submission in response to WACC issues*, 16 February 2010, p. 6.

565 Skeels, *Response to Australian Energy Regulator draft determination*, 13 January 2010, p. 18.

566 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 44.

567 Tax rate and regime changes over time are the only reason that cash dividends and imputation credits are not perfectly correlated in SFG's data set. See McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 46; and SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 5.

568 This is 2052 out of SFG's unfiltered sample of 5646 observations.

569 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 45.

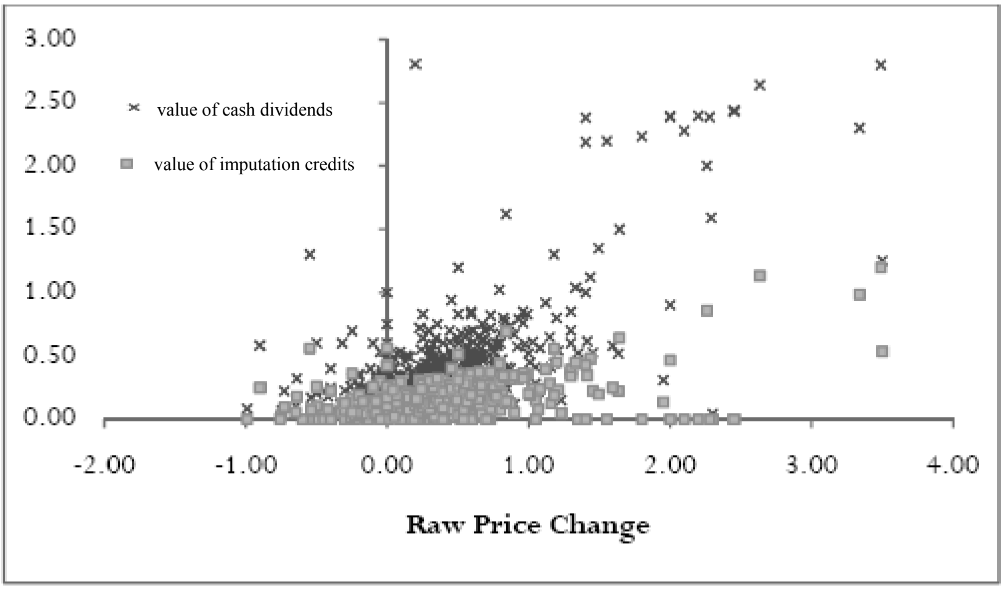
570 Skeels, *Response to Australian Energy Regulator draft determination*, 13 January 2010, p. 17.

the same period, SFG's estimate of the value of cash dividends is greater than one, which is economically implausible. The AER considers that this indicates the presence of multicollinearity in SFG's results.

In comparison, the AER notes that the Beggs and Skeels (2006) estimate of theta for the same period is statistically significant. In addition, the Beggs and Skeels (2006) estimate of the value of a dollar of cash dividend is economically plausible and, as noted by McKenzie and Partington, is consistent with the Australian evidence from dividend drop–off studies.[571]

Skeels stated that although SFG's 1 July 2000 to 10 May 2004 estimate of theta is not statistically significant from zero, the estimate of the value of cash dividends is. Skeels stated that this simply indicated that the majority of the stock price drop–off is likely to be due to the value of cash dividends and that theta is no different to zero.[572] The AER notes that McKenzie and Partington analysed the SFG data set and found that comparing raw stock price change on ex-dividend day against the cash dividend and the imputation credit shows a clustering of both to zero. However, cash dividends do exhibit a more significant positive slope than imputation credits. This is illustrated in figure 9.1.

Figure 9.1: Raw stock price change against cash dividends and imputation credits



Source: McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 48.
Note: The stock price change is graphed along the x–axis; the value of cash dividends and imputation credits paid is graphed on the y–axis.

McKenzie and Partington advised:[573]

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571 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, pp. 30–31.

572 Skeels, *A review of the SFG dividend drop–off study*, 28 August 2009, pp. 18–19; and Skeels, *Response to Australian Energy Regulator draft determination*, 13 January 2010, p.18.

573 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 48.

> Given the inability of the estimation technique to reliably decompose the partial effect of cash dividends and franking credits due to multicolinearity, it is not surprising that the cash dividend dominates in the estimation process.

The AER considers McKenzie and Partington's analysis demonstrates that SFG's regression results are likely to be affected by multicollinearity and as a result the value of imputation credits is likely to be understated. Therefore, the AER considers that SFG's estimated values for cash dividends and theta are likely to be unreliable.

Joint confidence intervals

SFG submitted that the issue of multicollinearity in dividend drop–off studies can be addressed through the use of a joint confidence interval.[574] SFG provided a graph that shows the possible combinations of cash dividend and franking credit values that fit the market data used in its study. Based on this graph, SFG submitted that its regression estimates of the value of cash dividends and imputation credits (0.98 and 0.23 respectively) fall within the same joint confidence interval as the Beggs and Skeels (2006) estimates (0.80 and 0.57 respectively).[575]

The AER notes McKenzie and Partington's advice that the joint confidence interval submitted by SFG actually displays the extent to which multicollinearity affects dividend drop–off based estimates of the value of cash dividends and franking credits.[576] The AER also notes Handley's advice that the joint confidence interval analysis submitted by SFG acknowledges the imprecision in theta estimates from dividend drop–off studies.[577]

The AER considers SFG's analysis of joint confidence intervals does not in any way address the issue of multicollinearity nor does it give any indication of which set of results for the value for imputation credits and cash dividends is most reliable. The AER considers that the breadth of results possible within SFG's joint confidence interval simply highlights large standard errors and the likely impact of multicollinearity on coefficient estimates from dividend drop–off studies, which was noted by the AER in both the draft decision and the WACC review.[578]

Consistency issues

SFG submitted the value of a dollar of cash dividend should be set to 100 cents when estimating the value of franking credits using dividend drop–off studies because this maintains consistency with the capital asset pricing model (CAPM). SFG stated that it is appropriate to set the value of a dollar of cash dividend in this manner because the

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574 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, pp. 5–8.

575 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 7.

576 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, pp. 45–47.

577 Handley, *Report prepared for the AER on the estimation of gamma*, 19 March 2010, pp. 30–31. Handley uses the example of a set of estimates (0.72, 0.78) for the value of cash dividends and imputation credits respectively to demonstrate that SFG's joint confidence interval simply indicates the high variability in possible estimates based on the data.

578 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 272 and AER, *Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 437.

relevant and important dividend drop–off studies that examine unfranked dividends estimate the value of a cash dividend to be 100 cents.[579]

The AER notes McKenzie and Partington's advice that placing restrictions on parameters may bias the least squares estimate unless the restrictions are true.[580] 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 discussed above, 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 takes precedence over other considerations.

The AER also considers that in the presence of multicollinearity, setting the value of a dollar of cash dividend to 100 cents will bias the estimate of theta downwards, because unconstrained estimates provide a value for a dollar of cash dividend below 100 cents. This was illustrated in SFG's report which shows that, for each set of estimates, the higher the value of cash dividends adopted the lower the value of franking credits.[581]

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.[582] Handley further noted:[583]

- Boyd and Jagganathan (1994) rely 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 that is less than 100 cents.

SFG also stated that estimates of theta where a dollar of cash dividend is constrained to be valued at 100 cents fall within the joint confidence interval it has constructed. The AER considers that, as discussed above, the joint confidence interval constructed

579 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, pp. 7–8.
580 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 46.
581 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 7.
582 Handley, *Report prepared for the AER on the estimation of gamma*, 19 March 2010, p. 27.
583 Handley, *Report prepared for the AER on the estimation of gamma*, 19 March 2010, pp. 26–28.

by SFG cannot be used to determine whether estimates of theta and the value of cash dividends are reasonable or not.[584]

Data sampling

Reliability of SFG data based on Dr. John Field's methodology

ETSA Utilities submitted a report from Dr. John Field, which outlined a method for SFG to use to interrogate its data set.[585] Field set out a procedure by which to determine the likely number of unacceptable observations in SFG's data set based on examination of a sample within SFG's data set. Field identified a sample of 150 random observations from SFG's data set of 3201 observations to be analysed for this purpose.[586]

SFG then analysed the sample 150 random observations identified by Field from its data set of 3201 and found:[587]

- 14 observations to be excluded due to price sensitive announcements being made in relation to them
- two observations where dividends were understated.

Therefore, SFG identified 16 observations which are considered unreliable, which is an unacceptability rate of 10.7 per cent in the sample of 150 observations chosen at random. Therefore 6.2 to 16.7 per cent of observations in SFG's full data set are likely to be unacceptable according to Field's analysis.[588] This is illustrated in table 9.2, along with other examples of binomial confidence intervals provided by Field.

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584 The joint confidence interval only shows that the data may produce such a result, regardless of whether the coefficients are separately statistically significant or not.

585 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 193.

586 J. Field, *Reliability of data used in dividend drop–off study*, 5 January 2010, p. 5. The AER notes Field stated he chose 150 random observation from SFG's sample of 1386 (i.e. the sub-sample for the period 1 July 2000–10 May 2004). However, it appears that the 150 observations were chosen at random from the total data set of 3201 for companies with a market capitalisation greater than 0.03 per cent.

587 SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 16.

588 This is at the 95 per cent level of confidence using exact binomial confidence limits.

Table 9.2: Unacceptability rate in SFG's data set

Sample size	Number of unacceptable observations	Unacceptability rate in sample	95% confident that unacceptability rate in whole dataset lies between:
150	16	10.7%	6.2% – 16.7%
160	8	5%	2.2% – 9.6%
150	3	2%	0.4% – 5.7%
150	0	0%	0% – 2.4%

Source: AER analysis; and J. Field, *Reliability of data used in dividend drop–off study*, 5 January 2010, pp. 3–5.

Note: The figures above assume that there is a binomial distribution of unacceptable observations in SFG's data set.

The AER notes that, rather than applying this analysis, SFG revised its estimates after excluding the 14 unreliable observations and correcting two dividends that were found to be understated, and found negligible change in its results. However, Field's analysis suggests that between 198 and 530 observations are unreliable and should be excluded from SFG's data set. This indicates a high level of unreliability within SFG's whole dataset of 3201. The AER notes that re-estimating the regression results after analysing only 150 observations does not mitigate this problem. This is consistent with McKenzie and Partington's advice, which stated that auditing a random sample of observations does not serve any useful purpose.[589]

Filtering of outliers

SFG used Cook's D-statistic to identify the 1 per cent of observations in its data set that were considered unreliable and then analysed these to determine economic reliability. Based on this analysis, SFG excluded 20 influential data points that were considered unreliable. SFG argued that removal of these data points improves the reliability of its results.[590]

The AER notes McKenzie and Partington's advice that the use of Cook's D-statistic may introduce a bias into SFG's analysis because it only excludes individually influential observations that are economically unreliable. This process does not identify groups of observations that are jointly significant.[591]

McKenzie and Partington also advised that identifying the most influential 1 per cent of observations was completely arbitrary and that only one of the observations in SFG's data set of 3201 had a Cook's D-statistic of greater than one, which is generally regarded as the cut-off point.[592]

[589] McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 33.
[590] SFG, *Response to the AER draft determination in relation to gamma*, 13 January 2010, p. 13.
[591] McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 50.
[592] McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 50.

The AER considers this is important because filtered results may reflect filtering rather than the true underlying value of the parameters of interest. This is noted in McKenzie and Partington's advice.[593] McKenzie and Partington also noted that before filtering SFG's data set estimated the combined value of cash dividends and imputation credits to be between –60 and 575 but after filtering the range is –60 to 55.[594]

The AER notes that in comparison, Beggs and Skeels (2006) filtered data ex ante using economic criteria.[595] McKenzie and Partington advised this is more appropriate than identifying individually influential observations and only analysing these.[596]

Based on McKenzie and Partington's advice, the AER considers that the use of Cook's D-statistic is less reliable than the methodology used by Beggs and Skeels (2006) to filter outliers and may likely bias SFG's results.

Exclusion of intercept term

The AER notes that in analysing SFG's results McKenzie and Partington found a statistically significant intercept term which was not reported by SFG.[597] The AER notes that the combined value of cash dividends and imputation credits may therefore be underestimated by the coefficient estimates in the SFG study. In comparison, Beggs and Skeels (2006) report insignificant intercept coefficients.[598] This confirms the AER's concerns about the reliability of the SFG study.

Miscellaneous data issues

The AER notes that SFG's data set contains a large number of zero drop–offs, which is masked by the market adjustment.[599] McKenzie and Partington noted that in SFG's unfiltered data set, 526 out of 5646 observations are zero observations. In SFG's filtered data set, 177 out of 3201 observations are zero observations.[600] McKenzie and Partington advised that this is an abnormally high number of zero observations.[601]

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593 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010 , p. 22.

594 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010 , p. 15.

595 Beggs and Skeels (2006) identified and excluded special dividends, data where information was missing, data where the basis of quotation had changed 5 days either side of the ex–dividend day, as well as data from the volatile month of October 1987. Beggs and Skeels (2006) excluded this data based on economic justifications, see Beggs and Skeels, 'Market arbitrage of cash dividends and franking credits', *The Economic Record*, vol. 82, no. 258, p. 252.

596 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010 , p. 50.

597 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010 , p. 50.

598 Beggs and Skeels, 'Market arbitrage of cash dividends and franking credits', *The Economic Record*, vol. 82, no. 258, p. 243.

599 SFG adjusts all observations by aggregate movements in the all ordinaries share price index to reduce the effect of information affecting the market as a whole, which does not relate specifically to the dividend event. This is consistent with the approach taken by Beggs and Skeels, see McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 38; and Beggs and Skeels, Market arbitrage of cash dividends and franking credits, *The Economic Record*, vol. 82, no. 258, 2006, p. 242.

600 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010. The AER notes that zero observations are likely to indicate that a stock is thinly traded, which would mean that they reflect market information on how investors value either the cash dividends or the attached franking credits.

601 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 18.

The AER also notes the combined number of negative and zero observations in SFG's filtered data set is high. McKenzie and Partington advised that almost 20 per cent of SFG's filtered data set comprise zero or negative observations.[602]

These data issues contribute to the AER's concerns about the reliability of the SFG study. Therefore, the AER confirms the draft decision that the Beggs and Skeels (2006) study provides the most reliable estimate of theta from market prices.

McKenzie and Partington advised that a number of other data issues affect dividend drop–off studies, including:

- dividend announcements across firms tend to be clustered in time, which introduces a bias into the estimation process[603]
- thinly traded stocks included in a data set may reduce the accuracy of dividend drop–off study estimates because they may not fully reflect market valuation[604]
- the bid–ask spread of stocks in a data set may affect the ability of a dividend drop–off study to extrapolate the value assigned to cash dividends and franking credits. For example, if the bid–ask spread on a stock is larger than the cash dividend this task is very difficult[605]
- price sensitive information may be released around the ex-dividend date for a stock and therefore alter the stock price to incorporate this information in addition to the reflecting the value that investors place on cash dividends and franking credits.[606]

Given these issues with dividend drop–off studies, the AER considers it appropriate to maintain the approach set out in the draft decision, which uses estimates from both market prices as well as tax statistics. The AER notes that McKenzie and Partington also advised that it is preferable to consider results from both tax statistics and market prices rather than rely on one type of study or the other.[607]

602 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 38. The AER notes that negative observations are theoretically implausible in the context of a dividend drop–off study. Once shares go ex-dividend, they do not confer the benefit of the cash dividend or the franking credit on a purchaser. Therefore, for negative observations, it is likely that factors other than the ex-dividend event are contributing to the share price behaviour, which reduces the accuracy of dividend drop–off results.

603 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, pp. 23, 42.

604 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 39.

605 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, pp. 39–42.

606 McKenzie and Partington set out the significant effect that noise may have on dividend drop–off studies by demonstrating significantly less variable stock price drop–offs where the cum-dividend and ex-dividend prices are measured no more than 1 minute. See McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, pp. 15–17, 36.

607 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 10.

Additional SFG report addressing earlier data concerns

ETSA Utilities submitted a further report from SFG to support its revised regulatory proposal.[608] In this report, SFG outlined additional analysis undertaken in response to concerns raised by the AER in the draft decision relating to the following:[609]

- special dividends
- stock splits and bonus issues
- contemporaneous price sensitive announcements
- missing observations
- thin trading.

SFG updated its estimation results by incorporating changes designed to address the issues outlined above. The AER notes this analysis does not address the concerns outlined above regarding the effect of multicollinearity on SFG's estimation results, the reliability of SFG's data set based on the Field report, SFG's filtering of outliers, as well as other data issues noted in McKenzie and Partington's advice.

The AER also notes the additional SFG analysis may not fully address the issue of thin trading. SFG stated that its data set comprises only those observations where a trade can be identified on the ex-dividend day.[610] However, McKenzie and Partington noted SFG does not identify if any attempt was made to ensure that the cum-dividend price observation was current.[611] McKenzie and Partington also noted that if a cum–dividend price is not current the change observed over the ex-dividend date could incorporate other information in addition to the drop–off due specifically to the payment of a dividend, thus diluting estimation results.[612]

9.5.1.3 Reasonable ranges and estimates of theta

Skeels submitted that the AER's estimate of theta is upward biased by construction. Skeels stated that the AER acknowledged that labelling the Beggs and Skeels (2006) estimate of theta a lower bound estimate was inappropriate and not intended to carry the meaning in a statistical sense. Skeels stated the Handley and Maheswaran (2008) estimate of theta from tax statistics, however, is an upper bound for the value of theta.[613] The VEDBs also submitted that it supports ETSA Utilities' revised regulatory proposal in relation to the use of tax statistics and that is inappropriate to use tax statistics in estimating theta as it will overstate the value of theta.[614]

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608 SFG, *Further analysis in response to AER draft determination in relation to gamma*, 4 February 2010.

609 SFG, *Further analysis in response to AER draft determination in relation to gamma*, 4 February 2010, pp. 3–4.

610 SFG, *Further analysis in response to AER draft determination in relation to gamma*, 4 February 2010, p. 4.

611 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 39.

612 McKenzie and Partington, *Evidence and submissions on gamma*, 25 March 2010, p. 39.

613 Skeels, *Response to Australian Energy Regulator draft determination*, 13 January 2010, pp. 10–12.

614 VEDB, *Submission in response to WACC issues*, 16 February 2010, pp. 5–6.

The AER notes it acknowledged that labelling the Beggs and Skeels (2006) study as a lower bound estimate of theta was inappropriate and was not intended to carry the meaning in the statistical sense.[615] However, the AER also noted that the 0.74 estimate of theta by Handley and Maheswaran (2008) was not an upper bound on the reasonable range of estimates for theta, based on tax statistics. As noted in the draft decision, and consistent with the WACC review, the AER considers that a reasonable range of estimates for theta based on tax statistics is 0.67 to 0.81 and a point estimate of 0.74 is a reasonable point estimate for theta based on tax statistics.[616]

The AER considers that neither the Beggs and Skeels (2006), nor the Handley and Maheswaran (2008) estimates of theta provide statistical bounds on the value of theta. The AER considers, as noted in the draft decision and in the WACC review, that reasonable point estimates for theta based on market prices and tax statistics are 0.57 and 0.74 respectively.[617] The average of these point estimates, 0.65, was adopted in the WACC review and subsequently in the draft decision as the most reasonable estimate for theta.[618] The AER considers that this remains the most reasonable estimate of theta based on the available evidence.

The AER notes that its approach to estimating theta, as outlined in the draft decision based on the outcomes of the WACC review, is supported by ECCSA.[619]

9.5.1.4 Conclusion

The AER has considered the information provided by ETSA Utilities on gamma as part of its revised regulatory proposal and submissions, including consultants' reports. The issues raised relate to both the payout ratio and 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 simplifies the framework for estimating gamma 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.

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.

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615 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 273 and AER, *Review of the weighted average cost of capital (WACC) parameters*, May 2009, p. 456.
616 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 261.
617 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 274; and AER, *Review of the weighted average cost of capital (WACC) parameters*, May 2009, pp. 448, 456, 466, 467.
618 AER, *Review of the weighted average cost of capital (WACC) parameters*, May 2009, pp. 466–468.
619 ECCSA, *A response*, February 2010, p. 44.

The AER notes that both the Beggs and Skeels (2006) study and the Handley and Maheswaran (2008) 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 ETSA Utilities in support of its revised regulatory proposal 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.

McGrathNicol noted the reclassification of metering services as a significant change from ETSA Utilities' regulatory proposal. However, McGrathNicol found that this change was consistent with the draft decision concerning the reclassification of these services.[620] McGrathNicol also noted ETSA Utilities had provided the revised capex for 2008–09 based on actuals.[621] The AER accepts both these changes made by ETSA Utilities and the resulting impact on the tax asset base. The issue of metering classification was discussed in chapter 2 of this decision, while the revised capex figure for 2008–09 is discussed in chapter 5.

McGrathNicol did not identify any other significant changes in ETSA Utilities' revised regulatory proposal regarding the tax asset base, although it did reiterate certain findings in its report for the draft decision.[622] These matters were previously considered by the AER, and it was satisfied these matters were not material.[623]

Gifted assets are a form of customer contribution that are treated as income for tax purposes. ETSA Utilities is allowed to receive a tax allowance to reflect this treatment. The AER has reconsidered the forecasts for gifted assets as provided by ETSA Utilities for the draft decision and has decided that these forecasts are appropriate for use in this decision.

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620 McGrathNicol, *Assessment of the revised proposal of ETSA Utilities' tax asset base*, 29 March 2010, p. 5.
621 McGrathNicol, *Assessment of ETSA Utilities' tax asset base*, 29 March 2010, p. 6.
622 McGrathNicol, *Assessment of ETSA Utilities' tax asset base*, 29 March 2010, pp. 6–7.
623 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 278.

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. In its revised regulatory proposal, ETSA Utilities proposed a revised standard asset life for amortising equity raising costs, including for tax purposes. 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.[624] The AER has therefore applied a standard tax asset life for equity raising costs of 5 years in ETSA Utilities' PTRM. The AER's decision on the standard asset life associated with equity raising costs for regulatory depreciation purposes is discussed in chapter 10 of this decision.

With the exception of the standard tax asset life for equity raising costs, the AER notes ETSA Utilities did not alter its standard tax asset lives from those approved in the draft decision. While the remaining tax asset lives have changed, these changes stem from matters accepted by the AER, as discussed above. Accordingly, the AER considers ETSA Utilities' proposed tax asset base (including the standard and remaining tax asset lives) is consistent with the requirements of the NER.

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 ETSA Utilities has 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 ETSA Utilities' 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 9.3. These figures are calculated using the PTRM and based on the tax inputs discussed above.

[624] ATO, *Guide to depreciating assets 2001-02: Business» related costs - section 40-880 deductions, ATO reference; NO NAT7170.*

Table 9.3: AER conclusion on ETSA Utilities corporate income tax allowances ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	32.3	32.6	32.0	33.6	34.6	165.2

9.7 AER decision

In accordance with clause 6.12.1(7) of the NER the estimated cost of corporate tax to ETSA Utilities for each regulatory year of the next regulatory control period is as specified in table 9.3 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 ETSA Utilities' proposed asset lives used to calculate its 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 ETSA Utilities as inputs to its post–tax revenue model (PTRM), and the resulting regulatory depreciation allowance. The AER accepted the remaining and standard asset lives proposed by ETSA Utilities, subject to one exception related to the standard life for office equipment.[625]

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER determined ETSA Utilities' regulatory depreciation allowance for the next regulatory control period as set out in table 10.1. These figures reflected the removal of metering assets used for alternative control services from the RAB for standard control services.

Table 10.1: AER draft conclusion on ETSA Utilities' regulatory depreciation ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014-15	Total
Regulatory depreciation	100.3	113.1	126.6	142.4	157.9	640.4

Source: AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 285.
Note: Regulatory depreciation represents the net effect of the straight line depreciation of ETSA Utilities' assets and the indexation of those assets due to inflation.

No submissions were received regarding ETSA Utilities' depreciation allowance.

10.2 Revised regulatory proposal

ETSA Utilities proposed a total regulatory depreciation allowance of $636 million for the next regulatory control period.[626] ETSA Utilities stated that its revised

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625 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 283–284.

626 This amount is lower than the draft decision due to the higher opening RAB proposed by ETSA Utilities and the higher negative depreciation that results from the indexation of those assets due to inflation.

depreciation allowance reflected responses to matters raised by the AER in the draft decision. In particular, ETSA Utilities stated that its revised depreciation allowance (compared to the allowance in the draft decision) includes the impact of changes to:[627]

- the opening RAB to correct for what ETSA Utilities considered to be an error by the ESCOSA in the treatment of certain capital contributions (see chapter 5 of this decision)
- forecast capex.

Standard asset lives

ETSA Utilities accepted the standard asset lives as set out in the draft decision, including the change made by the AER to the office equipment category in the roll forward model (RFM).[628]

Remaining asset lives

ETSA Utilities revised the remaining asset lives of the various asset categories as at 1 July 2010 contained in its revised PTRM. The changes were due to ETSA Utilities updating 2008–09 capex for actuals and revising its forecasts of 2009–10 capex.[629]

Equity raising costs

ETSA Utilities disputed the draft decision on the number of years (52.3 years) over which equity raising costs should be amortised. ETSA Utilities proposed that equity raising costs be amortised over 20.6 years.[630]

ETSA Utilities argued that if the depreciated opening asset values were to be used by the AER to calculate the standard asset life of equity raising costs for amortisation purposes, the AER should calculate this life by either:[631]

- 'dividing the total annual depreciation by the total opening asset base'[632] (which according to ETSA Utilities gives a weighted life of 41.2 years), or
- using the remaining asset lives of the assets (which according to ETSA Utilities gives a weighted life of 15.8 years), rather than their standard asset lives. ETSA Utilities stated it was inconsistent to apply new asset lives against the depreciated asset values.

However, ETSA Utilities' preferred approach to calculating the asset life for equity raising costs was to use forecast capex over the next regulatory control period, not the assets in place at the start of that period. ETSA Utilities noted that equity raising is inextricably linked to new capex. ETSA Utilities stated that the NER requires depreciation schedules to be linked to the nature of assets. It observed that if there was

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627 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 201.
628 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 203.
629 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment K.1.
630 ETSA Utilities, *Revised regulatory proposal*, January 2010, Attachment F9.
631 ETSA Utilities, *Revised regulatory proposal*, January 2010, Attachment F9, pp. 7–9.
632 The AER presumes ETSA Utilities means: dividing the total opening asset base by total annual depreciation.

no new capex, then no equity raising would be needed. Accordingly, ETSA Utilities proposed that the asset life for equity raising costs reflect the weighted average standard lives of the assets in ETSA Utilities’ proposed capex program for the next regulatory control period. Furthermore, ETSA Utilities used annual depreciation to determine the weighted average. On this basis, ETSA Utilities calculated the weighted average standard life for equity raising costs to be 20.6 years, based on its revised capex proposal.[633]

10.3 Issues and AER considerations

Standard asset lives

The standard asset lives proposed by ETSA Utilities in its revised regulatory proposal are unchanged from those proposed in its regulatory proposal and accepted by the AER in its draft decision. The AER therefore confirms its draft decision and accepts the standard asset lives proposed by ETSA Utilities. These standard asset lives are shown in table 10.3.

Remaining asset lives

The revisions to ETSA Utilities remaining asset lives as at 1 July 2010 are due to ETSA Utilities updating 2008–09 capex for actuals and revising its forecasts of 2009–10 capex. The AER reviewed the revisions and considers the adjustments to be appropriate. It has accepted the remaining asset lives as at 1 July 2010 in ETSA Utilities’ revised regulatory proposal. These remaining asset lives are shown in table 10.3.

Equity raising costs

The AER does not agree with ETSA Utilities’ claim that it incorrectly calculated the weighted average standard life for amortising equity raising costs in the draft decision.

ETSA Utilities’ approach of dividing the total opening asset base by total annual depreciation to give a weighted standard life is not an appropriate way to calculate a weighted average. Table 10.2 provides a simple illustration with only two asset categories. Using ETSA Utilities’ approach, the weighted standard life for these assets would be 20 years—that is, the opening asset value of $120 divided by the annual depreciation of $6.[634] However, the correct approach as calculated by the AER results in a weighted standard asset life of 42.5 years. Accordingly, ETSA Utilities’ approach would underestimate the applicable weighted average standard life. This arises from weighting the value of the standard asset life by depreciation values (which can inappropriately bias towards short lived assets) rather than the real asset values (which provide a more appropriate value weighting to assets with different lives).

[633] ETSA Utilities, *Revised regulatory proposal*, January 2010, Attachment F9, pp. 9–10.

[634] ETSA Utilities’ approach of dividing the opening asset value by annual depreciation to work out the asset life can be done on an individual asset class basis. However, ETSA Utilities’ approach can not be used to work out a weighted average across more than one asset class when the asset lives differ across these classes.

Table 10.2: Example—calculating a weighted average life (years)

Asset type	Opening asset value	Standard asset life	AER weighted life	Depreciation per annum	ETSA Utilities weighted life
Asset 1	$100	50	41.67[a]	$2	16.67
Asset 2	$20	5	0.83	$4	3.33
Total	$120		42.50	$6	20.00

Note: Straight–line depreciation assumed.
(a) For example, this figure was calculated by dividing $100 by $120 and multiplying the resulting ratio by the standard asset life (50).

The AER does not agree that, if the opening asset values are used to determine the weighted average standard life, the remaining lives of these assets need to be used instead of the standard lives. This is because equity raising costs are related to future financing needs, including future capex needs as ETSA Utilities observed. Accordingly, standard lives are the appropriate benchmark to use.

However, while it is true that equity raising costs are related to future capex, it is the entity as a whole (as a going concern) that gives rise to the need for equity raising costs. A DNSP does not simply own the new assets associated with its proposed capex program, but it owns all of the assets that comprise its network and business. The weighted life of equity raising costs for amortisation purposes should therefore reflect the standard lives of all assets. In this regard, the AER does not accept ETSA Utilities' proposal that the weighting of the assets lives should only be in proportion to ETSA Utilities' proposed capex program, as this approach would ignore existing assets, which indirectly (through their effect on the DNSP's ability to raise funds internally) are a key component in the analysis of future external financing needs.

Furthermore, the link between capex and equity raising is not direct. Other factors (business–wide factors)[635] influence whether or not external equity is needed and how much. The AER also notes that there is no obligation on ETSA Utilities to spend the exact amount of the approved capex allowance or that the capex incurred will be based on the asset mix contained in ETSA Utilities' proposal. To this end, the actual opening asset values in the RAB provide fixed measurable proportionate values and therefore are appropriate to use for determining a value weighted average.

Based on the considerations above, the AER considers that a weighting based on ETSA Utilities' proposed approach to calculate the standard asset life for amortising equity raising cost would not be consistent with clause 6.5.5(b)(1) of the NER. Instead, the AER confirms its draft decision that the weighted standard asset life for amortising equity raising costs should be based on the weightings of the actual (depreciated) opening asset values. This approach is consistent with that applied by the AER in previous transmission/distribution determinations.[636] The standard asset

[635] Business wide factors include the items assessed in the equity raising cost cash flow analysis.
[636] See for example: AER, *Final decision, NSW distribution determination 2009–10 to 2013–14*, 28 April 2009, pp. 194, 213–14; AER, *Final decision, TransGrid transmission determination 2009–10 to 2013–14*, 28 April 2009, p. 97.

life of ETSA Utilities’ equity raising costs, as determined by the AER, is shown in table 10.3.

10.4 AER conclusion

The AER has accepted the standard and remaining asset lives for ETSA Utilities as set out in table 10.3.

Table 10.3: ETSA Utilities approved remaining and standard asset lives (years)

Asset class	Standard life	Remaining life
System assets		
Sub-transmission lines	55	49.9
Distribution lines and cables	55	21.1
Distribution transformers	45	18.3
Substations	45	18
Low voltage supply	55	14.7
Communications	15	8
Land[b]	na	na
Easements[b]	na	na
Net Customer Contributions	40.2	35.3
Non-system assets		
Information systems	5	4.9
Plant and tools/ furniture and fittings	10	7.2
Vehicles- heavy fleet	20	7.14
Vehicles- light fleet	5	na[a]
Buildings	40	23.4
Land[b]	na	na
Equity raising costs	52.3	na

(a) Asset category for new additions from 1 July 2010, no opening asset value transferred from other categories.
(b) 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 determined ETSA Utilities’ regulatory depreciation allowances for the next regulatory control period, as set out in table 10.4.

Table 10.4: AER conclusion on ETSA Utilities regulatory depreciation ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014-15	Total
Regulatory depreciation	100.2	113.3	126.8	142.5	157.7	640.5

Note: Regulatory depreciation represents the net effect of the straight line depreciation of ETSA Utilities' assets and the indexation of those assets due to inflation.

10.5 AER decision

In accordance with clause 6.12.1(8) of the NER the AER has not accepted the depreciation allowance submitted by ETSA Utilities. The AER has determined the depreciation allowance for ETSA Utilities 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 ETSA Utilities for the next regulatory control period, and deals with issues raised in ETSA Utilities' revised regulatory proposal and submissions—specifically the determination of the risk–free rate, market risk premium (MRP), 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 ETSA Utilities 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.[637] 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.

ETSA Utilities adopted the WACC parameters specified in the SORI for the equity beta, gearing ratio and credit rating.[638] The AER noted the acceptance of these parameters.

ETSA Utilities submitted a departure from the SORI in respect of its proposed MRP of 8 per cent.[639] The AER considered the information provided in support of the regulatory proposal did not constitute persuasive evidence for justifying a departure from a MRP of 6.5 per cent.[640]

The AER calculated an indicative nominal vanilla WACC of 10.02 per cent for ETSA Utilities. The indicative WACC was higher than that proposed by ETSA Utilities because the nominal risk–free rate had increased since the time ETSA Utilities submitted its regulatory proposal. The impact of the increase in the nominal risk–free rate was partly offset by applying a MRP of 6.5 per cent. Table 11.1 outlines the WACC parameter values for the draft decision.

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637 NER, clause 6.5.4(h).

638 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.

639 ETSA Utilities also proposed a departure from the SORI with regard to the value of gamma, which is a parameter relevant to estimating the tax building block. The AER's consideration of gamma is set out in the tax chapter 9.

640 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 303–318.

Table 11.1: AER draft conclusion on WACC parameters

Parameter	
Nominal risk–free rate	5.37%
Real risk–free rate	2.85%
Expected inflation rate	2.45%
Gearing level (Debt:Equity)	60:40
Market risk premium	6.5%
Equity beta	0.80
Debt risk premium	4.29%
Nominal pre-tax return on debt	9.66%
Nominal post-tax return on equity	10.57%
Nominal vanilla WACC	10.02%

Source: AER, *Draft decision, SA draft distribution determination*, November 2009, p. 345.

11.2 Revised regulatory proposal

ETSA Utilities adopted a nominal vanilla WACC of 10.02 per cent consistent with the draft decision.[641] In revising its WACC, ETSA Utilities adopted a MRP of 6.5 per cent and accepted the approach to estimate the DRP by reference to the CBASpectrum fair value curve.

11.3 Submissions

The AER received submissions regarding the cost of capital from:

- DUET Group (DUET)[642]
- Energy Consumers Coalition of South Australia (ECCSA)[643]
- Energy Users Association of Australia (EUAA)[644]
- Victorian electricity distribution businesses (VEDBs).[645]

DUET submitted that the AER's analysis of the prevailing cost of equity was flawed because it failed to account for capital growth expectations and incorrectly considered

641 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 197.
642 DUET, *South Australian draft distribution determination 2010–11 to 2014–15*, 29 January 2010.
643 ECCSA, *A response*, February 2010.
644 EUAA, *Submission to the AER on ETSA Utilities*, February 2010.
645 VEDB, *Submission in response to WACC issues arising in the AER's Draft Distribution Determination for ETSA Utilities*, 16 February 2010.

that DUET's overseas and unregulated assets altered its required return on equity.[646] DUET stated that the prevailing cost of equity for the relevant sector remained significantly higher than the cost of equity set in the draft decision.[647]

ECCSA submitted that the cost of capital in the draft decision was above market expectations, and that the debt risk premium was excessive compared to the actual funding costs for ETSA Utilities.[648]

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.[649] 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 cost of capital set by the AER for ETSA Utilities. 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.[650]

The VEDBs stated that the MRP of 6.5 per cent adopted in the draft decision understated the MRP that is likely to prevail in the next regulatory control period.[651]

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 5.37 per cent (effective annual compounding rate) in the draft decision. This was based on the average across 18 business days from 18 September 2009 to 13 October 2009 for Commonwealth Government Securities (CGS) yields with a 10–year maturity, using indicative mid-rates published by the Reserve Bank of Australia (RBA). The AER agreed to ETSA Utilities' 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 its final decision.[652]

ETSA Utilities revised proposal

ETSA Utilities noted that the value for the nominal risk–free rate in its revised regulatory proposal was indicative and that it will be updated based on the agreed averaging period.[653]

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646 DUET, *South Australian draft distribution determination*, 29 January 2010, pp. 1–2.
647 DUET, *South Australian draft distribution determination*, 29 January 2010, p. 3.
648 ECCSA, *A response*, February 2010, p. 44.
649 This statement is not referenced to a particular WACC review submission. EUAA, *Submission to the AER on ETSA Utilities*, February 2010, p. 11.
650 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 11–12.
651 VEDB, *Submission in response to WACC issues*, 16 February 2010.
652 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 296.
653 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 197.

Submissions

The EUAA stated that ETSA Utilities was not funded through Commonwealth government gilts, and that it was therefore inappropriate to set the risk–free rate based on 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.[654]

AER considerations

The AER considers that the proposal by the EUAA to set the risk–free rate with regard to international capital markets would not be consistent with the basis on which other parameters of the cost of capital are estimated. That is, the AER applies a domestic CAPM,[655] deriving estimates of all WACC parameters on this basis, and it would be invalid to change one component of the WACC equation in isolation.[656] The AER also notes that submissions on this matter 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 ETSA Utilities and agreed to by the AER. For this decision, the AER determines the risk–free rate, based on the average across 18 business days from 29 March 2010 to 23 April 2010 for CGS yields with a 10–year maturity, using indicative mid-rates published by the RBA. The resulting nominal risk–free rate is 9.76 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 Market risk premium

AER draft decision

The AER considered that ETSA Utilities' regulatory proposal and supporting information from its consultants for a MRP of 8 per cent did not provide persuasive evidence to depart from the MRP of 6.5 per cent set out in the SORI.[657]

ETSA Utilities revised proposal

ETSA Utilities adopted a MRP of 6.5 per cent, consistent with the SORI and the draft decision, but stated it did not necessarily agree with or accept the underlying economic analysis. ETSA Utilities maintained that at the time of lodging its regulatory proposal there was significant risk in financial markets that implied a higher medium run MRP than the SORI allowed.[658]

Submissions

The VEDBs stated that the current conditions in the global economy and capital markets are still very fragile in the wake of the global financial crisis (GFC), placing

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[654] EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 11–12.

[655] 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.

[656] The EUAA also proposed changing the allowed rate of return to be based on international cost of capital—this is considered in section 11.4.5.

[657] AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 317–318.

[658] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 190.

upward pressure on the MRP. The VEDBs submitted the value for the MRP in the SORI understated the MRP that is likely to prevail in the next regulatory control period, and this would impact on investment incentives in a manner contrary to the long term interests of consumers and hence the national electricity objective (NEO).[659]

AER considerations

The AER notes the views of ETSA Utilities and the VEDBs, including supporting commentary since the release of the draft decision that current market conditions remain abnormally volatile. The AER observes there is contradictory commentary on the recovery from the GFC and corresponding reduction in volatility in global markets, such as the RBA in its recent statement on monetary policy:[660]

> …Domestically, most economic indicators continued to point to a strengthening in economic activity…
>
> …Members noted that the staff forecasts showed that economic activity would grow at around trend rates over the next couple of years. Indeed, some recent indicators suggested that growth might already have been running at or close to trend for a few months…
>
> …Members took note of the positive developments in the financial sector, including early signs that credit to business was becoming easier after the difficult period last year.

The AER notes that many of the quotes presented by the VEDBs relate to international conditions, when the relevant context is the Australian capital market. The AER considers that the Australia market is showing continued signs of recovery from the GFC and that there are some indicators that the MRP may have already returned to the long-term equilibrium of 6 per cent.

The AER considers the term over which the MRP is estimated has to be consistent with the term adopted for the nominal risk–free rate for internal consistency within the capital asset pricing model framework.[661] The term of the nominal risk–free rate is 10 years, a period longer than the next regulatory control period, under which short-term fluctuations to market volatility would have a relatively small effect. The AER notes that a MRP of 6.5 per cent may be considered as conservative when accounting for current prevailing conditions, but notes that there is still insufficient evidence at this time to justify departure from the MRP determined in the SORI to one consistent with a more stable economic outlook. Accordingly, the AER considers the estimation of a MRP of 6.5 per cent, a figure above the long–run MRP of 6 per cent, is commensurate with the current economic climate and the long–term parameterisation of the MRP.

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[659] VEDB, *Submission in response to WACC issues*, 16 February 2010, pp. 2–5.
[660] RBA, *Minutes of the Monetary Policy Meeting of the Reserve Bank Board*, 2 March 2010.
[661] AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 377–309.

11.4.3 Debt risk premium

11.4.3.1 AER draft decision

The AER determined a DRP of 4.29 per cent. The AER considered the use of CBASpectrum's BBB+ fair value curve provided the best available prediction of observed yields for the 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.

11.4.3.2 ETSA Utilities revised proposal

ETSA Utilities accepted the draft decision to use CBASpectrum as the sole data source for the estimation of the DRP, rather than an average of Bloomberg and CBASpectrum fair value curves. However, ETSA Utilities indicated that it did not accept the reasoning behind the AER's selection of CBASpectrum as the better alternative, and submitted a report from CEG (the CEG report on the bond sample) that critiqued the AER's methodology for selecting a data source. In particular, ETSA Utilities stated that that the test implemented by the AER was not appropriate, robust, transparent or consistent, and at times produced results that were at odds with a 'sense-check' of prevailing market conditions. Further, ETSA Utilities did not accept the AER's interpretation of clause 6.5.2(e) of the NER regarding the properties of a benchmark bond.[662]

11.4.3.3 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 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.[663]

ECCSA submitted that the cost of capital in the draft decision was too high, and also referenced a research note from Credit Suisse. This research note referred to the actual cost of debt for ETSA Utilities, which Credit Suisse estimated was 130 basis points below the benchmark DRP estimated by the AER's approach at the time the debt was issued. The EUAA stated that although the AER should have regard to the SORI, it should act to remove the inconsistency between the estimated cost of debt and the actual cost.[664]

11.4.3.4 AER considerations

The AER notes that the DRP is set with regard to the Australian benchmark BBB+ corporate bond rate. The experience of two particular businesses' (SP AusNet and

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[662] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 195.
[663] EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 11–12.
[664] ECCSA, *A response*, February 2010, p. 44.

ETSA Utilities) recent capital raisings in isolation 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 would not be consistent with the basis on which the other parameters of the cost of capital are estimated. That is, the AER applies a domestic CAPM,[665] deriving estimates of all WACC parameters on this basis, and it would be invalid to change one component of the WACC equation in isolation.[666]

The AER notes that ETSA Utilities accepted the draft decision, but indicated that it considered there were flaws in the testing undertaken by the AER. In response to these statements, the CEG report and other submissions, the AER further refined its methodology for testing the accuracy of Bloomberg and CBASpectrum fair value curves against observed market data relevant to the benchmark corporate bond. In this section the AER's standard methodology to select between these data sources is outlined, with the latest refinements indicated. The AER then applies the method 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.[667]
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,[668] 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

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665 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.

666 The EUAA also proposed changing the allowed rate of return to be based on an international cost of capital—this is considered in section 11.4.5.

667 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.

668 Consistent with the credit rating set out in the SORI.

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.[669] If the change is statistically significant then the AER considers relevant market developments to assess whether a fundamental shift in 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.[670] 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.[671] The Tribunal also noted that the AER needs to reconsider the data sources and methodology in future determinations.[672] The AER has reconsidered its methodology and has made some refinements. The refinements are 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

ETSA Utilities—citing the CEG report on the bond sample—raised the following issues in response to the draft decision:

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669 G. Chow, *Tests of equality between sets of coefficients in two linear regressions*, Econometrica, July 1960, vol. 28(3).

670 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 i^th bond

$Observed_{i,j}$ is the j^{th} observed yield for the i^{th} bond, taken from either Bloomberg, CBASpectrum or UBS

$Fair_{i,j}$ is the j^{th} fair yield for the i^{th} bond, taken from either Bloomberg, CBASpectrum or an average of the two.

671 Australian Competition Tribunal, *Application by Energy Australia and other [2009] ACompT8*, November 2009, p. 39.

672 Australian Competition Tribunal, *Application by Energy Australia and other [2009] ACompT8*, November 2009, p. 39.

- the inclusion of more bonds in the sample set by relaxing certain criteria (for example, including floating rate bonds in addition to fixed rate bonds)[673]

- subjectivity regarding the method used to determine which bonds in the population should be excluded from the sample of bonds for analysis.[674]

Increasing the number of bonds in the sample

CEG stated that the sample of bonds used by the AER in its analysis only includes bonds with a term to maturity of between two and six years. For this reason, CEG outlined that the AER's method of testing, selects the fair value curve which most accurately reflects observed yields between two and six years but not necessarily bonds with a maturity of 10 years. CEG outlined that the AER's test may not select the best estimate for a bond with a maturity of 10 years if there are systematic differences present in either bond yields or fair value curves for bond terms greater than six years.[675]

To address this issue CEG suggested that the number of bonds in the population could be increased to include:[676]

- bonds which have observations available from at least one of Bloomberg, UBS and CBASpectrum[677]

- floating rate bonds which have had their yields converted to fixed rates using prevailing swap rates[678]

- bonds with other credit ratings[679]

- bonds issued in Australia by foreign companies.[680]

The AER recently considered the first three of these points in its April 2010 decision for Country Energy's Wagga Wagga gas distribution network.[681] Although the AER found some merit in these suggestions, there was no practical way to incorporate these alternative bond types in the bond sample analysis with an appropriate weighting. The

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673 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates: A report for ETSA Utilities*, January 2010, p. 9, paragraph 30.
674 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates: A report for ETSA Utilities*, January 2010, pp. 9–10, paragraph 32.
675 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates: A report for ETSA Utilities*, January 2010, pp 10–12, section 4.2.
676 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates: A report for ETSA Utilities*, January 2010, p. 9 (paragraph 30), p. 13, paragraph 48.
677 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates, A report for ETSA Utilities*, January 2010, p. 15 (paragraph 51), pp. 21–23, section 5.1.
678 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates, A report for ETSA Utilities,* January 2010, p. 15 (paragraph 55), pp. 23–25, section 5.2.
679 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates,* A report for ETSA Utilities, January 2010, p. 14, paragraph 54, and pp. 25–27, section 5.3.
680 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates*, *A report for* ETSA Utilities, January 2010. p. 14, paragraphs 52–54, and pp. 34, 25–27, section A5.53.
681 AER, *Final decision, Access Arrangement proposal, Wagga Wagga natural gas distribution network*, 1 July 2010–30 June 2015, March 2010, pp. 31–35.

AER did, however, compare graphs of the additional bond data to the selected fair value curve and found that they did not provide any new or reliable information that could be used to draw a meaningful conclusion.[682]

Bonds from non-Australian companies

CEG outlined that the sample size for bonds can be increased to include bonds issued in Australia by non-Australian companies, often labelled 'kangaroo bonds'.[683] The AER notes that the NER specifically defines the DRP with regard to Australian bonds.[684] In its October 2009 decision on the Victorian Advanced Metering Infrastructure (AMI),[685] the AER considered a similar proposal and stated:[686]

> The AER also notes that it has regarded the term 'Australian' as referring to corporate bonds issued in Australia by Australian privately owned businesses and not by government entities. This definition excludes bonds issued by Australian companies overseas and bonds issued by overseas companies in Australia.

Further, the Bloomberg fair value curve explicitly excludes bonds from non-Australian companies, with a separate 'kangaroo fair value curve' generated for these bonds. Comparing an Australian fair value curve (that is, based on bonds issued by Australian companies) to observed yields on kangaroo bonds is, essentially, attempting to measure how well the fair value curve meets a criterion that is different from its original purpose. The AER therefore considers that including bonds from non-Australian companies in the data set does not aid in the selection of the fair value curve that best meets the legislative criteria.

Conclusion on increasing the number of bonds in the sample

The AER considers that CEG outlined that a range of bonds contain valuable information which the AER can have regard to in order to ensure that the selected fair value curve generally reflects the available information from the financial market. However, for the reasons outlined above and in the previous AER decision,[687] the AER considers that CEG's proposal to increase the sample size—that is, to include bonds not available from all three data sources, floating rate bonds, bonds with other credit ratings and bonds from overseas companies—has limitations. Consequently, the AER will not use these additional bonds in the bond sample analysis to determine which fair value curve is used to estimate the benchmark debt risk premium.

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682 AER, *Final decision, Access Arrangement proposal, Wagga Wagga natural gas distribution network*, 1 July 2010–30 June 2015, March 2010, pp. 40–43.

683 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates, A report for ETSA Utilities*, January 2010. p. 14 (paragraphs 52–53 54), 3425–27 (section A5.53).

684 NER, clause 6.5.2(d).

685 AER, *Victorian advanced metering infrastructure review: 2009–11 AMI budget and charges applications, final determination*, October 2009, pp. 117, 125–126; and AER, *Victorian advanced metering infrastructure review: 2009–11 AMI budget and charges applications, draft determinati*on, July 2009, p. 121.

686 AER, *Victorian advanced metering infrastructure review: 2009–11 AMI budget and charges applications, final determination*, October 2009, p. 117.

687 AER, *Final decision, Access Arrangement proposal, Wagga Wagga natural gas distribution network, 1 July 2010–30 June 2015*, March 2010, pp. 31–43.

Determining which bonds to exclude from the sample

Under the AER's standard methodology a bond may be excluded from the sample of bonds if it is identified as not being representative of a BBB+ rated bond.[688] This may be the case if the observed yield on the bond makes it an outlier.

CEG proposed three alternative statistical tests to determine whether the observed yield on a bond is an outlier—Chauvenet's test, the classic outlier test, and the box plot test.[689] The AER describes and considers these tests in the final decision for Country Energy's Wagga Wagga gas distribution network.[690] The AER considers that the three tests suggested in the CEG report can be used to augment the AER's approach to identifying outliers based on the Chow test.

The AER also considers CEG's proposed approach 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.[691]

11.4.3.5 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 11.2.

Table 11.2: 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.

688 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.

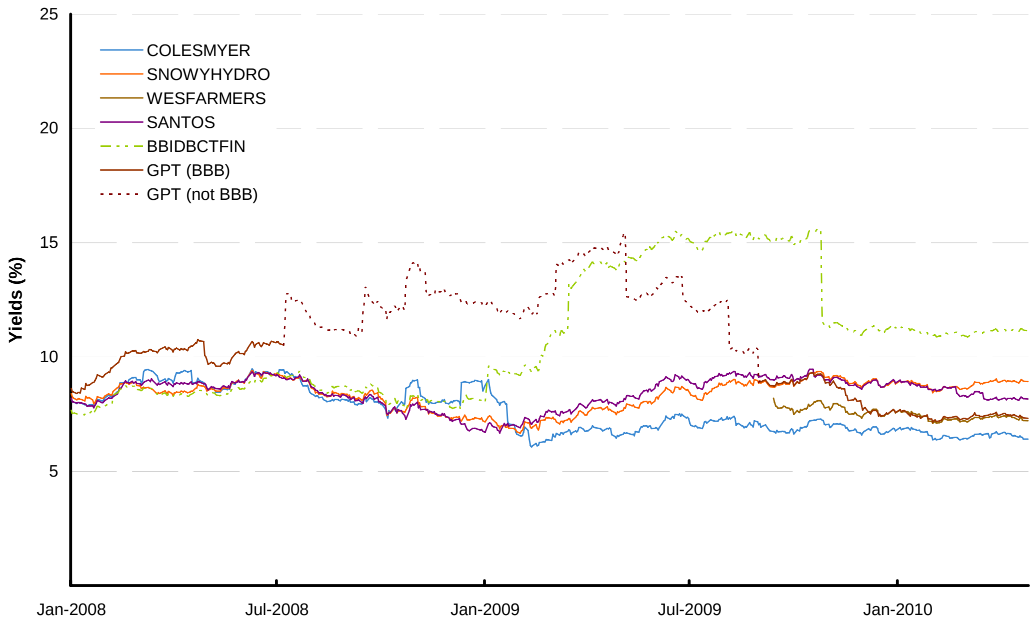
689 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates, A report for ETSA Utilities*, January 2010, pp. 16–18.

690 AER, *Final decision, Access Arrangement proposal, Wagga Wagga natural gas distribution network, 1 July 2010–30 June 2015*, March 2010, pp. 31–43.

691 CEG, *Testing the accuracy of Bloomberg vs CBASpectrum fair value estimates, A report for ETSA Utilities*, January 2010, pp. 15–16.

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 11.2: Yields on the population of BBB+ bonds—UBS



Source: UBS, Rate sheets 1 January 2007–23 April 2010.

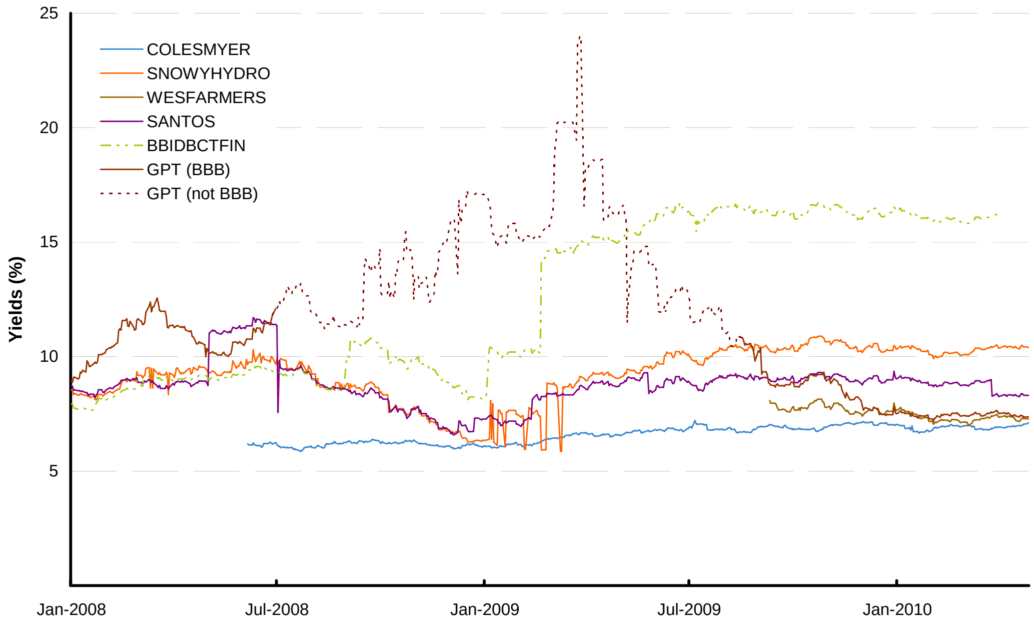
As shown in figure 11.2, based on data from UBS, the average observed yield for the BBI bond was around 7.5 per cent between January 2007 and December 2008. This increased significantly to around 13 per cent between December 2008 and March 2009. Based on this initial inspection, the Chow test on the 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.[692]

Using the augmentations to the AER’s standard methodology as suggested by CEG, the 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 11.3. 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.

[692] Babcock and Brown, *Suspension from official quotation*, 12 January 2009.

Figure 11.3: 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.

Table 11.3: Sample of BBB+ bonds—observed yields and fair values between 29 March and 23 April 2010 (per cent)

Issuer	**Average observed yield**			**Average fair value**	
	Bloomberg	CBASpectrum	UBS	Bloomberg	CBASpectrum
Coles Myer	6.68	6.61	6.59	7.35	7.31
Snowy Hydro	8.69	10.43	8.95	7.60	7.63
GPT	7.52	7.48	7.46	7.82	7.80
Wesfarmers	7.36	7.34	7.36	8.36	8.07
Santos	9.51	8.32	8.18	8.87	8.27

Source: Bloomberg, CBASpectrum, UBS, AER analysis.

Table 11.3 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, 29 March to 23 April 2010.

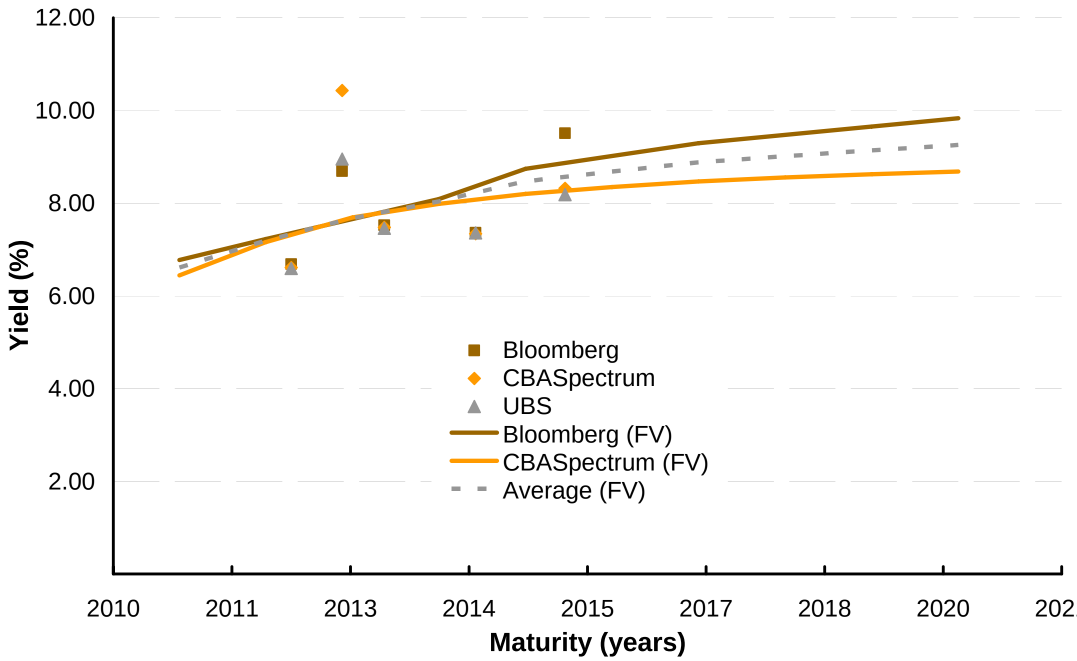
The observed yields were compared to the Bloomberg BBB fair value curve, the CBASpectrum BBB+ fair value curve and an average of the two curves using the weighted sum of squared errors. Table 11.4 and figure 11.4 show the results.

Table 11.4: Fair value and observed yield analysis using weighted sum of squared errors between 29 March and 23 April 2010 (per cent)

		Fair value source		
		Bloomberg	CBASpectrum	Average
Observation source	UBS	0.80	0.58	0.67
	Bloomberg	0.63	0.74	0.66
	CBASpectrum	2.00	1.80	1.88

Source: Bloomberg, CBASpectrum, UBS, AER analysis.

Figure 11.4: Fair value and observed yield analysis based on BBB+ bond sample



Source: Bloomberg, CBASpectrum, UBS, AER analysis.

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.

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 when two of the three data sources are used for the observed bond yields—that is, using data from UBS or CBASpectrum. Bloomberg's BBB+ fair curve best matches observed yields when the data is sourced from Bloomberg. However, since CBASpectrum performs better for the majority of data sources, its fair value curve is considered to provide the best match to observed yields. 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, 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 ETSA Utilities.

The AER determines the benchmark DRP by averaging the yield on a 10–year BBB+ corporate bond over the averaging period of 18 business days between 29 March and 23 April 2010 (to match the period used for estimating the risk–free rate). The resulting DRP is 2.98 per cent (effective annual compounding rate). Adding this DRP to the risk–free rate of 5.89 per cent provides a return on debt of 8.87 per cent.

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.

11.4.4 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.[693] The AER noted that the inflation forecast would be updated using the latest forecasts at the time of the final decision.[694] 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.[695]

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693 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 342–344.
694 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 344.
695 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 344.

ETSA Utilities revised proposal

ETSA Utilities' revised regulatory proposal accepted the draft decision on the methodology for determining the expected inflation rate based on the average of RBA forecasts and targets. However, ETSA Utilities considered it inappropriate for the AER to adopt an entirely different methodology for determining the inflation rate from that set out in the draft decision—that is, to change to using a market based approach in the final decision.[696]

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.[697] The AER confirms its draft decision that the best estimate of expected inflation is represented by the methodology based the average on RBA forecasts and targets, as outlined in the draft decision.[698]

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.[699] As the AER would prefer to use 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 11.5.[700] The methodology used to derive the best estimate of expected inflation is consistent with that outlined in the draft decision and accepted by ETSA Utilities. 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 11.5: 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.

696 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 196.
697 NER, clause 6.4.2(b)(1).
698 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.
699 AOFM, 5 November 2009, viewed 9 March 2010, http://www.aofm.gov.au/content/borrowing/calendar.asp.
700 RBA, *Statement of Monetary Policy*, 4 February 2010, p. 58.

11.4.5 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 NEO.[701] This included consideration of:[702]

- the relevant revenue and pricing principles, including whether the rate of return was sufficient to incentivise efficient investment—but not inefficient overinvestment—in electricity networks
- the links between WACC values and methods, ensuring that appropriate consistency is maintained between components
- the prevailing market conditions, the risk involved in providing regulated services, and the requirement for a forward-looking estimate.

Based on a risk–free rate of 5.37 per cent, the nominal post–tax rate of return on equity was 10.57 per cent, and the overall nominal vanilla WACC was 10.02 per cent. The AER considered that both its approach and these values would contribute, or would be likely to contribute, to the achievement of the NEO.[703]

Submissions

DUET raised concerns that the cost of equity capital benchmarking the AER undertook utilised forecast yields that failed to account for capital growth expectations, leading to material understatement of the true cost of new equity.[704] DUET stated that the observations made by the AER regarding DUET's overseas and unregulated assets do not result in DUET's cost of equity being unrepresentative of Australian regulated entities.[705]

ECCSA submitted that the cost of capital in the draft decision was too high, and stated that submissions to the WACC review from the Major Energy Users group (MEU) had already identified the problems with the SORI WACC parameters.[706] ECCSA referenced a research note from Credit Suisse which referred to the draft decision's WACC as being above market expectations. It considered that the debt risk premium was excessive compared to the actual funding costs for ETSA Utilities.[707]

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 WACC review.[708] In

701 NEL, s. 16(1).
702 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 338–342.
703 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 341–342.
704 DUET, *South Australian draft distribution determination*, 29 January 2010, p. 1.
705 DUET, *South Australian draft distribution determination*, 29 January 2010, p. 3. The DUET submission also included a section titled *The purpose of sector capital raisings in 2008–09*, which was subsequently withdrawn by DUET (Email, *Clarification of letter to the AER*, 12 April).
706 ECCSA, *A response*, February 2010, p. 44.
707 ECCSA, *A response*, February 2010, p. 43.
708 This statement is not referenced to a particular WACC review submission. EUAA, *Submission to the AER on ETSA Utilities*, February 2010, p. 11.

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.[709] Further, the EUAA noted that the UK distribution networks accepted the Ofgem proposals, inferring 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.[710]

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.[711] 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 is likely to contribute, to the achievement of the NEO.[712]

The AER considers that the material submitted to the WACC review—including submissions from various user groups—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.[713]

Comparisons based on forecast yields

DUET submitted:[714]

> The AER benchmarked this return [on equity] against forecast yields for Australian listed regulated energy utility businesses. This is an erroneous measure of the cost of equity as forecast yields fail to account for capital growth expectations inherent in investor's expected returns.

The AER notes that this statement by DUET is inconsistent with its previous submission to the WACC review as a member of the Financial Investor Group (FIG),[715] where it stated:[716]

> One of the key characteristics of mature infrastructure investments is that their returns are yield–dominated…Similarly, most of the investors in listed vehicles are also yield focussed…Given this characteristic, examining the trading yields of infrastructure businesses can provide some useful information about investor expectations.
>
> The FIG considers that the cost of equity for listed investors can currently be estimated by looking at trading yields and applying a discount of at least around 5-10%.

709 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, p. 12.
710 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, p. 12.
711 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 338–339.
712 NEL, s. 16(1).
713 AER, *Final decision, WACC parameters*, May 2009.
714 DUET, *South Australian draft distribution determination*, 29 January 2010, p. 1.
715 FIG, *Submission to the AER's WACC parameter review: The investor perspective*, January 2009, p. 8.
716 FIG, *Submission to the AER's WACC parameter review*, January 2009, pp. 34–35.

In this context, the AER's comparison of the return on equity against forecast yields was neither erroneous nor a benchmarking exercise. The AER incorporated the 'useful information' provided by forecast yields in its assessment of the reasonableness of the return on equity at that point in time, and explicitly differentiated this from a long–term average.[717] Further, the AER noted analyst expectations that there would be no increase in dividends per share in the medium term.[718] Although ETSA Utilities' regulatory proposal claimed that the market return on equity had risen above the SORI parameters as a result of the GFC, in October 2009 the regulated return on equity compared favourably with forecast yields for listed Australian regulated utilities.[719]

The AER clarifies, consistent with its previous statements, that the actual return to equity holders generally includes dividends and capital gains. As discussed above, capital appreciation as opposed to dividend payments is not expected to be a significant source of return for this sector, but it would be theoretically preferable to include expected capital gains in addition to forecast yields, as DUET stated. However, the practical assessment of expected capital gains is difficult. The AER notes that DUET provides no justification for its chosen adjustment for capital gains—the addition of Royal Bank of Scotland figures for 3 year dividend per share growth to the forecast yield.[720] The AER does not consider that this is accurate or appropriate—for instance, the resulting forecast for APA Group implausibly ascribes one third of investor return to capital gains.[721] Further, the AER explicitly noted the need for caution in interpreting dividend yields based on daily share prices when it considered the FIG submission to the WACC review.[722]

In view of the above, the AER places limited weight on the comparison between forecast yields and the rate of return. Nonetheless, the expected return on equity set in this decision (10.84 per cent) is above the mean forecast yield (10.57 per cent) submitted by DUET (as at 1 December 2009).

However, the return on equity set in this decision (11.09 per cent) is below the mean *historical* forecast yield (12.45 per cent) submitted by DUET.[723] The AER notes that there are a number of reasons why this comparison does not indicate that the AER has set the return on equity too low:

- The analysis is over the five years from 2005 to 2009, and performance during this period may not reflect expectations for the upcoming regulatory control period. The AER considers that there are reasonable grounds to conclude that averaging across the last few years of the resources boom (2005 to 2007) and the

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717 AER, *Draft decision, SA draft distribution determination*, 25 November 2009, pp. 342–344.
718 AER *Final decision, WACC parameters*, May 2009, pp. 38–41.
719 AER, *Draft decision, SA draft distribution determination*, 25 November 2009, p. 341.
720 DUET, *South Australian draft distribution determination*, 29 January 2010, p. 2.
721 More specifically, the DUET projection indicates that equity investors will receive 10 per cent dividend yield and an effective 5 per cent return from capital gains for a total return of 15 per cent. See DUET, *South Australian draft distribution determination*, 29 January 2010, p. 2 (exhibit 2).
722 AER *Final decision, WACC parameters*, May 2009, pp. 38–41.
723 DUET, *South Australian draft distribution determination*, 29 January 2010, p. 2 (exhibit 2).

global financial crisis (2007 to 2009) will not produce an estimate of return expectations for 2010 to 2015.[724]

- The six businesses in this analysis may have higher rates of return because they undertake unregulated activities. This point is raised separately by DUET in its submission and is considered by the AER below.

The AER considers that caution should also be exercised when evaluating the return on listed businesses that undertake activities beyond the regulated services provided by the benchmark firm. In the draft decision the AER noted:[725]

> …that over 50 per cent of DUET Group's carrying value of investments are either overseas activities or are currently unregulated activities and therefore are likely to attract a higher return on equity than other regulated utilities.

DUET submitted that its ownership of overseas and unregulated assets did not cause investors in DUET to require a higher rate of return relative to the benchmark firm. In effect, DUET contended that the overseas and unregulated assets it owns face the same risk (and therefore provide the same rate of return) as its regulated assets.

The AER considers that DUET fails to address the key reasons from the draft decision regarding the relative rate of return on these assets:

- DUET submitted that its overseas asset (Duquesne Light) is largely regulated,[726] but provided no evidence that a regulated business in the US faces the same risks as a regulated business in Australia.

- DUET submitted that the Dampier to Bunbury Pipeline (DBP) is regulated by the ERA, but simultaneously noted that no shippers will be on regulated tariffs during the next regulatory control period.[727] Further, the primary and founding shipper (Alcoa) will never be on the regulated tariff.

- DUET stated that 'the DBP has a lower operating risk profile than most regulated utility assets'.[728] The AER notes that there are two alternative interpretations of the phrase 'operating risk' used in this context, but considers that neither interpretation supports DUET's argument:

  - It refers to specific risk facing that particular entity, but not the market as a whole. This is irrelevant to the determination of rate of return under the CAPM, since the equity investor eliminates this risk through diversification across many companies.

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724 The AER notes that the review of the rate of return must produce a forward looking rate of return that is commensurate with prevailing conditions in the market for funds, as stated in clause 6.5.4(e) of the NER.

725 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 341.

726 Duquesne Light earns 81 per cent of its revenues in services regulated by the Pennsylvania Public Utilities Commission (PaPUC) and the Federal Energy Regulatory Commission (FERC). See DUET, *South Australian draft distribution determination*, 29 January 2010, p. 3.

727 DUET, *South Australian draft distribution determination*, 29 January 2010, p. 3.

728 DUET, *South Australian draft distribution determination*, 29 January 2010, p. 3.

- It refers to the inherent exposure of the entity's underlying assets to systematic risk affecting the whole market—that is, its asset beta.[729] In the relevant access arrangement, Dampier to Bunbury Natural Gas Pipeline (WA) Transmission Pty Ltd (DBNGP) estimate the asset beta of five comparable gas networks at 0.2, but the asset beta of the DBP at 0.6.[730] That is, according to the DBP service provider, the underlying risk exposure of the network is three times that of comparable networks in Australia.[731] Further, the comparable asset beta resulting from the SORI parameters would be 0.4,[732] so the DBP has significantly higher systematic risk exposure than the benchmark electricity distribution network.[733]

The AER considers that there are grounds for cautious evaluation of observed returns on listed entities, such as DUET, with substantial unregulated or overseas activities. This includes Hastings Diversified Utilities Fund (HDF), which has a substantial stake in a UK water distribution company, South East Water. The AER notes that HDF is the clear outlier on the graph of historical forecast yield submitted by DUET, with a 15.0 per cent yield. If HDF was excluded, the average yield would drop to 11.9 per cent.

International comparisons of the rate of return

The AER notes that in the WACC review it explicitly considered the form of the CAPM (domestic or international).[734] 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.[735] The AER notes that market observations do not support the conclusion that the Australian capital market is fully integrated with international capital markets.[736] 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,[737] and

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729 This statement assumes a CAPM framework; this is the relevant framework for both the DBNGP access arrangement and the current regulatory proposal.

730 DBNGP, *Proposed revised access arrangement information, Dampier to Bunbury natural gas pipeline*, 21 January 2005, p. 9 and DBNGP, *Dampier to Bunbury natural gas pipeline, Submission #4, Reference tariff policy and reference tariff, Public version*, 27 January 2005, pp. 14–16.

731 The Economic Regulation Authority (ERA) approves the WACC resulting from this asset beta, see ERA, *Access arrangement information for the Dampier to Bunbury natural gas pipeline*, 15 December 2005, p. 11.

732 Specifically, if the SORI equity beta of 0.8 was converted using the same formula and debt beta as that adopted by DBNGP in its access arrangement proposal. See DBNGP, *Dampier to Bunbury natural gas pipeline, Submission #4, Reference tariff policy and reference tariff, Public version*, 27 January 2005, p. 14.

733 The AER notes that the DBP is due to submit a revised access arrangement proposal to the ERA in April 2010, so it may correct this inconsistency at this time.

734 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.

735 AER, *Final decision, WACC parameters*, May 2009, pp. 100–101.

736 AER, *Explanatory statement, WACC parameters*, December 2008, p. 53 and AER, *Final decision, WACC parameters*, May 2009, p. 100.

737 NER, clauses 6.5.2 and 6.5.4(e).

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 in for comparable entities in the UK by Ofgem. The AER notes that this paper refers to an asset beta with rather than an equity beta.[738] 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.[739] 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.[740] 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.[741] 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.[742]

The AER considers there are several contentious links in the EUAA's argument that the acceptance of Ofgem's proposals by the UK businesses means that 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 by Mountain and Littlechild).[743] 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).

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 NEO.

11.5 AER conclusion

The AER determines a nominal vanilla WACC of 9.76 per cent for ETSA Utilities as set out in table 11.6. The WACC is based on the updated risk–free rate and DRP, using 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

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738 EUAA, *Submission to the AER on ETSA Utilities*, 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.

739 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).

740 Ofgem, *Electricity Distribution Price Control Review, Final Proposals, Allowed Revenues and Financial Issues*, 7 December 2009, p. 14.

741 AER, *Final decision, WACC parameters*, May 2009, pp. 260–264.

742 AER, *Final decision, WACC parameters*, May 2009, pp. 239–344.

743 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.

parameters are based on the SORI, as there was no persuasive evidence justifying a departure.

Table 11.6: AER conclusion on WACC parameters

Parameter	
Nominal risk–free rate	5.89%
Real risk–free rate	3.28%
Expected inflation rate	2.52%
Gearing level (Debt:Equity)	60:40
Market risk premium	6.5%
Equity beta	0.8
Debt risk premium	2.98%
Nominal pre–tax return on debt	8.87%
Nominal post–tax return on equity	11.09%
Nominal vanilla WACC	9.76%

11.6 AER decision

In accordance with clause 6.12.1(5) of the NER, the rate of return to apply to ETSA Utilities is 9.76 per cent.

12 Service target performance incentive scheme

This chapter discusses the AER's application of its national service target performance incentive scheme (STPIS) to ETSA Utilities in the next regulatory control period.

The STPIS provides incentives for DNSPs to maintain and improve service performance and 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 establishes 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 has two broad components, the s–factor and the Guaranteed Service Levels (GSL) scheme. The s–factor comprises of three components, namely reliability of supply, quality of supply and customer service.

12.1 AER draft decision

The AER approved the use of the Box–Cox transformation method by ETSA Utilities for the purpose of setting the major event day (MED) boundary in the next regulatory control period. However, the AER rejected ETSA Utilities' proposal to apply a modified s–bank mechanism.[744]

The AER determined that the national distribution STPIS would apply to ETSA Utilities in the next regulatory control period in the following form:[745]

- the applicable components and parameters are the system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) reliability of supply parameters and the telephone answering customer service parameter
- the quality of supply parameter, the momentary average interruption frequency index (MAIFI), would not be applied as the sampling method used in ETSA Utilities' reporting of MAIFI was not a suitable basis of performance measurement for the STPIS
- overall revenue at risk of ±3 per cent including ±0.3 per cent for the telephone answering parameter
- the incentive rates to apply to each applicable parameter are set out in table 12.1
- the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period are set out table 12.2

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[744] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 367.
[745] AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 366–367.

- the GSL component would not apply while ESCOSA's GSL scheme remained in place. In the event that the ESCOSA's GSL scheme is withdrawn the AER would implement such a scheme from the day the jurisdictional scheme is withdrawn.

Table 12.1: AER draft decision on ETSA Utilities incentive rates

Parameter	Incentive rate
Reliability of supply component	
SAIDI	
CBD	0.0099
Urban	0.0550
Short-rural	0.0100
Long-rural	0.0123
SAIFI	
CBD	0.9018
Urban	4.5787
Short-rural	1.1577
Long-rural	1.7147
Customer service component	
Telephone answering parameter	–0.0400

Source: AER, *Draft decision, SA draft distribution determination*, November 2009, p. 356.

Table 12.2: AER draft decision on ETSA Utilities performance targets

		Targets				
Parameter	**Unit**	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
SAIDI						
CBD	minutes	27.1	27.1	27.1	27.1	27.1
Urban	minutes	104.4	104.4	104.4	104.4	104.4
Short rural	minutes	184.0	184.0	184.0	184.0	184.0
Long rural	minutes	270.2	270.2	270.2	270.2	270.2
SAIFI						
CBD	per 0.01 interruptions	0.263	0.263	0.263	0.263	0.263
Urban	per 0.01 interruptions	1.292	1.292	1.292	1.292	1.292
Short rural	per 0.01 interruptions	1.736	1.736	1.736	1.736	1.736
Long rural	per 0.01 interruptions	2.111	2.111	2.111	2.111	2.111
Customer service						
Telephone answering	percentage	88.7	88.7	88.7	88.7	88.7

Source: AER, *Draft decision, SA draft distribution determination*, November 2009, p. 366.

12.2 Revised regulatory proposal

ETSA Utilities considered the STPIS performance targets should be determined using the same period as that used to establish the ESCOSA's jurisdictional targets. This was considered by ETSA Utilities likely to be a period of five years.[746]

ETSA Utilities also sought clarification that the data used to establish performance targets for the telephone answering parameter excluded MED telephone response performance.[747]

12.3 Submissions

The Energy Consumers Coalition of South Australia (ECCSA) submitted the AER proposes to increase ETSA Utilities' capex and opex allowances with the average tariff to rise by 20 per cent, but there was no improvement in service standards.[748]

ECCSA stated the AER should reassess whether there is a general acceptance that consumers will pay more for better service.[749]

ECCSA also stated the draft decision is insufficiently challenging and the performance targets need to be set so that ETSA Utilities has to continue to achieve against its recent performance rather than the average of the last four years. It submitted that more challenging performance targets should be used as ETSA Utilities has been granted significant increases in opex and capex.[750]

12.4 Issues and AER considerations

12.4.1 Alternative methodology for performance targets

Revised regulatory proposal

ETSA Utilities stated ESCOSA is likely to issue its final decision on the Electricity Service Standards for 2010 to 2015 in April 2010. It indicated that performance targets under ESCOSA's scheme are likely to be based on five years of data (this would require using data from the yet to be completed 2009–10 regulatory year). ETSA Utilties was concerned that there would be a disconnect between the ESCOSA's jurisdictional service standards and the STPIS targets.[751]

ETSA Utilities proposed the STPIS should be consistent with ESCOSA's scheme. On the basis that ESCOSA adopts an approach of using five years of data, ETSA Utilities proposed the STPIS performance targets should also be based on five years data (including 2009–10 data).[752]

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746 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 168.
747 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 168.
748 ECCSA, *A response*, February 2010, p. 39.
749 ECCSA, *A response*, February 2010, p. 40.
750 ECCSA, *A response*, February 2010, p. 42.
751 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 168.
752 ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 167–168.

Consultant advice

PB considered that an alternative methodology would only be appropriate if it was consistent with all aspects of the STPIS. As ETSA Utilities' alternative methodology does not allow the AER to include targets in the distribution determination, PB considered that it was inconsistent with the STPIS and therefore not appropriate.[753]

AER considerations

The AER developed a national STPIS involving considerable consultation and intends to apply the scheme to all DNSPs in the NEM.

Clause 3.2.1(a) of the STPIS requires the AER to set performance targets based on average performance over the past five regulatory years which concludes with data from 2008–09. ETSA Utilities proposed that the AER use 2009–10 data. Therefore, ETSA Utilities' proposal would require the AER to consider an alternative methodology.

Clause 3.2.1(c) of the STPIS provides the AER with discretion to approve a performance target based on an alternative methodology where the AER considers that the performance target derived from the alternative methodology satisfies the objectives set out at clause 1.5 of the STPIS.

The key consideration is whether the AER can use the five years of data that the ESCOSA intends to rely on for the purposes of the STPIS.

The AER considers it appropriate to be as consistent with the ESCOSA service standards scheme as allowed by the STPIS. As noted in the draft decision, the AER considers that ETSA Utilities does not have five years of suitable data available to establish performance targets because of the change from a manual reporting system to an outage management system. The earliest suitable data that ETSA Utilities has is from 2005–06.[754] For these reasons, in the draft decision, the AER set targets based on four years of data.[755]

ETSA Utilities' proposal to use five years of data will require the AER to use 2009–10 data. However, the AER has not been able to assess whether this data and targets satisfy the objectives set out at clause 1.5 of the STPIS as it is not available at the time of making this decision and will not be available until after the next regulatory control period commences. Accordingly, and as noted by PB, this means the AER would not be able to determine performance targets until after the commencement of the next regulatory control period if ETSA Utilities' alternative methodology was accepted. To do so:

- is inconsistent with how chapter 6 of the NER contemplates the AER is to apply the STPIS in a distribution determination
- requires the AER to reopen the distribution determination at some stage during the next regulatory control period to take into account the 2009–10 data. Chapter 6 of

753 PB, *Review of ETSA Utilities' revised regulatory proposal, March 2010*, p. 43.
754 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 365.
755 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 365.

the NER does not provide for a distribution determination to be reopened for this reason

- is inconsistent with the intent of Version 01.1 of the STPIS that performance targets must be provided in the distribution determination.[756]

The AER also has not had the opportunity to review or consult on the 2009–10 data for the purposes of this decision.

AER conclusions

The AER concludes that, for the reasons discussed above, it is not appropriate to use ETSA Utilities' alternative methodology and maintains its position to set targets based on four years of data, from 2005–06 to 2008–09.

12.4.2 Telephone answering parameter

ETSA Utilities sought clarification that it excluded MEDs when calculating performance targets for the telephone answering parameter.[757]

PB confirmed ETSA Utilities removed MEDs from the calculation of average performance on which targets are based. PB considered this approach is consistent with clause 5.4 of the STPIS, which allows MEDs to be excluded for the purpose of setting performance targets for the telephone answering parameter.[758]

The AER considers ETSA Utilities' proposed approach is consistent with the STPIS.

12.4.3 Other issues

ECCSA submitted the AER proposes to increase ETSA Utilities' capex and opex allowances, resulting in tariff increases, without any improvement in service standards.[759]

The AER previously noted ETSA Utilities did not propose any expenditure for the purpose of improving service performance as measured by the STPIS.[760] If the AER's decision did provide any expenditure which would result in improvements in service performance as measured by the STPIS, the AER would be required to adjust the performance targets to make the targets more onerous.[761] This reflects that under the STPIS, DNSPs should only be rewarded under the STPIS for improvements in efficiency. DNSPs do not receive financial rewards under the STPIS for improved service performance where this improvement is a result of increased expenditure allowances.

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756 The AER clarified this intent in version 01.2 of the STPIS by including clause 2.1(d)(4) which states that the AER will stipulate the performance target to apply to each applicable parameter in each regulatory year of the regulatory control period. AER, *Explanatory statement, proposed amendment, Service target performance incentive scheme, Electricity distribution network service providers,* September 2009, pp. 12–13.

757 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 168.

758 PB, *Review of ETSA Utilities' revised regulatory proposal*, April 2010, p. 43.

759 ECCSA, *A response*, February 2010, p. 39.

760 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 352.

761 AER, *Final decision, Electricity distribution network service providers, Service target performance incentive scheme,* November 2009, clause 3.2.1(a)(1A).

The AER notes that the increased expenditure allowances provided to ETSA Utilities result from various factors, including the need to augment South Australia's electricity distribution network due to continuing economic growth, growth in population and energy use per customer, and real increases in the cost of labour and materials (see chapters 7 and 8 of this decision).

Accordingly, the AER considers that the approved expenditures will not correspond to improvements in service performance as measured by the STPIS. However, the STPIS does provide incentives for the DNSP to maintain and improve service performance through improved efficiency.

Willingness to pay

ECCSA submitted the AER should reassess whether there is a general acceptance that consumers will pay more for better service.[762]

In developing the STPIS the AER considered the 2008 Charles River Associates (CRA) Report and was satisfied that this was a robust study of customers' willingness to pay. The AER was satisfied that the value of customer reliability set out in the CRA Report reflects customers' willingness to pay.[763]

The incentive rates in the STPIS are based on the value of customer reliability. The AER is therefore satisfied that the STPIS takes account of customers' willingness to pay for improved service.

Performance targets

ECCSA stated the performance targets need to be set so that ETSA Utilities continues to achieve against its recent performance rather than the average of the last four years.[764]

The STPIS will only reward ETSA Utilities if its actual service performance exceeds its performance targets. The performance targets are usually based on the average of the last five years of data. However, for the reasons discussed earlier in this chapter, for the purpose of the next regulatory control period ETSA Utilities' performance targets will be based on the average of the last four years.

The benefit of using an average of performance instead of the most recent performance is that it limits the effect of the variability in performance that occurs due to factors that are not within the control of the DNSP. If the AER were to base performance targets on the final year of the regulatory control period then it must do so consistently. If the DNSP's performance is poor in the final year, for whatever reason, the DNSP's performance targets for the STPIS would be less onerous on the DNSP. Moreover, using the average rather than the most recent performance removes any incentive that the DNSP may have to underperform in the final year of a regulatory control period to make future targets easier.

[762] ECCSA, *A response*, February 2010, p. 40.
[763] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 355.
[764] ECCSA, *A response*, February 2010, p. 42.

Accordingly, the AER will continue to use an average of past performance to determine performance targets for the ETSA Utilities in the next regulatory control period.

12.5 AER conclusion

The AER confirms its draft decision to apply the STPIS to ETSA Utilities. The AER will apply the SAIDI and SAIFI reliability of supply parameters and the telephone answering customer service parameter. There are no quality of supply parameters to apply. The components and parameters of the STPIS applicable to ETSA Utilities are set out at table 12.3.

Table 12.3: AER decision – STPIS parameters for ETSA Utilities

Component	Network segment
Reliability of supply	
SAIDI	CBD feeders
	Urban feeders
	Short rural feeders
	Long rural feeders
SAIFI	CBD feeders
	Urban feeders
	Short rural feeders
	Long rural feeders
Customer service	
Telephone answering	All of network

The AER confirms that it will apply the same performance targets to ETSA Utilities as those set out in the draft decision. The performance targets are shown at table 12.4.

Table 12.4 AER performance targets for ETSA Utilities

		Targets				
Parameter	**Unit**	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
SAIDI						
CBD	minutes	27.1	27.1	27.1	27.1	27.1
Urban	minutes	104.4	104.4	104.4	104.4	104.4
Short rural	minutes	184.0	184.0	184.0	184.0	184.0
Long rural	minutes	270.2	270.2	270.2	270.2	270.2
SAIFI						
CBD	per 0.01 interruptions	0.263	0.263	0.263	0.263	0.263
Urban	per 0.01 interruptions	1.292	1.292	1.292	1.292	1.292
Short rural	per 0.01 interruptions	1.736	1.736	1.736	1.736	1.736
Long rural	per 0.01 interruptions	2.111	2.111	2.111	2.111	2.111
Customer service						
Telephone answering	percentage	88.7	88.7	88.7	88.7	88.7

The AER also updated the incentive rates to apply to ETSA Utilities to allow for the amended revenues in this decision. The AER will apply the incentive rates which are set out at table 12.5.

Table 12.5: AER conclusion on incentive rates for ETSA Utilities incentive rates

Parameter	**Incentive rate**
Reliability of supply component	
SAIDI	
CBD	0.0092
Urban	0.0513
Short-rural	0.0094
Long-rural	0.0115
SAIFI	
CBD	0.8410
Urban	4.2701
Short-rural	1.0797
Long-rural	1.5992
Customer service component	
Telephone answering parameter	–0.0400

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 ETSA Utilities 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 and the telephone answering customer service parameter as set out at table 12.3 of this decision
2. overall revenue at risk of ±3 per cent, including ±0.3 per cent for the telephone answering parameter
3. the incentive rates to apply to each applicable parameter will be calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of the STPIS, and are set out in table 12.5 of this decision
4. the performance targets to apply to each applicable parameter in each regulatory year of the next regulatory control period are set out in table 12.4 of this decision
5. the GSL component will not apply while ESCOSA’s GSL scheme remains in place. In the event that ESCOSA’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 application of the STPIS to apply to ETSA Utilities 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 ETSA Utilities. An 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 would be to apply the national EBSS to ETSA Utilities in the next regulatory control period.[765] However, the scheme will not have a direct financial impact on ETSA Utilities until the regulatory control period commencing 1 July 2015 when it will receive carryover benefits/penalties for efficiency gains or losses made during the next regulatory control period.

13.1 AER draft decision

The AER decided it will apply the EBSS in accordance with the framework and approach for ETSA Utilities in the next regulatory control period. The AER considered that it would not adjust the EBSS for the consequences of changes in demand growth for ETSA Utilities for 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:

- debt raising costs
- insurance and self insurance costs
- superannuation costs for defined benefits and retirement schemes
- the demand management innovation allowance (DMIA)
- other specific uncontrollable costs incurred and reported by ETSA Utilities 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.

The AER reviewed the transitional arrangements in the NER which require it to observe the ESCOSA's Statement of Regulatory Intent (ESCOSA SORI) in relation to the treatment of negative carryover amounts from ESCOSA's Efficiency Carryover Mechanism (ECM). The AER decided to allow negative opex carryover accrued in respect of the ECM to be deferred to offset any positive carryover accrued in the next regulatory control period, provided the negative carryover is accrued in an approved uncontrollable opex cost category under the EBSS.

No submissions were received on this issue.

765 AER, *Final decision, Framework and approach paper, ETSA Utilities 2010–15*, November 2008.

13.2 Revised regulatory proposal

In relation to the efficiency carryover arising from the ECM for the current regulatory control period, ETSA Utilities revised the total of the capex and opex 'out turn' values.[766] The opex out turn values have been adjusted as follows:

- sponsorship costs are excluded from actual opex, as ESCOSA provided no allowance for this cost in its determination of the opex allowance in the *2005–2010 Electricity Distribution Price determination* (EDPD)
- actual costs for the 2009 regulatory year replace the forecast costs in its original proposal.

The impact of these adjustments is a net reduction of $1.4 million in opex out turn carryover for the next regulatory control period, resulting in an opex carryover of –$35.9 million.

The capex out turn values have been adjusted to reflect actual costs for the 2009 regulatory year rather than the forecast costs in its original proposal. The impact of this revision is an overall net increase of $0.9 million in capex out turn carryover for the next regulatory control period, resulting in a capex carryover of $20.5 million.

ETSA Utilities maintained its original proposal in relation to the arrangements regarding the transition from ESCOSA's ECM to the EBSS. In particular, ETSA Utilities considered the aspects of the ESCOSA SORI which include uncontrollable cost items within the EBSS and which apply a negative carryover amount, either immediately or on a deferred basis, are incorrect or invalid.[767] ETSA Utilities stated the AER should:[768]

- exclude uncontrollable cost items arising in the current regulatory control period from the carryover amount
- disregard any negative carryover amounts for the next regulatory control period which result from costs arising in the current regulatory control period.

13.3 Issues and AER considerations

13.4.1 Application of the Efficiency Carryover Mechanism

Clause 9.29.5(c) of the NER provides that the AER's application of an EBSS to ETSA Utilities for the next regulatory control period must be consistent with the ESCOSA SORI.[769] The ESCOSA SORI contains transitional arrangements relating to the ECM that applied to ETSA Utilities in the current regulatory control period.[770]

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766 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 173.
767 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 174.
768 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 175.
769 Clause 7.4 of the *Electricity Pricing Order* (EPO) allows ESCOSA to publish a statement of regulatory intent which sets out how ESCOSA intends to exercise its powers under chapter 7 of the EPO.
770 ESCOSA, *Statement of Regulatory Intent*, March 2007.

AER draft decision

The AER recognised both capex and opex carryovers accumulated under the ECM administered by ESCOSA in the current regulatory control period. The AER determined that:

- each opex annual carryover amount will be calculated and applied in the opex building block determination for the next regulatory control period
- the capex carryover amount will be applied as an adjustment to ETSA Utilities' revenue in the next regulatory control period
- calculation of efficiency gains or losses in the final year (year five) of the current regulatory control period will be in accordance with the ECM.

The AER incorporated both negative and positive carryover amounts accrued in any year of the current regulatory control period into forecast opex amounts for the next regulatory control period. The AER concluded that it will exercise its discretion to defer a net negative opex carryover with regard to whether the accumulated negative carryover:[771]

> 1. was accrued, in whole or in part:
>
>   a. in an opex category that is excluded by the EBSS but not by the ECM, or
>
>   b. in an opex category that is an approved uncontrollable cost category under the EBSS in ETSA Utilities' distribution determination for the next regulatory control period; and
>
> 2. is material in the sense that it is likely to have a significant and undesirable impact on the stability of prices.

The exclusion of capex from the EBSS means that the option of deferring a negative capex carryover amount accumulated under ESCOSA's ECM is not available.

Revised regulatory proposal

ETSA Utilities considered the aspects of ESCOSA SORI which include uncontrollable cost items within the EBSS and which apply a negative carryover amount, either immediately or on a deferred basis, to be incorrect or invalid. ETSA Utilities remained of the view that:[772]

- the ESCOSA SORI should be read down to exclude uncontrollable cost items when calculating the carryover; and
- any negative carryover amount which might result should be disregarded.

ETSA Utilities suggested that this can be achieved by a contextual reading down of the entire ESCOSA SORI such that the AER's application of the EBSS is to be

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[771] AER, *Final framework and approach paper*, *ETSA Utilities*, November 2008, p. 88.
[772] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 174.

consistent with the ESCOSA SORI only to the extent that the ESCOSA SORI was supported by the national electricity code and the South Australian Electricity Pricing Order (EPO). Further, ETSA Utilities stated its desired result can be achieved by striking out the incorrect or invalid paragraph 4 of the ESCOSA SORI.[773]

ETSA Utilities reiterated that due to the absence of negative language in the national electricity code and the EPO, ESCOSA's intention to carry forward any negative amount arising from the current regulatory control period was not supported by legislative authority.[774] ETSA Utilities also expressed its concern that the ECM could result in a significant negative carryover resulting not from inefficiency but from adverse movements in uncontrollable costs.[775]

ETSA Utilities did not consider that the AER appropriately considered or adequately addressed its submissions in relation to the treatment of negative efficiency carryovers during the transition from ESCOSA's ECM to the EBSS.[776]

AER considerations

The AER considered ETSA Utilities' proposal that the ESCOSA SORI be read to exclude uncontrollable cost items when calculating the carryover and any negative carryover amount which might result should be disregarded. The AER's draft decision was not to accept ETSA Utilities' proposal that any negative carryover amounts arising from uncontrollable cost categories should be deferred and applied against future opex efficiency gains. The basis for the draft decision was:[777]

- the potential to offset negative amounts against future positive amounts would dilute the incentives for DNSPs to continually reduce opex
- an accrued net negative carryover may incentivise DNSPs to artificially shift costs into the benchmark year to increase future opex forecasts, as the negative carryover amount calculated in the benchmark year will not be applied until a sufficiently large positive carryover amount is calculated in the following regulatory control period
- a banking mechanism becomes problematic when negative carryovers are accrued consistently in each year of a regulatory control period as the opportunity to offset the negative carryovers against future positive amounts is diminished.

In addition, the AER is cognisant of the requirements of clause 9.29.5(c) of the NER that the EBSS must be consistent with the ESCOSA SORI. It is the AER's view that if it were to strike out paragraph 4 of the ESCOSA SORI, as proposed by ETSA Utilities, its actions would not be consistent with the requirements of clause 9.29.5(c) of the NER. The ESCOSA SORI requires the AER to:[778]

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773 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 174.
774 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 174.
775 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 174.
776 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 174.
777 AER, *Draft decision, South Australia draft distribution determination*, November 2009, p. 377.
778 ESCOSA, *Statement of Regulatory Intent*, March 2007.

- carry forward any net negative efficiency amount calculated for ETSA Utilities for the current regulatory control period into the next regulatory control period

- have discretion to either apply immediately a negative efficiency amount calculated under the current regulatory control period efficiency carryover mechanism, or to defer a negative efficiency amount to offset any future positive efficiency amount.

Notwithstanding ETSA Utilities' submission that the ESCOSA SORI is incorrect or invalid insofar as it applied a negative carryover, it is the AER's view that the NER imposes a valid legal requirement that the EBSS—specified in the distribution determination for ETSA Utilities for the next regulatory control period—must be consistent with the ESCOSA SORI. The AER considers that the intention of the NER is that the AER should give effect to all of the provisions in the ESCOSA SORI, including paragraph 4. Therefore a negative carryover amount arising during the current regulatory control period for ETSA Utilities cannot be disregarded.

Regarding ETSA Utilities' submission that the aspect of the ESCOSA SORI which include uncontrollable cost items was incorrect or invalid, the AER considers that ESCOSA's decision of including uncontrollable cost items in transitional arrangements relating to the ECM has become a legal requirement by operation of clause 9.29.5(c) of the NER. Therefore, uncontrollable cost items not excluded under ESCOSA's ECM cannot be excluded when calculating the carryover amounts for ETSA Utilities arising from the current regulatory control period.

13.4 AER conclusion

In the next regulatory control period the AER will apply the EBSS in accordance with its framework and approach for ETSA Utilities.[779] In accordance with the draft decision, the AER will allow any negative opex carryover accrued in respect of the ECM in the current regulatory control period to be deferred to offset any positive carryover accrued in the next regulatory control period, provided the negative carryover is accrued in an approved uncontrollable cost category under the EBSS.

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 ETSA Utilities during the next regulatory control period, which the AER considers should be excluded

[779] AER, *Final framework and approach paper, ETSA Utilities*, November 2008.

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 is one that satisfies the relevant materiality threshold and is approved by the AER.

Based on ETSA Utilities' revised proposal, the AER's conclusion on controllable opex for ETSA Utilities' EBSS is outlined in table 13.1. This forecast will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[780]

Table 13.1: AER conclusion on ETSA Utilities forecast controllable opex for EBSS purposes ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Total forecast opex	193.2	199.4	205.9	214.9	219.5
Adjustment for debt raising costs	1.5	1.6	1.7	1.7	1.8
Adjustment for self insurance costs	1.2	1.2	1.2	1.2	1.3
Adjustment for insurance costs	2.3	2.5	2.7	2.9	3.0
Adjustment for DMIA	0.6	0.6	0.6	0.6	0.6
Adjustment for superannuation costs	6.8	6.8	6.9	7.0	7.1
Adjustment for non–network alternatives	0.7	0.7	0.7	0.7	0.7
Adjustment for opex carry over[a]	0.6	–15.2	–20.5	–0.8	0.0
Total opex for EBSS purposes	179.5	201.2	212.6	201.6	205.0

Note: Totals may not add due to rounding.
(a) ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 173.

The AER has reviewed ETSA Utilities' revised regulatory proposal and considers the capex carryover is in accordance with the draft decision. The impact of the capex carryover from the current regulatory control period for the next regulatory control period is outlined in table 13.2.

780 AER, *Final decision*, *Electricity DNSPs EBSS*, June 2008, pp. 5–7.

Table 13.2: AER conclusion on revenue adjustment for capex carryover from the current regulatory control period ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Adjustment for capex carryover	8.4	7.5	4.2	0.4	0.0

13.5 AER decision

In accordance with clause 6.3.2(a)(3) of the NER, the application of the EBSS to apply to ETSA Utilities is as specified in section 13.4 of this decision.

In accordance with clause 6.12.1(9) of the NER, the EBSS to apply to ETSA Utilities is as set out in the AER’s *Final decision, Framework and approach paper, ETSA Utilities 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 ETSA Utilities 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 throughs events. Any negative opex carryover accrued under the current regulatory control period *Efficiency Carryover Mechanism* can be deferred to offset any positive carryover accrued in the next regulatory control period, provided the negative carryover is accrued in an approved uncontrollable opex category under the EBSS.

14 Demand management incentive scheme

This chapter sets out the demand management incentive scheme (DMIS) to apply to ETSA Utilities 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.[781]

This chapter reviews the issues raised in response to the AER's draft determination and sets out the AER's considerations on how the DMIS will apply to ETSA Utilities in the next regulatory control period.

14.1 AER draft decision

The AER decided it will apply a two part DMIS to ETSA Utilities. The DMIS will comprise of a Part A – demand management innovation allowance (DMIA) component, and a Part B – foregone revenue component. Part A will be capped at $3 million in the next regulatory control period. The capped amount will be allocated to ETSA Utilities as an ex–ante allowance, in five equal annual instalments of $600 000. The ex–post review and operation of the DMIA will be as set out in the DMIS.[782]

Part B is as set out in the DMIS and remains uncapped for projects approved in Part A.[783]

14.2 Revised regulatory proposal

ETSA Utilities reiterated its proposal that the scope of the DMIS be broadened via amendments to both the Part A – DMIA and the Part B – foregone revenue components.[784]

14.2.1 DMIA

Assessment criteria

ETSA Utilities proposed that the DMIA assessment criteria be modified to include a statement that projects submitted for approval would not be disallowed in the ex–post review should they not achieve the intended demand reduction or not do so in a timely manner.[785] It stated that there is scope for the AER to disallow projects that did not

[781] AER, *Final framework and approach paper, ETSA Utilities*, November 2008, p. 89.
[782] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 390.
[783] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 390.
[784] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 161.
[785] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 161.

perform as intended. In particular it cited section 3.1.3 of the DMIS paper which refers to 'potentially efficient' demand management.[786]

Capped amount

While not proposing to alter the DMIA's capped amount of $3 million, ETSA Utilities stated that this cap is too low, and that the AER should take this into account when considering its proposed treatment of the Part B – foregone revenue component.[787] It stated that the AEMC has suggested the extension of the DMIA to include the connection of embedded generation and that the DMIA will not provide for the funding of many embedded generator connections.[788]

14.2.2 Recovery of foregone revenue

ETSA Utilities proposed that the Part B – foregone revenue component be expanded to apply to any additional demand management project it undertakes in the next regulatory control period that does not form part of its revised proposal, whether undertaken within the scope of the DMIA or not.[789] Further, it proposed that the DMIS be varied such that where the Part A cap has been met, projects can still be approved under Part A of the DMIS for the purposes of recovering foregone revenue in Part B of the DMIS.

In support of its proposal to broaden Part B, ETSA Utilities cited a number of disincentives to the uptake of demand management within the broader regulatory framework.[790]

Interactions between demand management and incentive schemes

ETSA Utilities contended that the AER's statements in the draft decision that the primary sources of recovery of demand management expenditure are through the capex and opex allowances of the determination, failed to recognise that:[791]

- the rate of return on capex projects is established for projects having a low risk profile, equivalent to the 'tried and true' network augmentation alternative. Demand management alternatives have a higher risk profile associated with both their cost structure and the potential that they may not deliver sufficient demand reduction or do so in a timely manner

- in many instances demand management projects will involve a trade off as the deferral of capex will generally require additional opex to be incurred. The regulatory incentives which the AER has set up for capex and opex are not equivalent

- the distributor does not have access to benefits accruing to other industry sectors such as TNSPs, generators and retailers.

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786 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 160.
787 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 158.
788 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 158.
789 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 161.
790 ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 159–160.
791 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 159.

Further, ETSA Utilities stated that the AER's Service Target Performance Incentive Scheme (STPIS) serves to increase the potential cost and risk associated with demand management as it would face financial penalties if a demand management project failed to perform as expected given that such events are not excluded.[792]

Effect of control mechanism on demand management

ETSA Utilities stated that the reduced sales volume which accompanies a demand reduction arising from a successful demand management project is a disincentive to DNSPs under a weighted average price cap (WAPC) but not for those under a revenue cap.[793] It noted that the AER's framework and approach paper included a statement to this effect in its reasoning for why the Part B – foregone revenue component was applied to DNSPs under a WAPC form of control.[794]

14.3 Submissions

The AER received submissions from the South Australian Council of Social Service (SACOSS), the Total Environment Centre (TEC) and UnitingCare Australia (UnitingCare), commenting on the DMIS and demand management more broadly.

SACOSS

SACOSS submitted that ETSA Utilities failed to prioritise peak demand management and that this fails consumers and the National Electricity Objective. It stated that the declining utilisation of expensive infrastructure is testament to this.[795]

SACOSS contended that ETSA Utilities' direct load control (DLC) trials in the current regulatory control period represent a means of progressing demand management.[796] It urged a formal review of the benefits of ETSA Utilities' trials over the current regulatory control period.[797] It also stated that there is evidence on the importance of education about air conditioner maintenance, and asserted that while existing arrangements ensure that ETSA Utilities considers individual demand management projects when considering a specific network upgrade, these do not ensure the provision of ongoing, broader reaching programs that deliver long–term consumer benefits.[798] SACOSS stated that the AEMC and AER needed to support DLC and demand management in general.[799]

SACOSS suggested that the AEMC's review of demand–side participation supports its view that the DMIA's capped amount of $3 million seems arbitrary, and that consumers may be better off in the long–term if network owners were able to take on more expenditure and risk in respect of innovation. It submitted that it hopes that the

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792 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 160.
793 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 159.
794 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 159.
795 SACOSS, *Submission to the AER*, February 2010, p. 8.
796 SACOSS, *Submission to the AER*, February 2010, p. 9.
797 SACOSS, *Submission to the AER*, February 2010, p. 8.
798 SACOSS, *Submission to the AER*, February 2010, p. 8.
799 SACOSS, *Submission to the AER*, February 2010, p. 9.

subsequent rule changes proposed in the AEMC's review will lead to a more effective response to South Australia's peak demand issues.[800]

TEC

The TEC submitted that the AER, MCE and AEMC have all failed to implement a regulatory framework that prioritises demand management above inefficient network expansion.[801] It submitted that ETSA Utilities underutilised demand management, instead opting for peak driven network expansion, and this is inefficient and irresponsible in the context of unnecessary electricity price increases and Australia's rising greenhouse emissions.[802]

The TEC submitted that demand management is by far the most cost effective approach, claiming that it is almost four times more cost effective than network augmentation. Further, it stated demand management's cost effectiveness is further enhanced when compared to the carbon costs payable to consumers that will continue to rise particularly after the introduction of a carbon price in Australia.[803]

The TEC submitted that the DMIA's capped amount is low and neglected the AER's responsibility to ensure that a monopoly network is regulated for efficiency. It stated that this amount is too low compared to ESCOSA's $20 million demand management fund in the current regulatory control period, and that it does not understand why the AER is not intending to build on this work. It stated 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 network businesses.[804]

UnitingCare

UnitingCare submitted that the demand management expenditure for ETSA Utilities, Ergon and Energex across the next regulatory control period, jointly amounted to only $13 million and was miserly compared to the expected revenues for these DNSPS. For ETSA Utilities, it stated that only $3 million would be spent on demand management, compared to its expected revenue of approximately $3.5 billion.[805]

While recognising that there is no established benchmark for demand management expenditure as a percentage of revenue, UnitingCare submitted there are very few successful billion dollar businesses that would have a research and development (R&D) budget below one per cent of revenue. It submitted that demand management should be regarded as the most important R&D matter for DNSPs.[806]

UnitingCare proposed the demand management 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.

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800 SACOSS, *Submission to the AER*, February 2010, pp. 7–8.
801 TEC, *Submission to the AER*, February 2010, p. 2.
802 TEC, *Submission to the AER*, February 2010, p. 2.
803 TEC, *Submission to the AER*, February 2010, p. 2.
804 TEC, *Submission to the AER*, February 2010, p. 2.
805 UCW, *Submission to the AER*, February 2010, p. 10.
806 UCW, *Submission to the AER*, February 2010, p. 10.

Further, UnitingCare suggested that DNSPs should submit their demand management strategies to the AER for approval and have their implementation audited annually.

14.4 Issues and AER considerations

14.4.1 Part A – DMIA

14.4.1.1 Assessment criteria

The AER notes ETSA Utilities' reiteration of its concerns regarding the ex–post review of projects under the Part A – DMIA component and its proposal for inclusion of a statement to the effect that a project would not be disallowed should it not achieve the intended demand reduction or not do so in a timely manner.

While the AER notes that the DMIA assessment criteria do make reference to efficient demand management, this criterion must be considered in the broader context of the DMIS.[807] The DMIA focuses on promoting innovation, capacity and capability in the area of demand management and inherently recognises that developing innovative solutions is accompanied by a degree of risk to the DNSP. Unlike the capex and opex assessment process, the DMIA assessment does not consider whether a project will successfully reduce demand or defer expenditure, and therefore the ex–post approval of expenditure will not be dependent on satisfying such a test. However, the aim of any research and development of innovative approaches that might be pursued under the DMIA is ultimately to develop efficient alternatives to network options in the future, as set out in clause 6.6.3(a) of the NER. It is for this reason that section 3.1.3 of the DMIA refers to the 'exploration of potentially efficient demand management mechanisms'.

As noted in the draft decision, the DMIA assessment criteria are broad but do set some restrictions for funding approval as part of the ex–post review. However, these restrictions exist to ensure that projects for which DMIA funds have been utilised are oriented toward demand management and are not already recovered via any other mechanism including jurisdictional or Commonwealth Government schemes, or recovered through other allowances in the distribution determination.[808]

The AER therefore considers that ETSA Utilities' concerns regarding the ex–post assessment process under the DMIA are effectively addressed by the current wording of the DMIS, that its intended application is clear and no alteration is warranted.

Capped amount

The AER notes that while ETSA Utilities has not proposed altering the DMIA's capped amount of $3 million, it has suggested that this level is too low and would not provide for embedded generation connections. ETSA Utilities requested that the AER take these factors into account in considering ETSA Utilities' proposal to expand the Part B – foregone revenue component.

807 AER, *DMIS – Energex, Ergon Energy and ETSA Utilities*, October 2008, p. 5.
808 AER, *DMIS – Energex, Ergon Energy and ETSA Utilities*, October 2008, pp. 5–6.

In its recent review of demand–side participation in the NEM, the AEMC made recommendations regarding the regulatory framework for connection of embedded generation. In relation to the DMIS, the AEMC recommended that the DMIS in chapter 6 of the NER be amended to become the *Demand management and embedded generation connection incentive scheme*.[809] The recommendation is based on the AEMC's view that there may be a need to provide additional incentives for DNSPs to innovate for the connection of embedded generation.[810] The recommendations are yet to be accepted by the MCE, but were not proposed with the aim of providing a different avenue for funding embedded generator connections, but rather to provide incentives for innovation in respect of these connections. However, the AER notes to the extent that expenditure on innovation in respect of connection of embedded generators is undertaken for demand management purposes, the expenditure would currently already be consistent with the DMIS and therefore approved.

The AER notes the AEMC also highlighted that a key potential barrier to connection of embedded generation in the NEM appears to relate to issues of possible subjectivity in regard to technical standards. The AER considers that this is a separate and distinct matter from the DMIS.

The AER considers neither the DMIA's capped amount or the application of the foregone revenue component need to be altered to account for the AEMC's recommendation that the DMIS specifically include embedded generation.

Issues raised in submissions

The AER notes SACOSS stated that the existing arrangements do not ensure the provision of broader/ongoing demand management projects. To this end, the AER reiterates that the DMIS provides an allowance for expenditure relating to both peak demand management as well as broad based demand management projects. Both types of projects are eligible for DMIA funding, and if approved, foregone revenues as well. While the capex and opex assessment criteria do not explicitly prohibit broad based demand management projects or programs, for expenditure to be approved under these processes, these must be demonstrated to be efficient.

Further, with regard to SACOSS' statements that the AER should support DLC, the AER notes neither the NER nor the DMIS enforces the uptake of demand management projects or the uptake of a particular type of project over another. It is a DNSP's role to develop and select an efficient demand management project and the AER's role is to assess the project, either as part of the DMIS or via the capex and opex assessments.

The AER also notes SACOSS and the TEC's comments regarding a formal review of ETSA Utilities' demand management trials over the current regulatory control period, with a view to not losing the knowledge gained thus far. The AER understands that ESCOSA is intending to undertake a public review of the outcomes of the demand management programs funded in the current regulatory control period under its

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809 AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, pp. 86–87.

810 AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. viii.

demand management fund.[811] Further, while noting suggestions that the DMIA's capped amount is low, particularly compared to ESCOSA's demand management allowance in the current regulatory control period, the AER is aware that at the time of this decision, ETSA Utilities had not utilised all of its demand management allowance.

Finally, the AER notes the demand management expenditures quoted by UnitingCare do not present a complete overview of demand management expenditures. The quoted figures only appear to relate to expenditures funded under the Part A – DMIA. These figures do not account for the amount of foregone revenue for which ETSA Utilities will be eligible. Moreover, and of greater significance, this amount does not account for the demand management projects included in the opex and capex allowances for ETSA Utilities. ETSA Utilities proposed $22.6 million for demand management projects which has been included in the capex and opex allowances approved by the AER.[812]

14.4.2 Part B – Foregone revenue

The AER notes ETSA Utilities reiterated its proposal that the Part B – forgone revenue component be expanded to apply to any demand management project, citing a number of apparent disincentives to the uptake of demand management in the broader regulatory framework. While not advanced by ETSA Utilities in its regulatory proposal, these matters have been previously considered by the AER, principally in the framework and approach and the decision on the DMIS for Qld and SA DNSPs.[813] Nevertheless, the AER has reconsidered these arguments in the context of ETSA Utilities' regulatory proposal. These largely concern three sets of issues:

- possible interactions between demand management and incentive schemes
- the effect of ETSA Utilities' control mechanism on demand management
- interpretation of the operation of Part – B in relation to Part – A.

Interactions between demand management and incentive schemes

The AER reiterates its position that the regulatory framework provides ETSA Utilities with various options for compensation for its demand management efforts. The primary sources for recovery of demand management expenditures are through the capex and opex allowances approved by the AER as part of its distribution determination, in accordance with clauses 6.5.6 and 6.5.7 of the NER. These allowances compensate ETSA Utilities for expenditure that satisfies the opex and capex criteria at the time of the regulatory determination. The AER does not agree with ETSA Utilities that this position fails to recognise a number of factors and therefore justifies an expansion of the foregone revenue component.

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811 ESCOSA, *ETSA Utilities 2005–10 Electricity Distribution Price Determination, Part A – Statement of reasons*, April 2005, p. 59.

812 The figure comprises of $19 million in capex and $3.6 million in opex.

813 AER, *Final decision, Framework and approach paper, ETSA Utilities 2010–15,* November 2008; AER, *Demand management incentive scheme – Energex, Ergon Energy and ETSA Utilities 2010–15,* October 2008.

The AER agrees that while demand management aims to lower augmentation capex,[814] in many instances demand management projects will require additional opex to be incurred, which would ordinarily result in a penalty under the Efficiency Benefit Sharing Scheme (EBSS) for ETSA Utilities.[815] However, to minimise the impact on incentives to undertake efficient demand management programs, the EBSS explicitly excludes all costs associated with non–network alternatives (that is, demand management), including opex spent on demand management and expenditure under the DMIS, from the calculation of opex overspends and underspends.[816] This feature of the EBSS was also supported by the AEMC in its recent review of demand–side participation in the NEM.[817]

ETSA Utilities' proposition that the rate of return on the capex allowance is in some way inappropriate for demand management projects due to these projects apparently involving higher risks of failure, is misconceived. As already noted, demand management will often involve increases in opex while it aims to defer or remove the need for capex. However, irrespective of this point, demand management projects funded by the capex and opex allowances approved in the regulatory determination according to the capex and opex criteria would necessarily have been chosen by a DNSP because these would have been found to be more economically efficient, given the prevailing rate of return, than implementing network augmentation projects. If these projects are found to be economically efficient, there is no reason why they would not be implemented. The AER notes that the regulatory framework operates such that capex directed toward demand management will receive the same rate of return, whatever the impact of this expenditure on future network investment. In this context, an increased form of compensation for demand management projects could result in an inefficient level of capex and/or opex.

The AER notes that this process of evaluating the relevant costs and reliability aspects of a project against possible benefits underpins the pursuit of the most efficient option. Discretionary service standards, such as those underpinning STPIS targets actually provide impetus for such evaluation, through the possibility of financial penalties if projects fail to perform to certain reliability standards. The relative risks of financial penalties under the STPIS must be weighed against the benefits of selecting demand management over network augmentation by any prudent DNSP. This means demand management should not be carried out at the expense of a decline in service standards unless the benefits of the demand management outweigh the costs and risks. The AER's STPIS is designed to be as neutral as possible regarding the level of reliability provided by network solutions vis à vis non network solutions. As such, the STPIS does not distinguish performance on the basis of the option implemented by a DNSP. The AER therefore considers it reasonable to apply the STPIS without excluding demand management projects that fail to perform as expected.

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814 Augmentation refers to measures funded through capex allowances and aimed at extending or relacing the distribution network. This contrasts to non–network options (that is, demand management), which aim to lower demand and therefore reduce or delay the need for network augmentations.

815 AER, *Final decision, Framework and approach paper, ETSA Utilities*, November 2008, pp. 97–98.

816 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 378.

817 AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. viii.

This position is supported by the AEMC's review of demand–side participation in the NEM, particularly its assessment of the incentives and possible disincentives to demand–side participation arising from the regulatory framework. The AEMC considered that because service incentive schemes allowed DNSPs to appropriately compare levels of reliability and continuity of supply with likely penalties or benefits arising from network and demand management options, that they do not present impediments to efficient demand management.[818] The AEMC noted that if this was not the case there may be an inefficient bias towards demand management or network augmentation.[819]

The AEMC noted this does not mean that demand management would be dismissed in principle if considered less reliable. For example, if the cost of the demand management option was sufficiently low, and the risk of it impacting on the quality of supply could also be managed at relatively low cost, a prudent DNSP would prefer the demand management option.[820] The AEMC concluded that the STPIS does not present a barrier to efficient inclusion of demand management.[821] That is, the STPIS will only present a barrier to demand management should that option be inefficient. The AER therefore does not consider the STPIS presents a barrier to efficient demand management.

Finally, the AER does not find sufficient merit in the suggestion that a DNSP does not have access to benefits accruing to other industry sectors, such as transmission, generation or retailing. As already noted, ETSA Utilities can fund its demand management projects via the capex and opex allowances approved in the regulatory determination. Alternatively, if it successfully implements a project during the regulatory control period that did not form part of its capex and opex allowances, it will receive indirect compensation as this is likely to have lead to lower network investment. That is, ETSA Utilities' incurred costs may be less than anticipated due to the decline in peak or locational demand achieved by the demand management initiative, but the approved capex and opex allowance is based on a higher level of demand and remains unchanged. Alternatively, and in addition, the DMIS provides ETSA Utilities with other compensation options should it seek to undertake new trials and pursue more innovative solutions.

To the extent that the concern relates to the potential for the electricity supply chain structure to permit the benefits of demand management projects implemented by a DNSP to flow onto retail and generation sectors despite the costs being incurred by the DNSP, the AER notes it has previously addressed the matter.[822] However, the AER notes that similarly, ETSA Utilities stands to benefit from the demand management efforts of other segments of the electricity supply chain. As noted in the AEMC's review of demand–side participation, demand management is actively being pursued by retailers and TNSPs in addition to DNSPs.[823] The AER does not consider that there is sufficient evidence to suggest that such structural issues necessarily

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818 AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. 33.
819 AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. 32.
820 AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. 33.
821 AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. 29.
822 AER, *Explanatory statement and proposed DMIS to apply to Energex, Ergon Energy and ETSA Utilities – 2010–15*, June 2008, p. 20.
823 AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. 5.

represent a significant disincentive so as to require an increase in a DNSP's foregone revenue.

Effect of control mechanism on demand management

ETSA Utilities' contention that its WAPC control mechanism acts as a disincentive to demand management has been previously considered by the AER. The framework and approach set out the AER's intention to apply the Part B – foregone revenue component to ETSA Utilities on the basis that it would be under a WAPC.[824] The AER considered that justification for this approach was based on its acknowledgment that there is some concern about the possibility of a WAPC representing a disincentive to demand management, whether real or perceived.[825] Given the uncertainties regarding the need for foregone revenue compensation, the AER decided to follow a cautious approach to foregone revenues by applying an additional incentive through the DMIS that is purposely modest in nature.

More recently, the AEMC's review of demand–side participation in the NEM has further explored the matter of possible disincentives toward demand management in the regulatory framework and has rejected the need for a foregone revenue compensation mechanism to overcome a bias against efficient demand management within the regulatory framework. According to the AEMC, while DNSPs under a WAPC do face some loss of sales revenue should a demand management project prove successful, this cost is actually required to ensure that DNSPs only pursue the correct amount of demand management, prioritising where efficiency savings are greatest. Further, if demand management is the more efficient option for the DNSP, it will actually earn systematically higher profits by using demand management rather than augmenting the network.

The AER notes that both the TEC and UnitingCare have suggested that demand management is the most cost effective approach and further that the AER should consider setting benchmarks for demand management expenditure. The AER agrees with the TEC to the extent that it is the AER's responsibility to ensure that DNSPs are regulated for efficiency. However the AER notes that while in some cases demand management might prove efficient, it does not follow that it is always the most efficient option, a point also acknowledged as part of the AEMC's review, particularly in regard to similar submissions from the TEC and other stakeholders.[826] There are many factors that a DNSP considers in evaluating network versus demand management options, some of which may be location specific. The AER considers that it is reasonable to suggest that in some cases carrying out demand management might be inefficient and therefore it is prudent for a DNSP to be responsible for determining which option is more efficient.

In any case the AER notes that the NER do not confer on the AER an interventionist role with regard to demand management. If a DNSP selects a demand management project under the DMIS, or as part of the opex and capex proposals as ETSA Utilities has done, then the AER's role is to assess the projects submitted. Further, in assessing a DNSP's forecast opex and capex in accordance with the criteria set out in clauses

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[824] AER, *Final framework and approach – ETSA Utilities*, November 2008, p. 99.
[825] AER, *Final framework and approach – ETSA Utilities*, November 2008, p. 99.
[826] AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. 21.

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. 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.

While noting the AEMC's views on the need for a forgone revenue component, the AER has taken a cautious approach to this issue given that these programs are in their infancy and much of the debate on this issue has been highly theoretical to date. As the results of these programs and their interaction with the regulatory framework become clearer, the need and desirability of the foregone revenue component will be re–evaluated.

However, the AER also considers there may be other reasons for why such an incentive scheme might be justified. If there is a perceived bias against demand management in established cultures of a business and their management practices, as was noted by stakeholders during preparation of the AER's decision paper on the DMIS for Qld and SA DNSPs, then an incentive may be justified as a stimulus to change.[827] This point was also supported by the AEMC's review. The AER notes the DMIS is broadly consistent with this purpose in that it focuses on providing an impetus for innovation and the building of capacity and capability with a view to allowing greater consideration of demand management in future. The AER's DMIS complements the broader regulatory framework, by providing some compensation for more innovative or untested demand management efforts, rather than explicitly offsetting a particular bias against demand management in the regulatory framework.

The AER considers its decision to apply a DMIS to ETSA Utilities that is modest in nature, and does not provide foregone revenue compensation for all demand management projects (only those implemented under the Part A – DMIA) is consistent with the above views. In light of the AEMC's review and the uncertainties that still remain concerning demand management, the AER does not consider that significantly expanding the operation of the Part B – foregone revenue component is justified.

Application of Part B – Foregone revenue component

The AER also notes ETSA Utilities' request for clarity and its proposal that at a minimum, the DMIS should be varied to provide that when the Part A – DMIA cap has been met, demand management projects can still be approved under Part A of the DMIS for the purpose of recovering foregone revenues in Part B. The AER considers this proposal is effectively a reworking of ETSA Utilities' earlier proposal such that all demand management projects would be eligible for foregone revenue compensation.

The AER confirms such an interpretation was not intended. The AER will not be approving projects under the Part A – DMIA if its cap has been met, for the purpose

[827] AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. 18; and AER, *Explanatory statement and proposed DMIS to apply to Energex, Ergon Energy and ETSA Utilities – 2010–15*, June 2008, p. 7.

of providing foregone revenues. The AER does not consider this position acts as a disincentive to the uptake of efficient demand management projects.

Overall comments

The AER has assessed the arguments presented by ETSA Utilities in its revised regulatory proposal and maintains its position that redesigning the DMIS by broadening its power is not justified. The AER does not consider the regulatory framework is biased against the pursuit of efficient demand management. However, the AER acknowledges the need for a modest incentive for innovative, untested demand management, which the DMIS provides. In particular the AER considers:

- the regulatory framework provides ETSA Utilities with varied options for compensation of its demand management efforts
- the EBSS does not negatively interact with demand management, whether undertaken through the DMIS, the regulatory determination, or during the regulatory control period
- the STPIS does not present a barrier to efficient demand management
- the WAPC control mechanism applying to ETSA Utilities need not represent a barrier to efficient demand management, however, an additional incentive to account for foregone revenue acts as a modest mechanism to address any perceived uncertainty and legacy issues that may otherwise lead to inefficient outcomes.

The AER has been monitoring a number of reviews that could impact on its approach to demand management. The review of energy market frameworks in light of climate change policies, and the second stage of the AEMC's review of demand–side participation in the NEM have now been published.[828] Recommendations have been made by the AEMC, particularly as to any future design of a national DMIS and the incentives for efficient connection of embedded generation, but these are yet to be considered by the MCE. The AER will monitor the MCE's final decision, and also the development of the third stage to the AEMC's review,[829] before developing a revised or national DMIS.

14.5 AER conclusion

The AER confirms its position, as set out in its framework and approach, to apply the DMIS to ETSA Utilities. The DMIS will comprise of a Part A – DMIA component and a Part B – foregone revenue component. Part A will be capped at $3 million in the next regulatory control period. The capped amount will be allocated to ETSA Utilities as an ex–ante allowance, in five equal instalments of $600 000. The ex–post review and operation of the DMIA will be as set out in the DMIS.

Part B will be uncapped but subject to the restrictions set out in the DMIS. Part B will be applied consistent with the methodology set out in the DMIS.

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[828] Further information on the AEMC's reviews are accessible on its website: <http://www.aemc.gov.au>.
[829] AEMC, *Final report, Review of demand–side participation in the NEM*, December 2009, p. vi.

14.6 AER decision

In accordance with clause 6.12.1(9) of the NER, the DMIS to apply to ETSA Utilities is the DMIS set out in AER, *Demand management incentive scheme – Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008.

The Part A – DMIA and the Part B – foregone revenue components of the DMIS will apply to ETSA Utilities. The DMIA will be capped at $3 million for the next regulatory control period and allocated to ETSA Utilities in equal annual instalments of $600 000 for each year of the next regulatory control period.

In accordance with clause 6.3.2(a)(3) of the NER, the application of the DMIS to apply to ETSA Utilities is as specified in section 14.5 of this decision.

15 Pass through arrangements

This chapter sets out the AER's assessment of ETSA Utilities' 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 'fixed' price path over the regulatory control period based on the forecast cost of providing standard control services. The DNSP is therefore incentivised 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 a DNSP can be exposed to risks beyond its control, 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 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 if certain events occur. This pass through of costs is achieved through an amendment to the price or revenue determination.

15.1 AER draft decision

The AER accepted the following pass through events as nominated pass through events for ETSA Utilities:[830]

- smart meter event
- carbon pollution reduction scheme event
- feed–in tariff event
- native title event
- a general nominated pass through event.

The AER considered the other events proposed by ETSA Utilities did not meet the AER's assessment criteria and therefore those events were not accepted as nominated pass through events. The AER considered the proposed events either fell outside the scope of the draft decision or would otherwise come within the definition of a general nominated pass through event.[831]

For general nominated events the AER stated it will apply a materiality threshold of one 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 stated it will apply a materiality threshold of the administrative costs of assessing an application relating to specific nominated events.[832]

15.2 Revised regulatory proposal

ETSA Utilities accepted some aspects of the draft decision but did not accept the assessment criteria for specific pass through events identified by the AER in the draft decision. In addition, ETSA Utilities did not accept the materiality threshold for general pass through events proposed by the AER in the draft decision.[833]

ETSA Utilities did not accept the draft decision in relation to the following specific nominated pass through events:[834]

- industry standards event – ETSA Utilities considered the AER had no legal basis to reject this nominated pass through event
- retailer failure event – ETSA Utilities did not consider the AER had accepted the high level of risk of retailer failure and noted that the Essential Services Commission of Victoria had included a pass through for this event in the current regulatory control period

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830 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 407–408.
831 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 405–407.
832 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 400–401.
833 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
834 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.

- interim period event – ETSA Utilities considered that the AER has the legal capacity to make a decision to include this event.

ETSA Utilities also proposed the following specific nominated pass through events:[835]

- industry standards change event
- interim period event
- retailer failure event
- retailer of last resort (ROLR) obligation event
- Kangaroo Island cable failure event.

ETSA Utilities proposed a revised interpretation for the definition of a carbon pollution reduction scheme event.[836]

15.2.1 Assessment of nominated pass through events

ETSA Utilities considered that the AER had not sufficiently explained its reasons for amending its criteria for assessing proposed pass through events such that a specific nominated pass through event must be 'highly likely' rather than 'foreseeable'. In addition, ETSA Utilities submitted that an assessment of the validity of a pass through event on the basis that it is highly likely to occur is an inconsistent application of the specific pass through provisions in the NER and is unreasonable. ETSA Utilities mounted a similar argument in relation to the threshold criteria of 'unexpected' for the general nominated event.[837]

ETSA Utilities stated the position of the Ministerial Council on Energy and its standing committee of officials (MCE SCO) is that any event for which costs are uncertain and outside the control of the DNSP can be nominated as a pass through event.[838] ETSA Utilities further submitted the NER permits a DNSP to specify any event as a pass through event and that it is for the AER to then determine, consistent with the relevant provisions in the NER and the NEL, including sections 7 and 7A of the NEL, whether the event should be nominated in the distribution determination as a pass through event.[839]

ETSA Utilities also submitted the AER's decision in respect of additional pass through events should be guided by the pass through events that are specifically provided for in chapter 10 of the NER, for example, the terrorism event.[840]

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835 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
836 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
837 ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 141–142.
838 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 142.
839 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 142.
840 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 142.

It was further argued by ETSA Utilities that the AER should only amend its regulatory proposal (which sets out, among other matters, proposed pass through events) to the extent necessary to enable it to be approved in accordance with the NER.[841]

15.2.2 Materiality threshold

ETSA Utilities maintained that materiality of expenditure incurred as a result of an event should not be determined by a one per cent 'bright line' threshold. To identify what level of expenditure should be considered material, ETSA Utilities stated that:[842]

- clause 14, guideline 12 of ETSA Utilities' distribution license indicates that projects with a capital cost of greater than $2 million may be considered significant

- the AEMC, in its final report, *Review of National Framework for Electricity Distribution Network Planning and Expansion*, recommended the Regulatory Investment Test for Distribution be applied for any project where the capital costs exceed $5 million and therefore qualified as 'significant investments'.

ETSA Utilities stated that a one per cent threshold is 'far too onerous' and proposed that if the AER is to maintain a 'bright line' approach to the materiality threshold, the threshold should be $5 million of capex and/or opex.[843]

15.2.3 Proposed specific nominated pass through events

In addition to the specific nominated pass through events accepted by the AER and listed in section 15.1, ETSA Utilities proposed an additional five events be nominated as pass through events.[844]

Industry standards change event

The industry standards change event was proposed by ETSA Utilities in its regulatory proposal and rejected by the AER in its draft determination. While ETSA Utilities disputed the validity of assessing whether an event is 'highly likely', ETSA Utilities considered there is a high probability an industry standards change event will occur in the next period. ETSA Utilities considered indications emerging from the Bushfires Royal Commission suggested a high probability of a significant industries standards change event occurring within the next regulatory control period. ETSA Utilities proposed the following definition for an industry standards change event:[845]

> an industry standards change event occurs if:
>
> a) as the result of a decision of a court, standards authority, Government or Government authority , a prudent operator, acting reasonably, would undertake particular action; and

[841] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 143.
[842] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
[843] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 144.
[844] ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 145–152.
[845] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.

> b) in undertaking that action, ETSA Utilities incurs material costs which it will not otherwise recover through an increase in distribution revenue.

Interim period event

The interim period event was proposed by ETSA Utilities in its regulatory proposal and rejected by the AER in its draft determination. ETSA Utilities maintained its position from its regulatory proposal. Further, ETSA Utilities submitted that clause 6.12.1(14) of the NER does not restrict the ability to nominate events in a distribution determination solely to events that occur during the regulatory control period under consideration. ETSA Utilities proposed the following definition for an interim period event:[846]

> an interim period event is an event that:
>
> a) occurs before the commencement of the relevant regulatory control period; and
>
> b) would be a pass through event if it occurred in the regulatory control period; and
>
> c) has a costs impact in the relevant regulatory control period which has not been included in ETSA Utilities' operating and capital expenditure forecasts.

Retailer failure event

The retailer failure event was proposed by ETSA Utilities in its regulatory proposal and rejected by the AER in its draft determination. ETSA Utilities maintained its position in its regulatory proposal. While ETSA Utilities disputed the validity of assessing whether an event is 'highly likely', ETSA Utilities considers there is a high probability a retailer failure event will occur in the next period. ETSA Utilities considered that full contestability and the number of retailers in the South Australian retail market implied a high level of retailer failure risk. ETSA Utilities also noted that the Victorian Essential Services Commission recognised the possibility for a retailer failure event in its final decision for the 2006–2010 regulatory control period.[847]

While ETSA Utilities noted it takes steps to protect itself against retailer failure, it stated that such provisions are not necessarily sufficient for the following reasons:[848]

- time delays in securing Co-ordination Agreements from retailers expose ETSA Utilities to risk as a result of retailers who refuse to provide the requisite credit support
- the credit support arrangements in the statutory Co-ordination Agreements expose ETSA Utilities to the risk of being unable to recover the differences between the undertaking made by a given retailer and that retailer's actual ability at a given time

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[846] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
[847] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
[848] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.

- it is unlikely that a change in the regulatory structure surrounding credit support arrangements in South Australia would be considered a regulatory change event pass through under the rules.

ETSA Utilities proposed the following definition for a retailer failure event:[849]

> a retailer failure event occurs if:
>
> a) a retailer is placed in administration, liquidation or their license is revoked; and
>
> b) as a consequence, ETSA Utilities does not receive revenue to which it was otherwise entitled.

Retailer of last resort obligation event

The ROLR obligation event was not included in ETSA Utilities' regulatory proposal. ETSA proposed the ROLR obligation event as a result of the AER's rejection of the proposed nominated pass through extraordinary event. ETSA Utilities noted the amendments to the *Electricity Act* 1996 (SA) result in ETSA Utilities being subject to the costs associated with its role of ROLR until the end of the next regulatory control period. ETSA Utilities submitted it should be able to recover the efficient cost of compliance with this regulatory obligation. ETSA Utilities proposed the following definition for a retailer of last resort obligation event:[850]

> a retailer of last resort obligation event occurs if:
>
> a) ETSA Utilities is called upon to act as a retailer of last resort under section 23 of the Electricity Act 1996 (SA); and
>
> b) as a consequence, ETSA Utilities incurs costs which it will not otherwise recover.
>
> For the avoidance of doubt, this includes payments made to a retailer (s) where ETSA Utilities has contracted its ROLR obligations to that retailer.

Kangaroo Island cable failure event

The Kangaroo Island cable failure event was not included in ETSA Utilities' regulatory proposal. In its regulatory proposal, ETSA Utilities proposed capex of $95 million for the improvement of Kangaroo Island's network security.[851]

ETSA Utilities noted the AER considered the Kangaroo Island project should be removed from ETSA Utilities' forecast capex. ETSA Utilities therefore removed the Kangaroo Island project and proposed it should have some means to recover the costs of maintaining supply and costs associated with repair or replacement if supply to the island is disrupted during the next regulatory control period. ETSA Utilities submitted the need to undertake any significant capital and/or operational expenditure in relation to the supply of energy to Kangaroo Island should be treated as analogous to a

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849 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
850 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
851 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.

contingent project under the transmission rules. ETSA Utilities proposed the following definition for a Kangaroo Island cable failure event:[852]

> a Kangaroo Island cable failure event occurs if, during the regulatory period 2010–2015:
>
> a) the undersea cable to Kangaroo island fails; and
>
> b) ETSA Utilities incurs higher operating expenditure and capital expenditure costs in the maintenance of supply to Kangaroo Island, including but not limited to the repair or replacement of the undersea cable and the cost of securing electricity generated on the island.

15.2.4 Carbon pollution reduction scheme event

ETSA Utilities stated it accepted the decision of the AER to nominate a CPRS event as a specific nominated pass through event. It considered the definition proposed by the AER can be construed as covering all obligations imposed on ETSA Utilities arising from the imposition of a price on carbon dioxide (and its carbon equivalent in relation to other greenhouse gases), whether as a result of a trading scheme or some other mechanism.[853]

15.3 Submissions

15.3.1 United Energy Distribution

United Energy Distribution (United Energy) expressed concern that the AER 'appears to believe that the cost pass through provisions provide better incentives to control costs than self insurance'.[854] United Energy stated a pass through arrangement has poor incentive properties as customers, rather than the network service provider, face the costs associated with a particular event.

United Energy also noted the AER position on self insurance and cost pass through will mean that network service providers will be exposed to losses to the extent the losses fall below the cost pass through materiality threshold.

15.3.2 Energy Consumers Coalition of South Australia

The Energy Consumers Coalition of South Australia (ECCSA) was concerned the AER has established a general pass through event. ECCSA considered a general pass through event would reimburse ETSA Utilities at the expense of consumers for uncontrollable and unexpected events which cannot be prevented or managed by prudent risk management.

ECCSA proposed pass through events should be made specific in a reset decision and additional events should not be allowed to be added during the regulatory control period.

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[852] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
[853] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 139.
[854] United Energy, *Submission to the AER's draft decision for ETSA Utilities 2010–2015*, February 2010, p. 1.

15.3.3 SP AusNet

SP AusNet suggested 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.[855] In particular, SP AusNet suggested the one per cent of revenue threshold applied by the AER was inconsistent with the NEL in that a business should be provided a reasonable opportunity to recover efficient costs. SP AusNet suggested for an event that fell just below the threshold of one per cent, its profits would reduce by five per cent in that year and this would be inconsistent with the requirements of the NEL.[856]

SP AusNet considered the weak incentive properties of cost pass through, which it considered to be demonstrated by the AER's adoption of a 1 per cent of revenue materiality threshold to limit claims, were a reason to prefer self insurance over cost pass through mechanisms.[857]

15.3.4 Energy Users Association of Australia

The Energy Users Association of Australia (EUAA) stated it does not support cost pass through as a matter of principle. The EUAA stated pass through provisions will always be asymmetric in favour of the network businesses and urged the AER to consider the option of a rule change that will lead to 'more balanced outcomes in future'.[858]

As well as expressing general concerns relating to cost pass through, the EUAA identified the following specific nominated pass through events accepted by the AER as areas of particular concern:[859]

- **CPRS event –** the EUAA considered that accepting a CPRS specific nominated pass through event will eliminate any incentive for DNSPs to reduce the costs associated with such a scheme

- **Feed–in tariff event –** the EUAA noted that ETSA Utilities forecast opex for feed–in tariffs. Further, the EUAA considered feed–in tariffs to be business as usual over the next regulatory control period and into the future. The EUAA note that the AER has determined that a pass through cannot be accepted if there is provision for these costs to be factored into opex or capex. As such, the EUAA request that the AER clarify how this relates to the feed–in tariff pass through

- **Native title pass through event –** the EUAA stated that it does not support native title pass through for new distribution projects. The EUAA considered that ETSA Utilities should be exposed to incentives to reduce costs related to native title claims for new distribution projects.

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855 SP AusNet, *Submission to the AER's draft distribution determination for South Australia,* 16 February 2010, p. 4.

856 SP AusNet, *Submission to the AER for South Australia*, 16 February 2010, p. 4.

857 SP AusNet, *Submission to the AER for South Australia*, 16 February 2010, p. 4.

858 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, p. 31.

859 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, pp. 31–32.

15.4 Issues and AER considerations

15.4.1 Criteria for assessing pass through events

The AER disagrees with ETSA Utilities in respect of the AER's discretion for determining the pass through events that are to apply in a distribution determination.

The AER considers the approach it adopted in the draft decision is in accordance with the pass through provisions in the NER and the broader requirements in the NEL. This section outlines the AER's reasoning. As a preliminary matter, the AER has briefly set out the legal framework that applies to pass through events and its interpretation of this framework.

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, contrary to ETSA Utilities' assertion that the AER should be guided by the events listed in chapter 10, 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.

It is noted that ETSA Utilities considers that the AER should amend its regulatory proposal only to the extent necessary to enable it to be approved in accordance with the NER. These words appear to be drawn from clause 6.12.3(f) of the NER. While clause 6.12.3(f) generally limits the AER's discretion in clause 6.12.1(14), the 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.

To the extent that the NER permits a DNSP to propose an event as a pass through event and the AER to approve such event provided it is consistent with the NER, the AER reiterates there is little guidance provided in the NER as to the types of matters that should qualify as additional pass through events. While ETSA Utilities considers that any event for which costs are uncertain and outside of the control of a DNSP should be the principal considerations (and has referred to MCE SCO material in this regard), neither the NER, nor the NEL, explicitly provide for these requirements. While the AER has had regard to these matters this does not mean that the AER cannot also attach weight to other matters in devising the criteria for pass through events. The approach suggested by ETSA Utilities also seems inconsistent with the above mentioned provisions in the NER which confer upon the AER a broad discretion in determining additional pass through events in what is a highly prescriptive regulatory regime. In the absence of criteria that specify the matters that the AER should take into account, the AER has considered it appropriate to develop assessment criteria. This promotes regulatory certainty and the AER considers the assessment criteria achieve the national electricity objective and revenue and pricing principles in sections 7 and 7A of the NEL, respectively. For these reasons, the AER does not share ETSA Utilities' view that the criteria it has devised are inconsistent with the NER or are unreasonable.

The AER agrees with ETSA Utilities that the exercise of its discretion is 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 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 beyond the control of the DNSP.

The AER also considers 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 considers the pass through events included in the draft decision are flexible, pragmatic and consistent with the requirements of the NER. The AER has, in addition to the pass through events defined in the NER, accepted a general nominated pass through event. As such it is not necessary for DNSPs to submit tightly defined and singularly focussed nominated pass through events, as suggested by ECCSA in its submission. A general nominated pass through event is consistent with the broad definition of pass through event in chapter 10 of the NER.[860] Furthermore, the AER considers any event that impacts on a DNSP and materially increases its costs could potentially be considered for cost pass through under the general nominated pass through event, subject to the requirements of the NER.[861] Consequently, the AER does not agree with ETSA Utilities that its approach to cost pass through limits the scope of a DNSP to seek pass through of costs that are uncertain or outside the control of a DNSP.

The AER has also accepted a number of specific nominated pass through events. These events are different to general nominated pass through events in that the AER considers that for these particular events a different materially threshold should apply (discussed further below). Consequently, the test that the AER applies to these events (highly likely) is to determine the appropriate threshold to be applied and is not a test (as suggested by ETSA Utilities[862]) to determine whether costs associated with events can or cannot be sought via cost pass through. The AER revised the term 'foreseeable' to 'highly likely' following the review conducted by the Australian Competition Tribunal in respect of the AER's NSW electricity distribution determination in 2009. The AER considered that it was necessary to address the concerns of some DNSPs that the concept of 'reasonable foreseeability' might import either a 'possibility' or 'probability' based test. The AER has always considered that the test was probability-based and considers that the use of the words 'highly likely' in the assessment criteria removes doubt for stakeholders. The AER therefore disagrees with ETSA Utilities that it has meaningfully amended the criteria or that the criteria has further restricted the nomination of a cost pass through on the basis of its likelihood.[863]

The AER considers that the general nominated pass through event provides a broad scope for the recovery of costs that were not included at the time of the regulatory determination. Nevertheless, the AER considers that the inclusion of specific nominated pass through events has additional benefits for both DNSPs and customers. In normal circumstances, the AER would expect that any anticipated capital or operating expenditures would be included in a DNSP's regulatory proposal on the basis of forecasts. However, the AER accepts that in some very limited circumstances, it may be appropriate to avoid the potentially significant forecast

860 Pass through event is relevantly defined in chapter 10 of the NER as '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).'

861 For example, the clauses under 6.6.1 of the NER.

862 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 141.

863 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 141.

errors in relation to some events that are anticipated during the regulatory control period. Such circumstances arise for events that are subject to significant uncertainty and, therefore, potential forecast error, where the consequence of including these costs in the capex or opex forecast would be to the disadvantage of customers if, for example, the event was never to materialise. Similarly, DNSPs would be disadvantaged if the actual costs were higher than those forecast. In these circumstances, the AER considers that a pass through of costs with only a notional materiality threshold is in the interest of customers (that is, a specific nominated pass through event).

For these reasons, the AER has adopted an approach to pass through that distinguishes between pass through events on the basis of their likelihood with respect to the materiality threshold to be applied to the eligible pass through amount. However, the AER accepts that it would be consistent with the NER to have adopted a simpler pass through mechanism that applied a uniform materiality threshold of one per cent of annual revenue to all nominated pass through events. The AER has not taken this approach because it considers there are benefits from a more flexible approach, as noted above. The AER may consider implementing a simpler approach in the future.

In summary, the AER is satisfied that a general nominated pass through event satisfactorily provides a mechanism for the recovery of costs not anticipated at the time of the determination which would have a material impact on the ability of a DNSP to provide distribution services without undermining the incentives inherent in the regulatory regime. That said, the AER will keep the issue of how these general nominated events should be expressed under review to consider whether they can be clarified further in future regulatory determinations. The AER is also satisfied that in special circumstances the inclusion of specific nominated events is appropriate to reduce the potentially adverse effects of highly likely events that are subject to significant uncertainty in regard to timing and/or cost.

15.4.2 Materiality threshold

The AER notes ETSA Utilities' view that there should not be a 'bright line' materiality threshold and that the AER should instead adopt the approach of the previous regulator, ESCOSA. ESCOSA had made a subjective assessment of materiality based on the merits of each individual case.[864] However, the AER considers that there are benefits in providing a clear indication of an amount that it considers to be material. In particular, this will reduce the likelihood of DNSPs incurring costs, unnecessarily, of preparing applications for cost pass through that are not accepted on the basis the costs are not material. Contrary to ETSA Utilities' assertion that the materiality threshold is not supported by the NER or the NEL, the AER considers the materiality threshold is consistent with the national electricity objective in section 7 of the NEL. That is, by clearly indicating its position with respect to the threshold, the AER considers DNSPs will better understand the costs for which they are responsible rather than incorrectly assuming that certain costs would be able to be passed through to customers. The AER considers that this information can be used by DNSPs to manage unexpected events that impose costs on a DNSP that are below the materiality threshold. In doing so, the AER considers this

[864] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 143.

information will aid efficient investment in and operation of the networks, which is embodied in the national electricity objective and Pricing Principles as noted in section 15.4.1 of this decision.

The NER does not prescribe the means for determining the amount of the materiality threshold.[865] The AER notes, however, the following matters which support the adoption of a uniform 1 per cent of revenue materiality threshold. The figure has been accepted in different jurisdictions, including IPART and the QCA, and by some DNSPs including Ergon Energy [866]and Country Energy[867], amongst others. The AER considers that the 1 per cent of annual revenue threshold has operated successfully in those jurisdictions with this (or a similar) threshold. The AER is also unaware of any DNSP not having met its service obligations by reason of the operation of the threshold and the resultant inability to pass costs through to customers. The AER does not agree with SP AusNet that 1 per cent of revenue is too high and would undermine the ability of the DNSP to recover its efficient costs.

The AER notes ETSA Utilities argued, in the alternative, that if the AER is to maintain a bright line materiality threshold, that this should be a threshold of $5 million of capex and/or opex. ESTA Utilities submitted a 'threshold of $5 million of capital and/or operating expenditure is consistent with what is generally thought to be a material project or program'.[868] The AER considers that the impact of an unexpected event on the provision of standard control services is dependent on both the costs imposed and their size relative to the annual revenues of the DNSP. That is, a $5 million event would have different implications for a smaller DNSP, like ActewAGL, compared a larger DNSP, for example, Energex. Consequently, the AER considers that the threshold for determining the materiality of a pass through event should be described in terms of the revenue requirement of a DNSP and not a fixed amount.

With respect to costs that occur in more than one regulatory year, the AER considers that the materiality of a pass through should be considered in the context of the revenue stream available to DNSPs.[869] This includes the cost of an event in one year or over multiple years. Where an event imposes costs over multiple years a DNSP has a greater opportunity to manage those costs given the revenues available to it over the longer period. For this reason the AER considers that the cost pass through threshold should be applied in each year that costs are incurred. Therefore, if a pass through events occurs, the materiality of the cost of the event (opex costs, return of capital and depreciation) incurred each year will be considered against revenues of the relevant year. Costs of the event may exceed the materiality threshold in some years and not in others. Only in those years that the materiality threshold is exceeded will the AER consider the amounts eligible for pass through.

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[865] See also the matters set out in section 15.4.1 above.
[866] Ergon Energy, *Revised regulatory proposal*, January 2010, p. 203.
[867] AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 280.
[868] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 144.
[869] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 143.

15.4.3 Pass through events rejected by the AER

ETSA Utilities disagreed with the AER's treatment of the following pass through events that it had nominated for the next regulatory control period: the change in industry standards event, the retailer failure event and the interim period event. While the AER acknowledges that it did not accept the industry standards and retailer failure events as specific nominated events, the AER does not agree that they were rejected as nominated events. Instead, the AER considers these events, if they did occur, would be general nominated pass through events. In relation to the interim period event, the AER remains of the view that this event is outside of its jurisdiction.

15.4.3.1 Retailer failure

The AER does not accept that a retailer failure event is highly likely to occur over the next regulatory control period, although it is possible. The AER acknowledges 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 ETSA Utilities.[870] The AER understands that the failure of Jackgreen is only the second occasion on which a retailer default has occurred under the NEL.

Notwithstanding the occurrence of the Jackgreen event, the AER continues to hold the view that a significant retailer failure is an unlikely event. 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 to occur. Consequently, the AER does not consider that retailer failure should be included as a specific nominated cost pass through event.

In the event of a significant retailer failure, ETSA Utilities 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.

15.4.3.2 Change in industry standards

The AER considers that a change in industry standards event is a general description of any event that might result in changes to ETSA Utilities' operational requirements, including: regulatory obligations, licence conditions or compliance requirements. The event is therefore not clearly identified as a specific event. In addition, a change in industry standards may already be captured by the pass through events defined in the NER, for example, a regulatory change event, although it is difficult to be certain because the potential range of events that may be captured under ETSA Utilities' proposal is very wide.

While ETSA Utilities cites matters canvassed in the proceedings currently being conducted before the Bushfires Royal Commission in Victoria to support the inclusion of a change in industry standards event, the Bushfires Royal Commission has yet to make any recommendations in this regard. The likelihood of a change in industry standards event, on this particular basis, is, at best, speculative.

[870] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 147.

For these reasons, the AER considers that a change in industry standards event does not qualify as a specific nominated pass through event. As noted earlier, however, the occurrence of such an event may qualify for pass through under the general nominated pass through event or, possibly, under an event defined in the NER.

15.4.3.3 Interim period event

The AER notes ETSA Utilities' view that the AER is not restricted in its ability to include only those pass through events that occur within the regulatory control period under question. The AER has reconsidered this matter and agrees with ETSA Utilities that the NER enables it to nominate an event that takes place before the next regulatory control period.

However, the AER does not consider that an interim period event, as defined by ETSA Utilities, meets the requirements of the specific nominated pass through event. The event is not clearly defined nor could the events that might be associated with an interim period event be individually regarded as highly likely.

15.4.4 New pass through events

15.4.4.1 Retailer of last resort obligation event

The AER notes that ETSA Utilities' responsibilities as a ROLR are unique in Australia. This is because in most other jurisdictions the ROLR is an electricity retailer. The AER has concerns that costs associated with retail activities could be recovered through distribution use of service charges.

However, in view of ETSA Utilities' unique role as a ROLR in South Australia, the AER accepts that costs associated with this event constitute a specific nominated pass through event. The AER accepts that should a ROLR event occur and ETSA Utilities is not provided with an opportunity to recover efficient costs, it could have a material impact on its ability to provide distribution services. This treatment effectively continues the existing jurisdictional practice.

The AER notes this regulatory obligation imposed on ETSA Utilities is currently being considered as part of proposed legislation contained in the National Energy Customer Framework (NECF). However, it is unclear when the relevant legislation will be introduced.

The AER notes that the event is clearly identified and is not otherwise captured in the pass through events defined in the NER.

15.4.4.2 Kangaroo Island cable failure event

The AER considered ETSA Utilities' proposal on expenditure for the undersea cable to Kangaroo Island in its draft decision. The AER considered that the proposed expenditure was not prudent and as a consequence did not accept the proposed expenditure met the requirements of the NER.[871]

[871] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 151.

In response to the draft decision, ETSA Utilities proposed a nominated pass through event for a failure of the undersea cable to Kangaroo Island. The AER does not consider this event qualifies as a specific nominated pass through event as its occurrence, while possible, is not highly likely.

The AER considers that a DNSP incurring costs that are simply unexpected or are a result of forecast error would not qualify for pass through as to do so would undermine the incentive framework on which this decision is based, as noted at the beginning of this chapter. Nevertheless, the general nominated event provides a mechanism whereby ETSA Utilities could seek to pass through costs associated with a Kangaroo Island cable failure. The AER will assess any application for cost pass through with reference to this decision and the requirements of the NER.

15.4.5 Revisited pass through events

15.4.5.1 CPRS

In the draft decision, the AER accepted CPRS as a specific nominated pass through event. In its revised proposal, ETSA Utilities has proposed that the definition of this event be revised.

The AER notes that there is a high level of uncertainty regarding the future implementation of a CPRS in terms of the scope of the scheme and the timing of the scheme being introduced. While this would suggest that the event no longer qualifies as a specific nominated pass through event (as accepted by the AER in its draft decision) the AER considers that it would be unreasonable to reconsider the matter at this time.

By definition, a specific nominated pass through event should be narrowly defined and only excluded from forecast expenditure on the basis of uncertainty in regard to the timing and extent of costs. ETSA Utilities’ proposal to broaden the definition of a CPRS event is a reflection that the event (as defined is in the draft decision) is no longer a certainty and that alternative policy proposals are possible.

In all likelihood, the introduction of a future emission trading scheme or carbon reduction scheme may constitute a regulatory change event that is already defined under the NER. On this basis, 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.

The AER acknowledges EUAA’s concerns regarding the CPRS pass through event. The NER requires that any costs associated with a CPRS event would need to meet the requirements of clauses 6.6.1 of the NER which specifies that, amongst other things, that costs are incremental, are not already accounted for in the annual revenue requirement and that all steps have been taken to minimise any pass through amounts. The AER considers that DNSP are aware of these requirements in the NER and that this will provide an incentive for DNSPs to minimise their CPRS compliance costs.

15.4.5.2 Feed–in tariff event

The AER notes that the EUAA does consider that any adjustment should be made to 'true up' the actual cost of the feed–in tariff payment from the amounts included in the opex forecast. The AER considers that feed–in tariffs are beyond the control of a DNSP and that the forecast is unreliable because of a lack of history regarding these payments in the past. Consequently the AER considers that it is in the interest of consumers to ensure that both DNSPs and consumers incur neither a benefit nor a penalty from the feed–in tariff scheme.

15.4.5.3 Native Title event

The AER notes the concerns of the EUAA that the pass through of Native Title costs would reduce the incentive of ETSA Utilities to reduce native title related costs in the future. The AER considers that the outcome of current court proceedings in regard to the native title cases, as referred to in its draft decision, could result in costs to ETSA Utilities that are beyond its control should be passed through to consumers once known. Consequently, the AER considers that the inclusion of this event would not diminish the incentive for ETSA Utilities to reduce costs related to native title because any pass through payment would be scrutinised against the requirements of the NER.

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 ETSA Utilities:

> A **smart meter event** is an event which results in an obligation being externally imposed on ETSA Utilities 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:
>
> - the definition of 'regulatory change event' in the NER (read as if paragraph (a) of the definition, was not part of the definition)
> - 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 ETSA Utilities arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth or South Australian government during the course of the next regulatory control period and which:
>
> (a) does not fall within any of the following:
>
> - the definition of 'regulatory change event' in the NER (read as if paragraph (a) of the definition, was not part of the definition)

- any other category of pass through event

(b) materially increases the cost of providing direct control services.

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 ETSA Utilities for that regulatory year is higher or lower than the amount of feed–in tariff payments (if any) that is provided for in ETSA Utilities' annual revenue requirement for that regulatory year.

For the purpose of this definition, a feed–in tariff payment is a payment to a customer in relation to electricity fed into the network by that customer (including pursuant to s36AD of the *Electricity Act 1996*). For the avoidance of doubt, a payment includes a credit against charges payable.

A **native title event** occurs if, as the result of any of the 10 native title matters in which ETSA Utilities is currently involved (identified in ETSA Utilities, *Regulatory proposal*, July 2009, attachment PT04 listing of native title claims, confidential), ETSA Utilities incurs material costs constituting:

- *any compensation or damages payable by ETSA Utilities for example as a result of a registered Indigenous Land Use Agreement (ILUA), a consent determination or a decision of a Court; and/or*

- l*egal fees and disbursements associated with negotiation and litigation in relation to native title claims.*

A **retailer of last resort obligation event** occurs if:

a) ETSA Utilities is called upon to act as a retailer of last resort under section 23 of the Electricity Act 1996 (SA); and

b) as a consequence, ETSA Utilities incurs costs which it will not otherwise recover.

For the avoidance of doubt, this includes payments made to a retailer(s) where ETSA Utilities has contracted its ROLR obligations to that retailer.

15.5.2 General nominated pass through event

The AER nominates the following general pass through event for ETSA Utilities:

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 draft decision

'CPRS event' in this draft decision

'feed–in tariff event' in this draft decision

'native title event' in this draft decision

For the purposes of this definition,

'material' means the costs associated with the event would exceed 1 per cent of the smoothed forecast revenue specified in the final 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 ETSA Utilities should not be nominated as specific nominated pass through events. However, if the event occurs, the AER notes that ETSA Utilities 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 an event has occurred.

In assessing an application for a cost pass through event (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 ETSA Utilities recovers only incremental costs, and the efficiency of ETSA Utilities' decisions and actions in relation to the event, including whether ETSA Utilities 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 ETSA Utilities for the next regulatory control period are the:

- smart meter event
- CPRS event
- feed–in tariff event
- native title event
- retailer of last resort 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 ETSA Utilities for the provision of standard control services for each year of the next regulatory control period. It also sets out the X factors to be applied as part of the weighted average price cap (WAPC) to apply to the standard control services provided by ETSA Utilities.

16.1 AER draft decision

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

The draft decision resulted in a total revenue requirement for the next regulatory control period of $3549 million, compared to $3720 million proposed by ETSA Utilities. The main reasons for the reduction were:[872]

- the removal of the $243 million from ETSA Utilities' opening regulatory asset base (RAB)
- the removal of the $638 million from ETSA Utilities' forecast capex
- the removal of the $131 million from ETSA Utilities' forecast opex.

The real price changes (as represented by the X factors) were significantly affected by the AER's revised energy forecasts, which were higher than those forecasts proposed by ETSA Utilities. The real price increases were reduced by the higher energy forecasts, with ETSA Utilities' revenue requirement recovered over a greater volume of forecast energy consumption.

The building blocks and the X factors are shown in table 16.1.

[872] AER, *Draft decision, SA draft distribution determination,* November 2009, p. 418.

Table 16.1: AER draft decision on ETSA Utilities' annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation	100.3	113.1	126.6	142.4	157.9
Return on capital	277.5	300.3	327.9	350.9	373.7
Operating expenditure	192.3	204.6	216.8	232.7	244.3
Tax allowance	31.9	33.0	32.4	34.0	35.2
Capex carryover	8.4	7.6	4.3	0.1	0.0
Annual revenue requirements	610.4	658.6	708.0	760.3	811.3
Expected revenues	616.4	653.2	703.9	756.8	818.4
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors (%)	–10.95	–3.90	–3.90	–3.90	–3.90

Source: AER, *Draft decision, SA draft distribution determination,* November 2009, p. 419.

16.2 Revised regulatory proposal

ETSA Utilities proposed a total revenue requirement for the next regulatory control period of $3793 million,[873] compared to $3549 million allowed by the AER in the draft decision. The components of ETSA Utilities proposed revenue requirement are shown in table 16.2.

Table 16.2: ETSA Utilities' proposed annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	98.3	112.2	125.9	141.8	157.2
Return on capital[a]	291.0	318.5	350.0	376.4	402.0
Operating expenditure	204.4	218.0	232.0	249.4	262.2
Tax allowance	49.0	50.4	49.4	51.6	53.3
Capex carryover	0	0	0	0	0
Annual revenue requirements	642.7	699.1	757.3	819.2	874.7
Expected revenues	615.7	666.0	744.7	840.9	949.7
Forecast CPI (%)	2.45	2.45	2.45	2.45	2.45
X factors[b] (%)	–15.63	–5.96	–10.50	–10.50	–10.50

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, Revised PTRM.
(a) Includes equity raising costs.
(b) Negative values for X indicate real price increases under the CPI–X formula.

873 ETSA Utilities, *Revised regulatory proposal*, January 2010, Revised PTRM.

ETSA Utilities noted that the draft decision excluded the electricity distribution price determination (EDPD) carryover effect from the building blocks. ETSA Utilities has revised its PTRM in line with the draft decision. However, because ETSA Utilities anticipates a significant carryover to be returned to customers (an estimated $28 million in 2010–11), to derive a smooth price path for customers, the X factors in the first and second year of the next regulatory control period have been calculated such that a constant price increase of about 10.5 per cent is passed on to customers on average each year.[874]

16.3 Submissions

The AER received submissions from the Energy Consumers Coalition of South Australia (ECCSA), the Energy Users Association of Australia (EUAA) and the South Australian Council of Social Service (SACOSS) that raised concern about significant price increases resulting from ETSA Utilities' revised regulatory proposal.[875] The submissions stated that significant price increases would impact stakeholders negatively through increased input costs to businesses and higher inflation for consumers. ECCSA and SACOSS noted that the impacts of distribution price increases are likely to be exacerbated by increasing costs of generation, increasing renewable energy targets and anticipated climate change policies.[876] SACOSS considered that the final decision will affect low income and vulnerable customers disproportionately.[877] The Total Environment Centre (TEC) suggested that underutilisation of demand management is inefficient in the context of 'unnecessary electricity price increases'.[878]

ECCSA stated during 2009–10, ETSA Utilities was able to provide a service that met consumers' expectations while spending, on average, less on opex and capex than the jurisdictional regulator approved.[879] ECCSA also noted a review indicating South Australian consumers were unwilling to pay more for improved service.[880]

The EUAA indicated concern that the price increases in the next regulatory control period are weighted towards the beginning of the period, whereas EUAA members would prefer a 'smoother approach to price increases'.[881] The EUAA also suggested the price impacts of the AER's decision would be clearer if the AER identified how X factors were translated into average distribution network charges.[882]

874 ETSA Utilities, *Revised Regulatory Proposal*, January 2010, p. 217.
875 SACOSS, *Submission to the AER*, February 2010; and EUAA, *Submission to the AER on ETSA Utilities*, February 2010; and ECCSA, *A response*, February 2010.
876 ECCSA, *A response*, February 2010, p. 7; and SACOSS, *Submission to the AER*, February 2010, p. 1.
877 SACOSS, *Submission to the AER*, February 2010, p. iv.
878 TEC, *Submission to the AER on ETSA Utilities*, February 2010, p. 2.
879 ECCSA, *A response*, February 2010, p. 47.
880 McGregor Tan Research for ESCoSA, *Consumer Preference for Electricity Service Standards*, November 2007.
881 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, p. 7.
882 EUAA, *Submission to the AER on ETSA Utilities*, February 2010, p. 9.

16.4 Issues and AER considerations

16.4.1 Proposed price increases and X factors

The X factors proposed by ETSA Utilities represent the real change in distribution network charges for each year of the next regulatory control period.[883] The impact on retail electricity prices can be estimated by assuming that distribution network charges make up a certain proportion of overall retail electricity prices. Consistent with its draft decision, the AER has assumed distribution network charges make up 40 per cent of retail electricity prices.

Table 16.3 lists the real percentage increases in retail electricity prices which result from ETSA Utilities' proposed X factors. As discussed in chapter 4 of this decision, distribution network charges will be adjusted annually for actual inflation.

Table 16.3: ETSA Utilities' proposal - real increases in retail electricity prices (percentage, per annum)

	2010–11	2011–12	2012–13 to 2014–15
Real price change	6.3	2.4	4.2

Note: Calculation assumes distribution network charges make up 40 per cent of retail electricity prices.

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 DNSPs' 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. Matters raised by interested parties in terms of price-quality trade off and the use of demand management initiatives are addressed in the context of the individual building blocks and the relevant chapters of this decision.

- 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 addressing the concerns of some submitters regarding the size of the price impact in the first year of the next regulatory control period. The AER's decision with regard to smoothing price changes is set out in section 16.5 of this decision.

- for standard control services equalise, in 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 PTRM are designed to achieve this outcome.

[883] Notwithstanding any unders/over adjustments related to previous year outcomes. See chapter 4 for discussion on the various unders/overs adjustment that can occur annually.

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.

In response to submissions from interested parties in relation to higher electricity prices, the potential negative effects on businesses and detrimental social consequence for vulnerable consumers, it should be recognised that the revenue requirement allowed for in this decision 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 target, for example, businesses or vulnerable customers over other consumers of electricity.

The AER also can not influence how the changes to distribution network charges flow through to retail prices. The AER has made a broad assumption that distribution network prices make up 40 per cent of the retail electricity price to estimate how distribution network charges will flow through to retail electricity prices. The AER’s decision on ETSA Utilities’ X factors and the resulting effect on retail electricity prices are presented in section 16.5.

The AER will assess ETSA Utilities’ proposed price changes annually. 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. These requirements will be assessed by the AER as part of the distribution price approval process.

16.4.2 Accuracy of existing prices and forecast sales quantities

The AER has examined the accuracy of the pricing inputs to the revised PTRM for 2009–10 in terms of whether they reflect the prices approved by ESCOSA. This is important as these prices provide the starting point from which the X factors (which represent the real price changes) will be determined in the PTRM under the WAPC.

The AER found that the pricing information provided by ETSA Utilities was accurate.[884]

The AER also examined the forecast energy and customer number data submitted by ETSA Utilities. As discussed in chapter 6, the AER engaged MMA to review ETSA Utilities' proposed customer numbers, while AEMO was engaged to review ETSA Utilities' energy forecasts. MMA considered ETSA Utilities' forecasts of customer numbers were reasonable. The AER considered and accepted these forecasts.

However, AEMO had concerns about ETSA Utilities' quantity forecasts. As discussed in chapter 6, the AER agreed with AEMO's assessment and requested updated quantity data (down to the tariff component level) from ETSA Utilities which has been incorporated into this decision. The revised energy forecasts provided by ETSA Utilities reflected AEMO's forecasts plus an adjustment for the impact of higher prices resulting from this decision on expected energy use.

16.4.3 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 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.

16.4.4 Asset base roll forward and indexation

As discussed in chapter 5, the AER determined the opening value of ETSA Utilities' RAB as at 1 July 2010 to be $2772 million. The AER rolled forward ETSA Utilities' RAB for the next regulatory control period using the PTRM, as shown in table 16.4.

Table 16.4: AER's forecast roll-forward of ETSA Utilities' regulatory asset base ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Opening RAB	2772.4	2999.6	3263.9	3482.5	3696.3
Net capex[a]	327.4	377.6	345.4	356.3	361.3
Indexation of the opening RAB	69.9	75.6	82.2	87.8	93.1
Straight-line depreciation	–170.1	–188.9	–209.0	–230.3	–250.8
Closing RAB	2999.6	3263.9	3482.5	3696.3	3899.8

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. This capex also includes capitalised equity raising costs.

[884] ETSA Utilities' revised PTRM also reflected the AER's draft decision to treat certain metering services as alternative control services, with the associated revenues for these services removed from the PTRM for standard control services.

16.4.5 Depreciation

As discussed in chapter 10, the AER has not approved ETSA Utilities' 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 (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 16.6 shows the resulting allowance.

16.4.6 Return on capital

The AER considers that ETSA Utilities' 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 ETSA Utilities' opening RAB for each year of the next regulatory control period. The approved return on capital allowances are shown in table 16.6.

The nominal vanilla WACC of 9.72 per cent is based on a post–tax nominal return on equity of 11.09 per cent and a pre–tax nominal return on debt of 8.87 per cent. These figures are calculated using observed market data for ETSA Utilities' nominated averaging period ending 23 April 2010.

16.4.7 Operating expenditure

Opex is discussed in chapter 8. The AER has determined a forecast opex allowance for ETSA Utilities of $1115 million (nominal) over the next regulatory control period. Table 16.6 shows the annual opex allowances.

16.4.8 Estimated tax payable

As discussed in chapter 9, using the PTRM the AER modelled ETSA Utilities' benchmark income tax liability for 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 ETSA Utilities' actual gearing
- a statutory company income tax rate of 30 per cent as determined by the AER, and
- 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 PTRM, the AER has derived an effective tax rate of 42.0 per cent for this decision. Table 16.5 shows the AER's estimate of ETSA Utilities' net tax allowance.

Table 16.5: AER decision on ETSA Utilities' net tax allowance ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014-15
Tax payable	92.4	93.3	91.5	95.9	98.8
Value of imputation credits	–60.1	–60.6	–59.5	–62.4	–64.2
Net tax allowance	32.3	32.6	32.0	33.6	34.6

16.4.9 Revenue decrements arising from the previous periods control mechanism

In the draft decision, the AER rejected ETSA Utilities' proposal to include a forecast for the transitional amounts (associated with the transitional ($EDPD_t$) factor in the WAPC) in determining the X factors in the PTRM. Instead, the AER considered the $EDPD_t$ factor should be applied independent of the X factor and based on actual results for the various components that make up the $EDPD_t$ factor.[885]

In its revised regulatory proposal, while not including the EDPD amount as a building block component, ETSA Utilities did amend its X factors in an attempt to smooth the impact of the expected EDPD amount in 2010–11. The AER remains of the view that the annual under/over adjustments should be applied independent of the X factor and based on actual results for the various components that make up the $EDPD_t$ factor. The AER's reasons set out in the draft decision for rejecting ETSA Utilities' regulatory proposal on this matter remain valid.[886] In this regard, the AER considers an adjustment term would still be required in the control mechanism for any difference between the forecast EDPD adjustment and the actual outcome. The AER notes that its approach will not cause price fluctuations from one year to the next, as only price increases have been determined for the next regulatory control period (see section 16.5).[887] The AER also notes that its approach regarding under/overs adjustments related to the current regulatory control period has been accepted by the Qld DNSPs.

ETSA Utilities will need to provide the actual EDPD amounts (and a demonstration of how they were calculated) as part of its pricing proposal.

16.5 AER conclusion

The AER calculates ETSA Utilities' annual revenue requirements and X factors based on its decisions regarding the building blocks as shown in table 16.6.

885 AER, *Draft decision, SA draft distribution determination,* November 2009, p. 50.
886 AER, *Draft decision, SA draft distribution determination,* November 2009, p. 50.
887 These price increases exceed the EDPD amount forecast by ETSA Utilities.

The AER's decision results in a total revenue requirement for the next regulatory control period of $3525 million ($nominal), compared to $3793 million proposed by ETSA Utilities. The main reasons for the reduction are:

- the removal of $131 million from ETSA Utilities' opening RAB. This amount relates to the revaluations ETSA Utilities made to its RAB for easements, the reinstatement of capital contributions that the AER disallowed and an updated CPI figure for 2009–10.
- the removal of $217 million from ETSA Utilities' forecast capex
- the removal of $51 million from ETSA Utilities' forecast opex
- the removal of $88 million from ETSA Utilities' proposed tax allowance, reflecting in part a higher gamma than that proposed by ETSA Utilities
- a lower WACC than that proposed by ETSA Utilities.

Table 16.6: AER conclusion on ETSA Utilities' annual revenue requirements and X factors ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Regulatory depreciation[a]	100.2	113.3	126.8	142.5	157.7
Return on capital[a]	270.5	292.7	318.5	339.8	360.7
Operating expenditure[b]	197.9	209.6	221.8	237.4	248.7
Tax allowance	32.3	32.6	32.0	33.6	34.6
Capex carryover[c]	8.6	7.9	4.5	0.4	0.0
Annual revenue requirements	609.6	656.1	703.6	753.7	801.7
Expected revenues	619.7	656.9	695.8	745.9	804.0
Forecast CPI (%)	2.52	2.52	2.52	2.52	2.52
X factors (%)[d]	–12.14	–5.75	–5.75	–5.75	–5.75

(a) Includes equity raising costs.
(b) Includes demand management innovation allowance, self insurance and feed-in tariffs.
(c) This adjustment is discussed in chapter 13.
(d) Negative values for X indicate real price increases under the CPI–X formula.

As discussed above, in deciding on ETSA Utilities' X factors, the AER has not recognised the forecast impact of any carry over adjustments from the current regulatory control period. Accordingly, the AER has adopted the approach used for the draft decision and applied a separate X factor (Po) for the first year of the next regulatory control period and then held the X factor constant for the remaining years of the next regulatory control period. Using this approach, the AER revised ETSA Utilities' X factor for 2010–11 from –15.63 per cent to –12.14 per cent, the X factor for

2011–12 from –5.96 per cent to –5.75 per cent and the X factors for the remaining years of the next regulatory control period from –10.50 per cent to –5.75 per cent.

The sizes of the X factors were affected by the revised energy forecasts (as discussed in chapter 6), which lowered the expected per unit price increases marginally.

The impact of the AER's decision on retail prices, compared with ETSA Utilities' revised regulatory proposal, is outlined in table 16.7.

Table 16.7: Retail price impacts (%)

	2010–11	2011–12	2012–13	2013–14	2014-15
ETSA Utilities regulatory proposal					
Real impacts	6.3	2.4	4.2	4.2	4.2
Nominal impacts	7.4	3.5	5.3	5.3	5.3
AER decision					
Real impacts	4.9	2.3	2.3	2.3	2.3
Nominal impacts	6.0	3.4	3.4	3.4	3.4

Note: Calculations assume distribution network charges make up 40 per cent of retail electricity prices. Inflation of 2.52 per cent assumed for calculating the nominal impacts.

The price impacts above exclude the effect of any annual adjustments for such matters as the transitional $EDPD_t$ factor 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 does not approve the annual revenue requirement proposed by ETSA Utilities.

In accordance with clauses 6.12.1(2)(ii) and 6.3.2(a)(4) of the NER, ETSA Utilities' 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 ETSA Utilities are as specified in table 16.6 of this decision.

In accordance with clause 6.3.2(a)(1) of the NER, ETSA Utilities' annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.6 of this decision.

In accordance with clause 6.3.2(a)(2) of the NER, an appropriate methodology for indexation of ETSA Utilities' regulatory asset base is as specified in section 16.4.5 of this decision.

In accordance with clause 6.3.2(a)(5) of the NER, any other amounts, values or inputs on which ETSA Utilities' building block determination is based are as specified in sections 16.4 and 16.5 of this decision.

17 Alternative control services

This chapter sets out the AER's consideration of ETSA Utilities' alternative control services control mechanism and how compliance with that mechanism is to be demonstrated in the next regulatory control period. The alternative control services are variable standard small customer metering services and exceptional large customer metering services as set out in appendix A of this decision.

No submissions were received on this issue.

17.1 AER draft decision

The AER stated it will apply a separate weighted average price cap (WAPC) control mechanism to alternative control services, as set out in the AER's framework and approach. The AER noted ETSA Utilities indicated that it may reconsider some of the assumptions underlying its proposal, however, it was also the case that stakeholders had no opportunity to comment on ETSA Utilities' proposal.[888] The AER stated it will assess the building block components of the control mechanism based on the revised regulatory proposal and submissions from interested parties.[889]

The AER stated ETSA Utilities was required to demonstrate compliance with the WAPC by providing, as part of its pricing proposal, the proposed tariffs which correspond to the price terms contained in the WAPC formula approved by the AER.[890]

17.2 Revised regulatory proposal

ETSA Utilities considered the draft decision classifying alternative control metering services to be inappropriate, but incorporated the alternative control metering services control mechanism consistent with the draft decision in its revised regulatory proposal. It also accepted that compliance with the control mechanism will be demonstrated by providing metering tariffs as part of its annual pricing proposal.[891]

Control mechanism

ETSA Utilities stated that in order to implement the new approach it developed one alternative control metering tariff class with six operationally practical cost reflective meter provision tariffs (tariff components). However, it stated its current billing systems require the implementation of an interim solution with a lesser number of tariff components and it will only be able to adopt three alternative control metering tariff components on 1 July 2010. ETSA Utilities also stated that its existing systems

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[888] In its regulatory proposal, ETSA Utilities did not provide the alternative control services control mechanism consistent with the AER's framework and approach paper. However, during the assessment process prior to the draft decision the AER requested that ETSA Utilities provide its alternative control services control mechanism. ETSA Utilities complied with this request.

[889] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 421–427.

[890] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 427.

[891] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 45.

will need to be modified during the first year of the next regulatory control period to implement an ongoing solution.[892]

ETSA Utilities stated that in order to comply with the WAPC set out in the framework and approach paper it developed notional 2009–10 metering alternative control tariffs. It stated that these prices were set to derive notional 2009–10 metering alternative control revenues of $15.7 million.[893] ETSA Utilities' proposed tariff components and notional 2009–10 prices are shown in table 17.3.

ETSA Utilities stated the customer number forecast for alternative control metering services is based on the customer numbers underpinning its revised regulatory proposal.[894]

ETSA Utilities stated the WAPC for alternative control metering services includes minor changes to preserve consistency with the WAPC applied for standard control services.[895]

Opening asset value

ETSA Utilities proposed an opening asset value of the alternative control metering services asset base of $80.2 million and the opening tax asset value of $58.8 million.[896]

Forecast capex

ETSA Utilities' proposed alternative control metering services forecast capex is set out in table 17.1.

Table 17.1: ETSA Utilities proposed forecast capex ($m, June 2010)

	2010–11	2011–12	2012–13	2013–14	2014–15
Capex	11.82	12.66	11.34	12.16	11.96

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 110, table 6.10.

Exit charges

ETSA Utilities proposed that the exit fee should equal the sum of the average written down value of the existing customer's meter. It stated that by recognising the asset component of this fee as a capital contribution, the integrity of the building block model would be preserved and the capital costs associated with these meters will not continue to be recouped.[897] The proposed exit charges capital cost components are shown in table 17.3. In addition, ETSA Utilities proposed a $60 fee per terminating

892 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 45.
893 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 218.
894 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D1, p. 8.
895 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 45.
896 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 186 and 210.
897 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 46.

customer to cover the marginal back office cost of facilitating the transfer of the terminating customer in its systems.[898]

Building block elements

The proposed building block elements are set out in table 17.2. ETSA Utilities applied a nominal vanilla WACC of 10.02 per cent consistent with the draft decision. ETSA Utilities has proposed a 50 per cent value for imputation credits. Table 17.2 also sets out ETSA Utilities' annual revenue requirement and proposed X factors. It proposed that the X factors for each year of the regulatory control period be made equal to deliver a smooth price path.[899]

Table 17.2: ETSA Utilities proposed building block revenue requirements ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Return on capital	8.04	8.95	9.86	10.58	11.33
Return of capital	3.64	4.42	5.28	6.14	7.11
Operating expenditure	6.57	6.81	7.18	7.59	8.04
Tax	0.72	0.83	0.95	1.07	1.19
Annual revenue requirement [a]	18.97	21.00	23.27	25.37	27.67
X factors [b] (percentage)	–9.18	–9.18	–9.18	–9.18	–9.18

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 216–217, tables 16.5 and 16.7.
(a) Unsmoothed annual revenue requirement.
(b) Negative values for X indicate real price increases under the CPI–X formula.

Indicative prices

Indicative prices provided by ETSA Utilities in its revised regulatory proposal are set out in table 17.3.

[898] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D1, p. 3.
[899] ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 217.

Table 17.3: ETSA Utilities metering services indicative tariffs ($2009–10)*

Metering service	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Meter provision type 6 DCC ($/day)	0.05246	0.05728	0.06254	0.06837	0.07472	0.08164
Meter provision type 6 current transformer connected ($/day)	0.23249	0.25383	0.27714	0.30299	0.33115	0.36183
Meter provision type 1–4 exceptional ($/day)	0.81508	0.88992	0.97163	1.06227	1.16097	1.26854
Meter service other meter provider customer ($/day)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Meter service exit fee type 6 (CTC) ($)	344.15	344.15	344.15	344.15	344.15	344.15
Meter service exit fee type 1–4 ($)	667.97	667.97	667.98	667.98	667.98	667.98

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 219, table 16.10.
*GST exclusive

Compliance with the WAPC

ETSA Utilities stated it will demonstrate compliance with the control mechanism by annually providing the proposed tariffs that correspond to the price terms contained in the WAPC approved by the AER.[900]

ETSA Utilities stated it needed to adopt an interim arrangement with a limited number of tariff components because of billing system limitations and that it may require changes to the metering tariffs in the next regulatory control period to improve the cost reflectivity. ETSA Utilities therefore requested that the AER apply the reasonable estimates approach to tariff changes relating to alternative control services similar to the approach stated in appendix E of the draft decision.[901]

17.3 Issues and AER considerations

ETSA Utilities is required to offer alternative control metering services for the first time in the next regulatory control period. Therefore, this will be the first time that an alternative control metering tariff class is used by ETSA Utilities and a WAPC control mechanism is applied to that tariff class. In the current regulatory control period, the costs of the metering services that are now classified as alternative control services were recovered by the distribution use of system (DUOS) charge.

17.3.1 Control mechanism

The control mechanism applicable to ETSA Utilities is the WAPC as set out in section 17.4.

900 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 218.
901 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 45.

The AER notes that it does not assess individual tariffs for the next regulatory control period rather it approves compliance with the WAPC as part of this determination. Consistent with Part I of chapter 6 the NER, the review of annual tariffs will be undertaken as part of the AER's review of ETSA Utilities' pricing proposal. However, the AER has assessed the reasonableness of ETSA Utilities' pricing methodology used to derive 2009–10 notional pricing as 2009–10 prices are an essential input to the PTRM to assess compliance with the WAPC.

ETSA Utilities stated that its objective when developing tariff components and notional 2009–10 prices was to achieve cost reflective and operationally practical tariff components.[902]

17.3.1.1 Tariff components

ETSA Utilities has reviewed its list of meter panel installations based on its installation rules and staff discussions to develop a list of 14 typical metering installations. These 14 types of meter installations were then aggregated into 6 standard tariff components for which it considered that meter provision tariffs could be developed. The AER notes that in aggregating these 6 tariff components, ETSA Utilities has taken account of the cost relativities between these 14 typical metering installations. These cost relativities were based on the notional prices developed by ETSA Utilities (section 17.3.1.2). The AER considers it reasonable that ETSA Utilities derive prices that achieve cost reflectivity. To this end, aggregating the 14 meter types into 6 tariff components based on cost relativities consistent with its stated objective of achieving cost reflective prices is a reasonable approach. These 6 tariff components are set out in table 17.4.

Table 17.4: ETSA Utilities tariff components for next regulatory control period

Tariff component
Meter provision – standard single phase, 1 rate
Meter provision – standard single phase, 1–2 rate with controlled load and/or off-peak
Meter provision – standard multi-phase, direct connected
Meter provision – standard multi-phase, direct connected with controlled load and/or off-peak
Meter-provision – standard multi-phase, current transformer connected
Meter provision – exceptional type 1–4 meters

Source: ETSA Utilities *Revised regulatory proposal,* January 2010, attachment D1, table D.1.2.

First regulatory year tariff components

The AER notes ETSA Utilities' explanation that its billing system as it currently exists can only accommodate four tariff components for automated processing and

[902] ETSA Utilities, *Revised regulatory proposal,* January 2010, attachment D1, p. 4.

that one of those will need to accommodate a 'no meter' tariff to recognise customers using other meter providers.[903]

The AER's framework and approach, set out the classifications and control mechanisms for ETSA Utilities' distribution services.[904] Clause 6.12.3 of the NER provides that the classification of services in the distribution determination be the same as that set out in the framework and approach unless there are good reasons for the AER to depart from that classification. Clause 6.12.3 also provides that the control mechanism must be the same as that set out in the framework and approach. For these reasons the AER expected the regulatory proposal would be consistent with the control mechanism set out in the framework and approach. The AER, however, notes that although, ETSA Utilities in its regulatory proposal proposed a reclassification of the alternative control metering services (and did not provide a separate WAPC), it also proposed a pricing solution which included separate tariff components. That pricing solution underpinned the tariff component methodology in the revised regulatory proposal.

Nonetheless, the AER accepts ETSA Utilities' explanation that in the absence of an automated system, the implementation of its proposed six cost reflective tariff components would involve a manual process which is unworkable.[905] The AER considers that in these circumstances it is reasonable for ETSA Utilities to initially apply its available automated billing system to implement alternative control metering services, at least in the early part of the next regulatory control period. That is, ETSA Utilities will only apply three alternative control metering tariff components (and one 'no meter' component) in the first year of the next regulatory control period.

The AER considers that ETSA Utilities' methodology based on the weighted average of the four direct current connected (DCC) meter tariff components (the first four components in table 17.4) using customer numbers as weights to be a reasonable approach to developing the single DCC tariff component.[906] The AER notes that adopting one tariff component that best reflected cost relativities between the tariffs also enabled ETSA Utilities to adopt explicitly cost reflective prices for the remaining two tariff components, which are the two meter installation types that are subject to most amount of customer churn (the last two components in table 17.4).[907] The AER acknowledges that this transitional step in the first year, although adopting a reduced number of tariff components, allows competition to develop in the two meter installation types that are most subject to potential competition. That is, standard multi-phase current transformer connected and exceptional type 1–4 meters.

The three alternative control metering tariff components in the first year of the next regulatory control period are:

- alternative control meter provision type 6 DCC (ACS MP-DCC)

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903 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D1, p. 4.
904 AER, *Final decision, Framework and approach paper, ETSA Utilities*, November 2008.
905 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D1, p. 4.
906 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 61–ACS and NS classification, tariffs-quantities-costs, TariffsB 2009–10 tab.
907 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 61–ACS and NS classification, tariffs-quantities-costs, TariffsB 2009–10 tab.

- alternative control meter provision type 6 current transformer connected (ACS MP-CTC)

- alternative control meter provision type 1–4 exceptional.

ETSA Utilities confirmed that its system changes are expected to be completed during 2010–11 enabling it to transition to the six tariff components shown in table 17.4 in time to include them in its 2011–12 pricing proposal.[908] The AER notes that ETSA Utilities has an incentive to implement the system changes by the stated date as non implementation would result in it having to adopt a non-automated approach to applying the six tariff components.

17.3.1.2 Notional 2009–10 pricing

ETSA Utilities adopted the following methodology to derive its 2009–10 notional pricing for alternative control meter provision services:

- Step 1 — 14 typical metering installations were developed.

- Step 2 — variable capital costs for each of the typical metering installations were developed based on replacement costs (materials costs) and variable installation costs (estimated electric mechanic's time multiplied by average hourly rate).

- Step 3 — the annual variable capital cost for each typical meter was derived on an annuity basis applying the estimated standard life and the real vanilla WACC to the capital costs developed in step 2. Consistent with the discussion in section 17.3.1.1 the 14 typical meters were aggregated to 6 tariff components based on cost relativities.

- Step 4 — the December 2009 forecast national meter identifier (NMI) numbers were allocated to relevant meter tariff components. Annual variable operating costs associated with each meter type was calculated by assessing the operating cost relativities for each meter tariff component on a per meter basis.

- Step 5 — type 6 meter reading costs were calculated by dividing the 2010–11 meter reading costs by the total number of type 6 NMIs estimated by ETSA Utilities.[909]

The AER assessed the material costs and installation costs adopted by ETSA Utilities and found these to be reasonable for the purpose of developing notional cost reflective prices and notional revenues for the year 2009–10.

In developing the variable operating costs per meter type, ETSA Utilities has taken account of unique identifiable costs that should be allocated to specific types of meters. ETSA Utilities identified material unique costs associated with current transformer connected meters and type 1–4 meters and allocated those costs to the relevant meter type. These unique cost requirements are associated with

[908] ETSA Utilities, response to information request AER.EU.RP.7, 23 February 2010, p. 6.
[909] ETSA Utilities, *Revised regulatory proposal,* January 2010, attachment D1, pp. 4-6, and, RIN 60– Notional 2009–10 ACS metering tariff prices.

communications fault attendance and meter inspection and testing. Where such unique operational cost relativities are not present, ETSA Utilities apportioned the total opex evenly across all meter types after adding a factor to take account of added complexity of maintaining meters other than standard single phase single-rate meters.[910]

The AER accepts ETSA Utilities' proposal to divide meter reading costs by the total number of relevant NMIs as at 2009–10 to derive the per meter annual meter reading costs (the energy data service component of the alternative control metering service). This approach is reasonable as it would attribute the costs directly to the relevant user. The annual meter reading costs for the next regulatory control period is $4.56 per annum ($June 2010).

ETSA Utilities derived its 2009–10 notional revenue requirement (to populate the PTRM) by multiplying the notional 2009–10 pricing by its 2009–10 estimated customer numbers for the specific meter type.

The AER considers ETSA Utilities' approach based on cost reflectivity to calculating its notional 2009–10 alternative control metering prices to be reasonable.

17.3.1.3 Customer numbers

ETSA Utilities' customer number forecasts are based on the figures and underlying methodology provided as part of its regulatory proposal and which was accepted in the draft decision.[911] The AER considers that the proposed customer number forecasts of alternative control metering services are based on the draft decision and therefore are reasonable.

Given that ETSA Utilities does not currently have precise data that assigns metering types to individual NMIs, the total customer numbers were allocated by it across meter types on a pro-rata basis consistent with the proportion of estimated meter types.

The AER accepts ETSA Utilities' proposed approach to allocate customer numbers across the tariff components on a pro-rata basis as the tariff components were based on the different meter types. ETSA Utilities provided its calculation and allocation of customers across the different tariff components.[912] It also provided a reconciliation showing its total customer numbers with metering services customers.[913] The forecast customer numbers per tariff component in the next regulatory control period are set out in table 17.5.

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910 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 60–Notional 2009–10 ACS metering tariff prices, opex tab modelling.

911 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 97.

912 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 61–ACS and NS classification, tariffs-quantities-costs, TariffsB 2009–10 tab.

913 ETSA Utilities, response to information request AER.EU.RP.12, 17 March 2010, p. 6.

Table 17.5: ETSA Utilities forecast meter customer numbers

Tariff component*	2010–11	2011–12	2012–13	2013–14	2014–15
ACS-MP T6 1ph 1r	431 675	449 715	467 106	483 855	500 550
ACS-MP T6 1ph 1-2r yCL	204 008	193 928	183 720	173 386	163 042
ACS-MP T6 3ph 1-2r nCL	129 099	132 748	137 180	141 429	145 662
ACS-MP T6 ODC	47 744	45 328	42 883	40 409	37 932
ACS-MP T6 CTC	3390	2993	2637	2317	2036
ACS-MP T 1-4 ICTC+C	675	505	377	281	209
Other meter provider's customers	5444	6385	7196	7896	8508
Alternative control metering customers	822 036	831 601	841 100	849 573	857 940

* The first six tariff components represent those described in more detail in table 17.4.
Source: ETSA Utilities, response to information request AER.EU.RP.7, 23 February 2010, attachment 1.xls.

For the reasons discussed in section 17.3.1.1 and accepted by the AER, ETSA Utilities aggregated the DCC customers into one tariff component for the purposes of modelling X factors and indicative prices in the PTRM.

Exiting customer numbers

ETSA Utilities' forecast customer numbers exiting the meter provision services over the next regulatory control period for current transformer connected type 6 meters (CTC type 6) and type 1–4 meters using its meter customer churn rates over the period 2006–09.[914] ETSA Utilities only provided forecast exiting customer numbers for these two tariff components as it intends to charge exit fees only to customers exiting installations that are subject to these two tariffs.

ETSA Utilities' analysis showed that the weighted average growth rates during the period under review for large customers and type 1–4 meters were negative 14 and 27 per cent respectively. It reasoned that the large customer growth rate was appropriate to be applied to customers on CTC type 6 meters as these customers were generally the largest small customers. It further reasoned that type 1–4 meter growth rates were appropriate to be applied to customers on exceptional type 1–4 meters. Applying these growth rates to customers on these two types of meter installations resulted in an annual reduction in customer numbers. The AER considers ETSA Utilities proposed customer churn is a reasonable approximation given the available data, and should be used for the next regulatory control period to forecast customer numbers using these meter types.

The AER considers that the methodology developed by ETSA Utilities based on actual past customer churn to be an appropriate methodology to derive forecast

[914] ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 62 – Large customer attrition expectations.

exiting customer numbers. The forecast exiting customer numbers for the two relevant tariff components in the next regulatory control period proposed by ETSA Utilities is reasonable and are set out in table 17.6.

Table 17.6: Exiting customer forecasts (customer numbers)

	2010–11	2011–12	2012–13	2013–14	2014–15
Type 6 CTC	444	397	356	320	281
Type 1–4 exceptional	228	170	128	96	72

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 61–ACS and NS classification, tariffs-quantities-costs.

17.3.1.4 Changes to the WAPC

For the reasons discussed in section 4.5.3.1 of the draft decision, the AER accepts ETSA Utilities' proposed minor changes to the WAPC formula to preserve consistency with the WAPC for standard control services.[915] The applicable WAPC formula is shown in section 17.4 of this decision.

17.3.2 Opening asset value

The next regulatory control period is the first time that ETSA Utilities will offer alternative control metering services. The control mechanism requires that the X factor be determined using the building block approach. Therefore, ETSA Utilities is required to provide a separate alternative control services regulated asset base (RAB).

ETSA Utilities provided a separate roll forward model (RFM) for alternative control metering services for the current regulatory control period which incorporated the opening asset value as at 1 July 2005. Under ESCOSA's price determination applicable in the current regulatory control period, metering assets were included in the low voltage services (LVS) assets category for regulatory purposes. Therefore ETSA Utilities was obliged to separate its metering assets from the LVS opening asset value to develop its RFM for alternative control metering services. ETSA Utilities advised that for accounting purposes it had separated metering assets from the LVS assets since 2003–04. It proposed to separate metering assets based on the actual metering capex as a proportion of LVS capex based on accounting data for the periods 2003–04 to 2007–08.[916] The AER is satisfied that the methodology adopted by ETSA Utilities to separate metering assets from the LVS asset category based on the proportions of actual capex derived from its accounting data is reasonable.

ETSA Utilities provided the proportions of actual capex data for LVS and metering assets.[917] Based on its methodology ETSA Utilities adopted an opening asset value as at 1 July 2005 of $48.75 million. The AER considers this value to be reasonable given

915 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 50.
916 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D1, pp. 1–2.
917 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 64–ACS metering supporting schedule.

that it was derived by applying an acceptable methodology to separate metering assets from the LVS assets.

In its RFM, ETSA Utilities applied an asset life of 30 years, consistent with asset lives adopted to depreciate LVS assets in the current regulatory control period. The AER has reviewed ETSA Utilities' proposed opening RAB and the cost inputs to the RFM and is satisfied that it has been completed correctly. The AER updated the RFM with the actual CPI rate of 2.89 per cent for the period 2009–10. The roll forward of the alternative control metering services asset base is set out in table 17.7.

The AER accepts ETSA Utilities' proposal to reduce the opening RAB as at 1 July 2010 derived from the RFM by an amount of $0.34 million (June 2010) for the value of metering assets providing negotiated distribution services. The alterative control metering services opening RAB at 1 July 2010 is $80.65 million.

Table 17.7: AER conclusion on the alternative control metering RAB ($m, nominal)

	2005–06	2006–07	2007–08	2008–09	2009–10*
Opening RAB	48.75	54.12	58.81	66.26	73.32
Actual capex (adjusted for actual CPI and WACC)	7.34	7.13	9.07	10.01	10.61
Straight-line depreciation (adjusted for actual CPI)	1.96	2.45	1.61	2.96	2.93
Closing RAB	54.12	58.81	66.26	73.32	80.99
Negotiated metering services deduction					–0.34
Opening RAB at 1 July 2010					80.65

* Based on estimated net capex

17.3.3 Capex

ETSA Utilities' forecast metering capex is derived from its LVS capex proposed in its regulatory proposal. The proportion of metering capex to be removed from the LVS assets forecast capex has been calculated by determining the actual metering capex during the period 2006 – 2008 derived from accounting records. As per this historical data, the metering capex is on average 19.1 per cent of the LVS capex. ETSA Utilities has applied this same percentage to separate forecast metering capex from LVS capex in the next regulatory control period.[918] The AER considers this approach to separating metering capex from the LVS capex based on proportions derived from actual historical capex is reasonable. The approved net capex allowance is set out in table 17.8.

The AER notes that no specific issues relating to LVS capex (inclusive of metering) were identified by PB in its review of ETSA Utilities' capex proposal and that the draft decision accepted that aspect of ETSA Utilities' capex proposal.

[918] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F1, tab R8, table 4.

17.3.3.1 Equity raising costs

ETSA Utilities proposed equity raising costs of $0.39 million. The AER assessed ETSA Utilities' alternative control metering services equity raising cost calculations.[919] For the reasons stated in section 7.4.7 of this decision, the AER considers that ETSA Utilities equity raising costs calculation is inappropriate.

Consistent with its conclusions on the equity raising costs for this decision, the AER has allowed ETSA Utilities equity raising costs of $0.36 million. This amount is $0.03 million less than ETSA Utilities' proposed equity raising costs.

17.3.3.2 Input cost escalation

ETSA Utilities confirmed that real cost escalators consistent with the broader capex category were applied to metering capex.[920] The AER considers it reasonable to apply the same real cost escalators to metering capex as those applied to the general capex category.

The AER's decision on input cost escalators is set out in appendix G. Applying the AER' decision to ETSA Utilities' alternative control metering forecast capex results in annual reductions as set out in table 17.9.

17.3.3.3 Exit charge –capital cost component

The AER clarified its classification of alternative control meter provision services definition to recognise exit charges.[921]

The AER accepts ETSA Utilities' proposal to charge exit fees only on two tariff components. That is, exit charges in the next regulatory control period will be applicable only to customers on CTC type 6 tariffs or type 1–4 exceptional tariffs. The AER recognises ETSA Utilities' explanation that the CTC type 6 tariff component generally applies to the largest type 6 customers.[922] The AER understands ETSA Utilities' proposal and reasoning to mean that in the next regulatory control period it will not be levying exit charges on alterative control metering services customers other than those on CTC type 6 and type 1–4 exceptional tariffs.

ETSA Utilities' proposed exit charge includes both a capital cost component and opex cost component. The opex component is discussed at section 17.3.4.3. Table 17.8 sets out ETSA Utilities' proposed exit charge – capital cost component.

ETSA Utilities advised that the exit charge – capital cost component reflects the average written down capitalised value of the type 6 CTC and type 1–4 exceptional meters. The capitalised value is determined based on replacement cost of the asset. On average the asset is assumed to have a 50 per cent residual value at the time of removal from service and no salvage value.

The AER reviewed the meter replacement cost calculations proposed by ETSA Utilities and considers them to be reasonable (see section 17.3.1.2). The AER notes

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919 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 71–Equity raising costs meters.
920 ETSA Utilities, response to information request AER.EU.RP.12, 17 March 2010, p. 2.
921 See section 2.4.1 of this decision.
922 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D1, p. 11.

that the replacement cost is not the most appropriate cost for determining the residual value of assets, particularly where the underlying issue is financial capital maintenance. Generally, using the actual written down value of the asset would be preferred. ETSA Utilities justified its approach on the basis that:[923]

- the administrative costs of determining the actual written down value of an individual meter would be prohibitive, in its circumstances

- it is not possible to determine whether customers with newer meters or older meters would exit the service

- current cost of metering is declining and therefore adopting replacement cost is a conservative approach

- the forecast capital costs of the exit charge will be removed from the regulated asset base and therefore ETSA Utilities will not accrue any windfall loss or gain.

The AER notes the above reasons and, given that ETSA Utilities currently includes metering services as part of DUOS and historically has not recorded metering assets separately, considers ETSA Utilities' replacement cost approach is reasonable. The AER will review this approach after the next regulatory control period.

The AER identified that ETSA Utilities double counted installation costs in developing its exit charge – capital cost component.[924] To calculate the replacement cost of each meter type for the purpose of exit charges, ETSA Utilities used its model which calculated the capital costs of the meter provision service (for 2009–10 notional pricing purposes).[925] This capital cost calculation included both materials and installation costs to derive the replacement costs.[926] The AER's adjustment results in a common replacement cost value being adopted to derive the notional pricing and revenue in 2009–10 and the exit charge – capital cost component. The AER's conclusion on ETSA Utilities' exit charge – capital cost component is set out in table 17.8.

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923 ETSA Utilities, response to information request AER.EU.RP.7, 23 February 2010, p. 3.

924 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 66–Customer expectations and exit fee.

925 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 60–Notional 2009–10 ACS metering tariff prices.

926 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 60–Notional 2009–10 ACS metering tariff prices, Install cost tab.

Table 17.8: AER conclusion on the exit charge – capital cost component ($2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
ETSA Utilities proposal					
Type 6 CTC	276	276	276	276	276
Type 1–4 exceptional	592	592	592	592	592
AER conclusion					
Type 6 CTC	170	170	170	170	170
Type 1–4 exceptional	456	456	456	456	456

Source: ETSA Utilities *Revised regulatory proposal*, January 2010, RIN 66–Customer expectations and exit fee and the AER analysis.

The AER considers ETSA Utilities' proposal to reduce the alternative control regulated asset base by the amount of revenue received from exit charges – capital cost component to be reasonable. As these assets will no longer be in service they should not earn a return on or return of capital (that is an allowance for regulatory depreciation). The AER notes ETSA Utilities' statement that this income is recognised as taxable revenue and therefore considers it reasonable to include these amounts as taxable revenue in the PTRM. In order to accommodate these aspects within the AER's current PTRM, the exit charge – capital costs component revenues are input as capital contributions. ETSA Utilities' forecast customer numbers subject to the exit charge are set out in table 17.6. Adopting these customer numbers and the AER's conclusion on the exit charge – capital costs component, results in the exit charge (capital contribution) amounts in table 17.9.

17.3.3.4 Conclusion

Table 17.9 sets out the AER approved capex allowance for ETSA Utilities alternative control metering services in the next regulatory control period.

Table 17.9: AER conclusion on ETSA Utilities' metering capex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
ETSA Utilities proposed gross capex [a]	12.21	12.66	11.34	12.16	11.96
AER exit charges (capital contributions)	–0.18	–0.15	–0.12	–0.10	–0.08
AER adjustments to cost escalators	–0.345	–0.677	–0.519	–0.425	–0.327
AER net capex allowance	11.66	11.84	10.70	11.64	11.55

Notes: Totals may not add due to rounding. The AER capex allowance includes $0.36 million for equity raising costs.

(a) This includes proposed equity raising costs.

17.3.4 Building block elements

17.3.4.1 Return on capital

The AER applied a nominal vanilla WACC of 9.76 per cent to ETSA Utilities' alternative control metering services building block consistent with its conclusions set out in the cost of capital chapter of this decision (section 11.5).

The AER determined ETSA Utilities' return on capital allowance for alternative control metering services as set out in table 17.13.

17.3.4.2 Return of capital

Consistent with its current regulatory control period standard life of 30 years and the RFM, ETSA Utilities adopted 14.7 years as the remaining life to be applied to its alternative control metering assets as at 30 June 2010. From 1 July 2010, ETSA Utilities proposed a standard life of 15 years for metering assets. The AER assessed this change to metering asset lives in the draft decision and found that the proposed standard lives reflect the economic life of these assets, consistent with clause 6.5.5(b)(1) of the NER.[927]

On the basis of the approved asset lives, opening RAB and forecast capex allowance the AER has determined ETSA Utilities regulatory depreciation allowance for alternative control metering services as set out in table 17.13.

17.3.4.3 Operating expenditure

ETSA Utilities' proposed forecast opex elements are set out in table 17.10.

Table 17.10: ETSA Utilities proposed opex ($million, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
Meter maintenance costs	2.39	2.49	2.59	2.69	2.80
Meter reading costs	3.68	3.76	3.84	3.95	4.07
Other costs	0.25	0.14	0.14	0.14	0.14
Meter operating expenditure	6.32	6.39	6.58	6.78	7.01
Debt raising costs (Standard & Poors)	0.05	0.05	0.05	0.05	0.05
Debt raising costs	0.04	0.05	0.05	0.05	0.05
Total meter operating expenditure	6.41	6.49	6.68	6.89	7.12

Source: ETSA Utilities *Revised regulatory proposal,* January 2010, RIN 65 – metering capital and opex expenditure; and Attachment K.2 alternative control service metering.

ETSA Utilities stated that its meter maintenance opex is derived as a proportion of its baseline network maintenance costs because its regulatory accounts do not separate

927 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 284.

maintenance costs into component parts. Therefore, ETSA Utilities apportioned network maintenance costs based on its management accounts for 2007 and 2008. ETSA Utilities showed that on average during those two years its metering component was 12.5 per cent of total network maintenance.[928] ETSA Utilities therefore transferred 12.5 per cent of maintenance costs from standard control services to alternative control services. ETSA Utilities stated that its metering maintenance costs was varied to take account of scope changes to facilitate delivery of a meter testing and inspection program consistent with new regulatory requirements. These scope changes were accepted in the draft decision.[929]

Meter reading costs are forecast by ETSA Utilities using its baseline 2007–08 meter reading costs to which customer growth and input cost escalators are applied. The AER notes these meter reading costs were part of ETSA Utilities' forecast customer services expenditure which was approved in the draft decision.[930]

ETSA Utilities' 'other costs' category relates to the expenditure associated with setting up and administering the new billing system to implement alternative control metering services. It provided initial correspondence with system developers that indicate ongoing discussions to develop its system changes and associated costs are occurring. These discussions suggest that the proposed annual costs associated with an additional employee and auditing (including the first year's increase to recover system changes) are reasonable.[931]

The AER considers that ETSA Utilities' forecast alternative control meter opex (excluding debt raising cost) is reasonable, subject to the application of real cost escalators consistent with its conclusions set out in appendix G of this decision. The AER's conclusion on ETSA Utilities forecast opex is set out in table 17.11.

Debt raising costs

ETSA Utilities' proposed debt raising costs are consistent with the draft decision debt raising costs benchmark of 0.091 per cent. The AER accepts ETSA Utilities' proposal to apply the benchmark debt raising costs derived for standard control services. Consistent with this decision, the AER has allowed debt raising costs benchmark of 0.091 per cent.

ETSA Utilities also proposed additional debt raising costs of $0.05 million per annum associated with the completion method (debt raising Standard & Poors). The AER reviewed the completion method and its conclusions are set out in Appendix J of this decision. Consistent with its conclusions the AER has not allowed these costs. The debt raising cost allowance for ETSA Utilities is set out in table 17.11

928 ETSA Utilities, response to information request AER.EU.RP.7, 23 February 2010, p. 7.
929 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 237.
930 AER, *Draft decision, SA draft distribution determination*, November 2009, p. 222.
931 ETSA Utilities, *Revised regulatory proposal*, January 2010, RIN 67 – unbundling of metering.

Table 17.11: AER conclusion on ETSA Utilities forecast opex allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15
ETSA Utilities controllable opex proposal	6.32	6.39	6.58	6.78	7.01
AER Adjustments to cost escalators	–0.02	–0.05	–0.08	–0.10	–0.12
AER controllable opex allowance	6.29	6.34	6.49	6.68	6.89
Debt raising costs Standard & Poors	0.0	0.0	0.0	0.0	0.0
Debt raising costs	0.04	0.05	0.05	0.05	0.05
AER's opex allowance	6.33	6.38	6.54	6.73	6.94

Exit charge – opex component

ETSA Utilities proposed a $60 ($, 2008–09) charge per exiting customer to recover the marginal back office cost of facilitating the transfer of the terminating customer in its systems. ETSA Utilities stated that this marginal back office cost was estimated on the basis of the per hour cost of a notional grade three employee. The tasks required to be undertaken include processing paper work associated with meter change over, running periodical manual reports tracking meter churn, generating billing, reconciliation and collecting exit fees, liaising with retailers and customers, and collating and processing regulatory and financial accounting adjustments.[932] The AER considers that the proposed exit charge – opex component based on identified tasks and per hour costs is a reasonable estimate of the marginal operating costs associated with a customer terminating the relevant alternative control metering service.

The AER notes that ETSA Utilities' has not provided an allowance to recover the forecast exit charge – opex component in its annual building block revenue requirements. The revenues from exit charges are only accounted as tariff income in the PTRM to derive the X factor. That is, ETSA Utilities has correctly accounted the exit charge revenue as forecast revenues in its WAPC but not included the same in its annual regulated revenue requirement.

17.3.4.4 Estimated cost of corporate income tax

ETSA Utilities stated that the opening tax asset base for metering assets was determined as set out in its regulatory proposal.[933] In the draft decision the AER concluded that the tax inputs to ETSA Utilities' PTRM and RFM are consistent with the relevant NER requirements.[934] ETSA Utilities has proposed an alternative control metering opening tax asset base of $58.77 million.[935]

Consistent with its revised regulatory proposal, ETSA Utilities adopted a gamma value of 0.50 rather than 0.65 as stated in the AER's *Statement of Regulatory Intent*

[932] ETSA Utilities, response to information request AER.EU.RP.7, 23 February 2010, p. 3.
[933] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D1, pp. 13–14.
[934] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 279.
[935] ETSA Utilities has deducted $0.34 million to account for negotiated metering services.

(SORI) and as provided for in the draft decision.[936] The AER determined that a gamma of 0.65 is appropriate for the reasons discussed in chapter 9 of this decision. The AER has applied a gamma of 0.65 to derive the estimated corporate income tax for ETSA Utilities' alternative control metering services. The allowance for corporate income tax is set out in table 17.12.

Table 17.12: AER conclusion on ETSA Utilities corporate income tax allowance ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
ETSA Utilities proposal	0.72	0.83	0.95	1.07	1.19
AER adjustments	–0.23	–0.28	–0.32	–0.36	–0.39
AER approved tax allowance	0.49	0.55	0.63	0.71	0.80

17.3.4.5 AER decision on the building block revenue requirement

Based on its building block components and using the PTRM, the AER determined an annual building block revenue requirement for ETSA Utilities alternative control metering services that increases from $18.45 million in 2010–11 to $26.57 million in 2014–15 ($ nominal). Table 17.13 sets out the annual building block calculations.

ETSA Utilities proposed the X factor for each year of the next regulatory control period be made equal to deliver a smooth price path within the next regulatory control period. The AER accepts this approach for the alternative control metering services X factor. After remodelling the annual revenue requirements and exit charges, the AER has determined ETSA Utilities' X factors for the next regulatory control period are –8.05 per cent in each regulatory year, as shown in table 17.13.

[936] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 284.

Table 17.13: AER decision on annual revenue requirement ($m, nominal)

	2010–11	2011–12	2012–13	2013–14	2014–15
Return on capital	7.87	8.73	9.56	10.21	10.92
Return of capital	3.60	4.37	5.20	6.04	6.99
Operating expenditure	6.49	6.71	7.05	7.44	7.86
Tax allowance	0.49	0.55	0.63	0.71	0.80
AER decision[a]	18.45	20.36	22.44	24.40	26.57
ETSA Utilities revised regulatory proposal[a]	18.97	21.00	23.27	25.37	27.67
AER adjustments	–0.52	–0.64	–0.83	–0.97	–1.00
ETSA Utilities proposed X factors (%)	–9.18	–9.18	–9.18	–9.18	–9.18
AER X factors (%)	–8.05	–8.05	–8.05	–8.05	–8.05

(a) Unsmoothed revenue requirement.

17.3.4.6 Indicative prices

The AER calculated indicative tariffs after applying the remodelled X factors which are set out in table 17.14. The AER notes these alternative control metering services prices are indicative only. However, the exit charges have been determined by the AER in this decision and ETSA Utilities confirmed that in the next regulatory control period the exit fee tariffs will remain constant in real terms.[937] ETSA Utilities' annual pricing proposal will be reviewed by the AER in accordance with Part I of chapter 6 of the NER.

Table 17.14: AER indicative prices for ETSA Utilities metering services ($2009–10)

Metering service	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Meter provision type 6 DCC ($/day)	0.0525	0.0567	0.0612	0.0662	0.0715	0.0773
Meter provision type 6 current transformer connected ($/day)	0.2325	0.2512	0.2714	0.2933	0.3169	0.3424
Meter provision Type 1–4 exceptional ($/day)	0.8151	0.8807	0.9516	1.0282	1.1110	1.2005
Meter service other meter provider customer ($/day)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Meter service exit fee type 6 (CTC) ($)	232	232	232	232	232	232
Meter service exit fee type 1–4 ($)	518	518	518	518	518	518

937 ETSA Utilities, response to information request AER.EU.RP.12, 17 March 2010, p. 6.

17.3.5 Compliance with the WAPC

The AER accepts ETSA Utilities' proposal that it will demonstrate compliance with the control mechanism by annually providing the proposed tariffs that correspond to the price terms contained in the WAPC approved by the AER.

ETSA Utilities intends to transition to the four individual DCC tariff components over the next regulatory control period from the single weighted average DCC tariff component applied in 2010–11. It stated that it will gradually transition customers to the individually calculated DCC tariff components from 2011–12.[938] It also stated that it expects to propose a smooth as possible transition over the four tariff adjustments associated with its pricing proposal during 2010 to 2014.[939]

ETSA Utilities' requested that the AER permit it to apply the reasonable estimates approach to tariff changes relating to alternative controls services similar to the approach stated in appendix E of the draft decision applicable to standard control services. The AER considers the adoption of the same approach relating to tariff changes to both standard control and alternative control services to be reasonable and will therefore apply the methodology set out in appendix E.3 of this decision in assessing the reasonableness of the quantity estimates provided by ETSA Utilities in relation to its WAPC for alternative control services. For this purpose, appendix E.3 should be read in the context of alternative control meter services.

ETSA Utilities is currently finalising its systems that correctly assign the proposed tariff components to individual NMIs and that historical audited data will only be available in time for the 2012–13 regulatory year pricing proposal.[940] In assessing reasonableness, in addition to the matters listed in appendix E.3, the AER will also take into consideration the fact that audited data will not be available until 2012–13.

17.4 AER conclusion

17.4.1 Weighted average price cap

The WAPC applicable to ETSA Utilities' alternative control metering services for the next regulatory control period is:

$$(1+CPI_t)\times(1-Xt)\geq\frac{\sum_{i=1}^{n}\sum_{j=1}^{m}p_t^{ij}\times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m}p_{t-1}^{ij}\times q_{t-2}^{ij}}$$

where ETSA Utilities has *n distribution tariffs*, which each have up to *m distribution tariff components*, and where:

regulatory year t is the regulatory year in respect of which the calculation is being made;

938 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D1, pp. 13–14.
939 ETSA Utilities, response to information request AER.EU.RP.12, 17 March 2010, p. 6.
940 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment D1, pp. 14.

regulatory year t–1 is the regulatory year immediately preceding regulatory year t;

regulatory year t–2 is the regulatory year immediately preceding regulatory year t–1;

p_t^{ij} is the proposed distribution tariff for component j of distribution tariff i in regulatory year t ;

p_{t-1}^{ij} is the distribution tariff being charged in regulatory year t–1 for component j of distribution tariff i;

q_{t-2}^{ij} is the quantity of component j of distribution tariff i that was delivered in regulatory year t–2;

CPI_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 to be determined using the building block approach.

ETSA Utilities is required to include proposed distribution tariff classes (n) and components (m) for both variable standard small customer metering services and the two exceptional case metering services.

17.4.2 Demonstration of compliance

ETSA Utilities must submit, as part of its annual pricing proposal to the AER proposed tariffs that correspond to the price terms contained within the WAPC equation approved by the AER in this decision.

17.5 AER decision

In accordance with clause 6.12.1(12) of the NER, the control mechanism for alternative control services provided by ETSA Utilities is a weighted average price cap. The applicable WAPC formula is set out in section 17.4.1 of this decision.

In accordance with clause 6.12.1(13) of the NER, ETSA Utilities must demonstrate compliance with the control mechanism for alternative control services by providing, as part of its annual pricing proposal, the proposed tariffs which correspond to the price terms contained in the WAPC equation.

Glossary

AASB	Australian Accounting Standards Board
ABS	Australian Bureau of Statistics
ACG	Allen Consulting Group
ADMD	After Diversity Maximum Demand
AGL	AGL Energy Ltd
AMI	Advanced Metering Infrastructure
ANZSIC	Australian and New Zealand Standard Industry Classifications
AON Global	AON Global Risk Consulting
ATO	Australian Tax Office
BBI	Babcock Brown Infrastructure
bppa	basis points per annum
CAM	cost allocation method
CAPM	capital asset pricing model
CBD	central business district
CCTV	closed circuit television
CEG	Competition Economists Group
CFC	Construction Forecasting Council
CGS	Commonwealth government securities
CPRS	carbon pollution reduction scheme
CRA	Charles River Associates
DBNGP	Dampier to Bunbury Natural Gas Pipeline (WA) Transmission Pty Ltd
DBP	Dampier to Bunbury pipeline
DEWHA	Department of the Environment, Water, Heritage and the Arts
DLC	direct load control
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DRP	debt risk premium
DUET	Diversified Utility and Energy Trust
DUOS	distribution use of system

EBA	enterprise bargaining agreement
EBSS	efficiency benefit sharing scheme
ECCSA	Energy Consumers Coalition of South Australia
ECM	efficiency carryover mechanism
EDC	*Electricity Distribution Code of South Australia*
EDPD	electricity distribution price determination
EGW	electricity, gas and water
EPO	Electricity Pricing Order
ESCOSA SORI	ESCOSA, *Statement of Regulatory Intent*, March 2007
EUAA	Energy Users Association of Australia
FBG	Fosters Brewing Group
FIG	Financial Investor Group
FMG	Fortescue Metals Group
gamma (γ)	assumed utilisation of imputation credits
GFC	global financial crisis
GSP	gross state product
Guideline 13	ESCOSA, *Application of chapter 3 of the electricity distribution code – Electricity industry guideline No. 13.*
GVA	gross value added
GWh	gigawatt hour
HDF	Hastings Diversified utilities Fund
IT	information technology
JWS	Johnson Winter & Slattery
KI joint parties	Kangaroo Island Council, Regional Development Australia Board (Adelaide Hills, Fleurieu and Kangaroo Island) and Tourism Kangaroo Island
KPMG	KPMG Econtech
kV	kilovolt, (one thousand volts)
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt hour
LME	London Metal Exchange
LPI	labour price index
MAIFI	momentary average interruption frequency index

MCE	Ministerial Council on Energy
MCE SCO	Ministerial Council on Energy Standing Committee of Officials
McGrathNicol	McGrathNicol Corporate Advisory – McGrathNicol is an independent advisory firm specialising in Corporate Advisory, Forensic, Transaction Services and Corporate Recovery.
MED	major event day
MEPS	minimum energy performance standards
MEU	Major Energy Users Group
MRP	market risk premium
MTN	medium term note
MVA	mega volt ampere
MW	mega watt, (one thousand kilowatts)
MWh	mega watt hour
NDSC	negotiated distribution service criteria
NECF	National Energy Customer Framework
NEO	national electricity objective
NERA	NERA Economic Consulting
NIEIR	National Institute of Economic and Industry Research
NMI	national meter identifier
NOC	network operations centre
NPV	net present value
NSP	network service provider
NTER	national tax equivalence regime
Origin	Origin Energy Retail Pty Limited
payout ratio	imputation credit payout ratio
PoE	probability of exceedence
PTRM	post–tax revenue model
PV	photovoltaic
Qld DNSPs	Energex and Ergon Energy
R&D	research and development
RAB	regulatory asset base
RBA	Reserve Bank of Australia

REC	renewable energy credit
REES	Residential Energy Efficiency Scheme
RFM	roll forward model
RIN	regulatory information notice
ROLR	retailer of last resort
SA Energy Minister	the South Australia Minister for Energy, the Honourable Patrick Conlon, MP
SACOSS	South Australian Council of Social Service
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.
STPIS	service target performance incentive scheme
TEC	Total Environment Centre
TFA	Toyota Finance Australia Ltd.
the WACC review	AER, *Electricity transmission and distribution network service providers–Review of the weighted average cost of capital (WACC) parameters*, May 2009.
theta (θ)	the utilisation rate of imputation credits
TNSP	transmission network service provider
TOU	time of use
Tribunal	Australian Competition Tribunal
TTEG	Trans Tasman Energy Group
TUOS	transmission use of system
UK	United Kingdom
UnitingCare	UnitingCare Australia
UPS	uninterruptable power supply
US	United States of America

VEDBs	Victorian electricity DNSPs
WACC	weighted average cost of capital
WAPC	weighted average price cap
Wilkenfeld	George Wilkenfeld and Associates

A. ETSA Utilities distribution services classification

This appendix sets out the AER's classification of ETSA Utilities distribution services for the next regulatory control period. Italicised terms are defined in the NER.

Direct control (standard control) services

A.1 Standard network services

a. All *network services* except:

   i. *network services* provided at the request of a *distribution network user*:

      1. with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the NER, the *Electricity Distribution Code*, or any other applicable regulatory instruments, or

      2. in excess of levels of service or plant ratings required to be provided by ETSA Utilities' assets, or

   ii. extension or augmentation of the *distribution network* associated with the provision of a new *connection point* or upgrading of the capability of a connection point to the extent that a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*, or

   iii. other *network services* that are classified as *negotiated distribution services* in sections B.7 to B.16 of this appendix B.

A.2 Standard connection services

a. All *connection services* except:

   i. *connection services* provided at the request of a *distribution network user*:

      1. with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the NER, the *Electricity Distribution Code*, or any other applicable regulatory instruments, or

      2. in excess of levels of service or plant ratings required to be provided by ETSA Utilities' assets, or

   ii. the provision of a new *connection point* or upgrading of the capability of a connection point to the extent that a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*, or

iii. other *connection services* that are classified as *negotiated distribution services* in sections B.7 to B.16 of this appendix B.

A.3 Fixed standard small customer metering services

a. The provision of *energy data services* in respect of meters meeting the requirements of a *metering installation* type 6 except the quarterly meter read service.

A.4 Unmetered metering services

a. The provision of metering services in respect of meters meeting the requirements of a *metering installation* type 7.

Direct control (alternative control) services

A.5 'Variable' 'standard' 'small' customer metering services

a. The provision of:

  i. meter provision services in respect of meters meeting the requirements of a *metering installation* type 6, and

  ii. quarterly meter read services in respect of meters meeting the requirements of a *metering installation* type 6.

b. For the purposes of this clause, meter provision services include, but are not necessarily limited to, any asset related and administrative costs associated with the provision, installation, maintenance, and replacement of the meter (including circumstances in which ETSA Utilities meter is replaced by that of another meter provider).

A.6 Exceptional large customer metering services

a. Meter provision services provided in respect of meters meeting the requirements of a *metering installation* type 1, *metering installation* type 2, *metering installation* type 3 or *metering installation* type 4 installed prior to 1 July 2000.

b. Meter provision services provided in accordance with the requirement of clause 27 of ETSA Utilities' distribution licence as in force at 30 June 2005.

c. For the purposes of this clause, meter provision services include, but are not necessarily limited to, any asset related and administrative costs associated with the provision, installation, maintenance, and replacement of the meter (including circumstances in which ETSA Utilities meter is replaced by that of another meter provider).

Negotiated distribution services

A.7 Non-standard network services

a. *Network services* provided at the request of a *distribution network user*:

i. with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the NER, the *Electricity Distribution Code*, or any other applicable regulatory instruments, or

ii. in excess of levels of service or plant ratings required to be provided by ETSA Utilities' assets

A.8 Non-standard connection services

a. *Connection services* provided at the request of a *distribution network user*:

   i. with higher quality or reliability standards, or lower quality or reliability standards (where permissible), than are required by the NER, the *Electricity Distribution Code*, or any other applicable regulatory instruments, or

   ii. in excess of levels of service or plant ratings required to be provided by ETSA Utilities' assets.

A.9 New and upgraded connection point services

a. Extension or augmentation of the *distribution network* associated with the provision of a new *connection point* or upgrading of the capability of a *connection point* to the extent that a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code.*

b. The provision of a new *connection point* or upgrading of the capability of a *connection point* to the extent that a *distribution network user* is required to make a financial contribution in accordance with the *Electricity Distribution Code*.

c. Responding to an enquiry in relation to the provision of a new *connection point* referred to in paragraph A.9(a) or (b).

d. The provision of technical specifications in relation to the upgrading of the capability of a *connection point* referred to in paragraph A.9(a) or (b).

e. Preliminary communications with a customer, being an existing or potential *distribution network user* where more than 6 hours work is required.

A.10 Non-standard small customer metering services

a. In relation to 'small' *distribution network users* (at present, those consuming less than 160MWh per annum), the provision of metering services:

   i. at all first tier *connection points* and second tier *connection points* where a meter meeting the requirements of a *metering installation* type 1, *metering installation* type 2, *metering installation* type 3, *metering installation* type 4 or *metering installation* type 5 is or is to be installed, or

ii. in respect of meters meeting the requirements of a *metering installation* type 6 and *metering installation* type 7 containing a meter different to the type of meter ETSA Utilities would ordinarily install (including prepayment meter systems), which is installed at the request of a retailer or a *distribution network user.*

b. In relation to energy data services, the provision of special meter readings and associated services.

A.11 Large customer metering services

a. The provision of *metering services* to ‘large’ customers (at present, those consuming more than 160MWh per annum), except for:

   i. meter provision services provided in respect of meters meeting the requirements of a *metering installation* type 1, *metering installation* type 2, *metering installation* type 3 or *metering installation* type 4 installed prior to 1 July 2000, or

   ii. meter provision services provided in accordance with the requirement of clause 27 of ETSA Utilities’ distribution licence as in force at 30 June 2005.

A.12 Public lighting services

a. Street lighting use of system services

   i. The provision of public lighting assets, and the operation and maintenance of those assets where ETSA Utilities retains ownership of the assets.

b. Customer lighting equipment rate services

   i. The replacement of failed lamps in customer-owned streetlights where the customer retains ownership of the assets and is responsible for all other maintenance.

c. Energy only services

   i. The maintenance of a database relating to street lights, and recording and informing customers of streetlight faults reported to ETSA Utilities where customers retain ownership of the assets and are responsible for all maintenance (including replacement of failed lamps).

A.13 Stand-by and temporary supply services

a. The following services associated with stand-by and temporary supply:

   i. provision of electric plant or stand-by generator for the specific purpose of enabling the provision of top-up or stand-by supplies or sales of electricity

   ii. provision of *network services* for a *connection point* where a *distribution network user* operates parallel generation requiring a stand-by supply

   iii. provision of temporary supplies, and

iv. provision of reserve (duplicate) supply.

A.14 Asset relocation, temporary disconnection and temporary line insulation services

a. Moving mains, services or meters forming part of the *distribution system*, providing temporary disconnection, or temporary line insulation to accommodate extensions, re-design or re-development of any premises or otherwise as requested by a *distribution network user*.

b. Provision of network access management services for a distribution network user or external party.

A.15 Embedded generation services

a. Services and system augmentation or extension required to receive energy from an embedded generator and meet the requirements of the NER.

b. Services associated with non-compliance of the embedded generator with the *connection agreement*, including but not limited to reactive power, power factor, harmonics, voltage dips and test supply arrangements.

A.16 Other Services

a. The following services provided in connection with the *Electricity Distribution Code*, *Electricity Metering Code* or the NER:

   i. application for an account or new supply

   ii. provision of a copy of the *Electricity Distribution Code* or the *Electricity Metering Code*

   iii. provision of old billing data

   iv. meter testing at the request of a distribution network user

   v. after-hours reconnection

   vi. reconnection due to a distribution network users' fault, and

   vii. disconnection services provided to a retailer, or a distribution network user.

b. Provision of reactive power and energy to a *connection point* or receipt of reactive power and energy from a distribution *connection point.*

c. Investigation and testing services.

d. Asset location and identification services.

e. The transportation of electricity not consumed in the *distribution system.*

f. The transportation of electricity to *distribution network users* connected to the distribution system adjacent to the transmission system.

g. Repair of equipment damaged by a *distribution network user* or a third party.

h. Provision of:

   i. high load escorts

   ii. measurement devices

   iii. protection systems, and

   iv. pole attachments, ducts or conduits (excluding for the provision of telecommunications services).

i. Costs incurred by ETSA Utilities as a result of a customer not complying with ETSA Utilities’ standard connection and supply contract or other obligation.

j. Additional costs incurred by ETSA Utilities where service provision could not be undertaken and/or completed as planned due to the actions, or inaction, of a customer or their agent.

k. Provision of a television or radio interference investigation where it is determined that the distribution system is not the cause of the interference.

l. Provision of a supply interruption investigation where it is determined that the distribution system was not the cause of the interruption.

m. Provision of information to *distribution network users* or third parties not related to connection enquiries.

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 ETSA Utilities prior to 1 July 2010, and who continues to be a customer of ETSA Utilities as at 1 July 2010, will be taken to be "assigned" to the tariff class which ETSA Utilities 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, ETSA Utilities becomes aware that a person will become a customer, then ETSA Utilities 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, ETSA Utilities 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[941]
   (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, ETSA Utilities, when assigning or reassigning a customer to a tariff class, must ensure the following:
   (a) customers with similar connection and usage profiles are treated equally
   (b) 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 ETSA Utilities 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 materially similar load or connection characteristics as other customers on the

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

customer’s existing tariff class, then it may reassign that customer to another tariff class.

Objections to proposed assignments and reassignments

6. ETSA Utilities 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 ETSA Utilities 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 ETSA Utilities internal procedures for reviewing objections or the link to where such information is available on ETSA Utilities’ website

   b. that if the objection is not resolved to the satisfaction of the customer under ETSA Utilities’ 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, ETSA Utilities 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 ETSA Utilities about the proposed assignment or reassignment, ETSA Utilities 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 ETSA Utilities 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, ETSA Utilities 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 ETSA Utilities 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 ETSA Utilities.

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 schedules 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

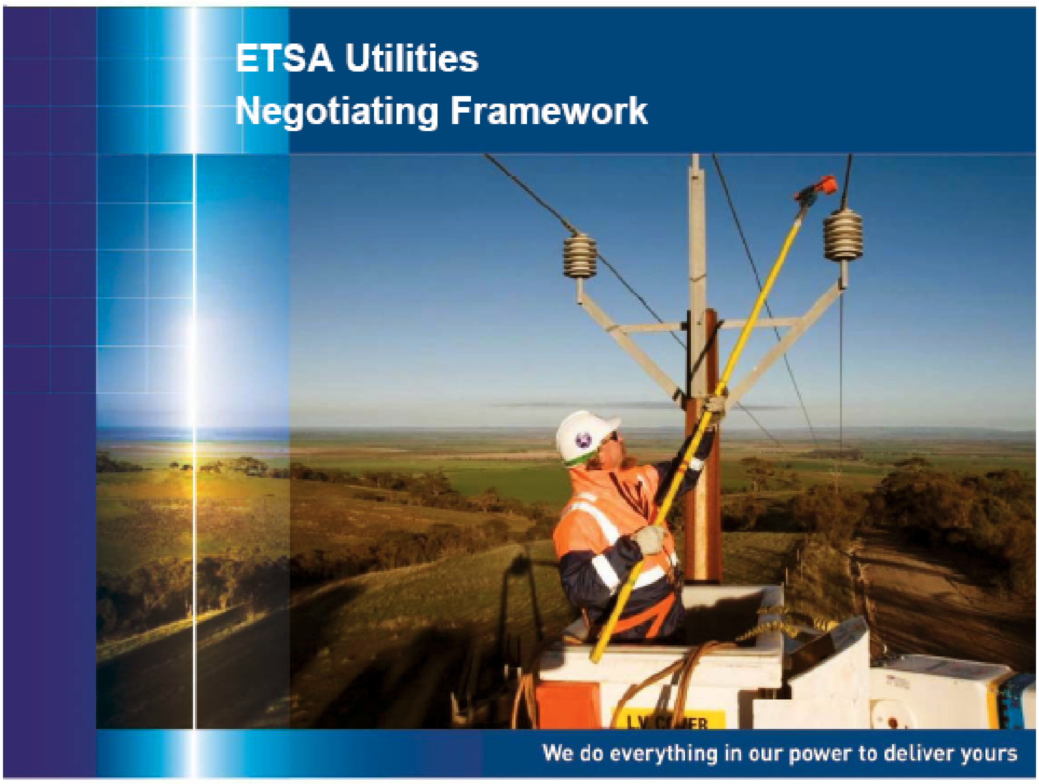
Access Charges

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. ETSA Utilities Negotiating framework

The AER has amended ETSA Utilities' revised negotiating framework in accordance with the requirements set out in section 3.5 of this decision. The amended negotiating framework is included in this appendix.

ETSA Utilities



January 2010

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2010 05 04 – ETSA Utilities revised negotiation framework

Preamble

A. Chapter 6 of the National Electricity Rules (the Rules) requires that:

a) a Distribution Network Service Provider prepare a document setting out the procedure to be followed during negotiations between it and any person (a *Service Applicant*) who wishes to receive a *Negotiated Distribution Service*, as to the terms and conditions of access for the provision of the service (clause 6.7.5(a));

b) The negotiating framework comply with and be consistent with the applicable requirements of the Distribution Network Service Provider's distribution determination (clause 6.7.5(b)); and

c) The negotiating framework comply with and be consistent with the applicable requirements of clause 6.7.5(c), which sets out the minimum requirements for a negotiating framework.

B. This document has been prepared in fulfilment of *ETSA Utilities*' obligations under clause 6.7.5(a) of the Rules to establish a negotiating framework.

C. This document applies to *ETSA Utilities* and any *Service Applicant* who applies to receive a *Negotiated Distribution Service*.

D. *ETSA Utilities* provides a number of *Negotiated Distribution Services* which fall into one of two classifications:

a) ***Individually Negotiated Services***, which are services for which an individual quotation, terms and conditions of supply and *charges* will be prepared and for which no indicative price is published by *ETSA Utilities* in its *Indicative Price List*; and

b) ***Indicative Price List Services***, which are services for which an indicative price is given in the *Indicative Price List* published annually by *ETSA Utilities*.

E. This document specifies the *Negotiated Distribution Service Criteria*, information disclosure process, and timetable which will apply to each classification of *Negotiated Distribution Services*, noting that, in relation to the determination of access disputes, Part 10 of the National Electricity Law (NEL) and Part L of the National Electricity Rules (NER) are applicable.

F. This document also specifies the process for the annual publication of the indicative prices and what information is disclosed for *Indicative Price List Services*.

G. The structure of *ETSA Utilities'* Negotiating Framework is illustrated in Figure 1.

H. Various provisions of the NEL and the Rules are relevant to the provision of negotiated distribution services by *ETSA Utilities*. This negotiating framework is subject to the provisions of the NEL and the Rules, which may include provisions that are specific to South Australia in Chapter 9 of the Rules.

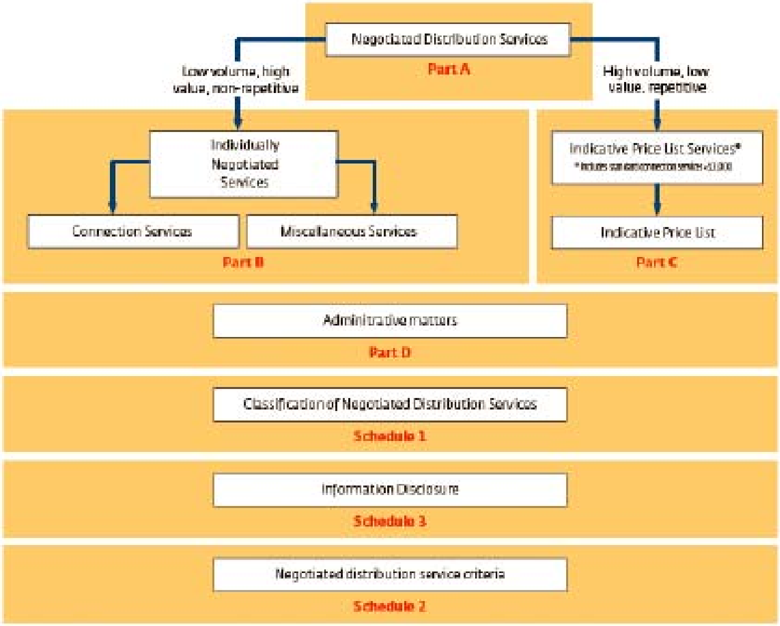

Figure 1 - Structure of ETSA Utilities' Negotiating Framework

ETSA Utilities' Negotiating Framework

1. Structure of Negotiating Framework

1.1 Part A of this Negotiating Framework sets out arrangements for the classification of *Negotiated Distribution Services* and the commercial obligations applicable to *ETSA Utilities* and *Service Applicants*.

1.2 Part B contains the provisions for *Individually Negotiated Services*.

1.3 Part C contains the provisions for *Indicative Price List Services*.

1.4 Part D contains administrative provisions which apply to both classifications of *Negotiated Distribution Services*.

Part A Provisions applicable to all Negotiated Distribution Services

2. Application of Negotiating Framework

2.1 This Negotiating Framework applies to *ETSA Utilities* and:

a) each *Service Applicant* who has made an application in writing to *ETSA Utilities* for the provision of a *Negotiated Distribution Service*; and

b) each *Service Applicant* or prospective *Service Applicant* participating in consultation on the provision of a *Negotiated Distribution Service*.

2.2 *ETSA Utilities* and any *Service Applicant* who wishes to receive a *Negotiated Distribution Service* from *ETSA Utilities* must comply with the requirements of this Negotiating Framework.

2.3 The requirements set out in this Negotiating Framework are additional to any requirements or obligations contained in Rules 5.3 and 5.5. In the event of any inconsistency between this Negotiating Framework and any other requirements in the Rules, the requirements of the Rules will prevail.

2.4 Nothing in this Negotiating Framework or in the Rules will be taken as imposing an obligation on *ETSA Utilities* to provide any service to the *Service Applicant*.

3. Classification of Negotiated Distribution Services

3.1 The *Negotiated Distribution Services* provided by *ETSA Utilities* are divided into two classifications:

a) ***Individually Negotiated Services*** which are services for which an individual quotation, terms and conditions of supply and *charges* will be prepared and for which no indicative price is published by *ETSA Utilities* in its *Indicative Price List*. Part B of this Negotiating Framework contains the provisions for *Individually Negotiated Services*; and

b) ***Indicative Price List Services***, which are services for which an indicative price is given in the *Indicative Price List* published annually by *ETSA Utilities*. Part C of this Negotiating Framework contains the provisions for *Indicative Price List Services*.

3.2 *ETSA Utilities* will determine the classification of each of its *Negotiated Distribution Services*.

3.3 Schedule 1 of this Negotiating Framework indicates the initial classifications applying to each of the *Negotiated Distribution Services* provided by *ETSA Utilities*. For a number of services, the service may be either a *Individually Negotiated Service* or a *Indicative Price List Service* depending on whether the service is repetitive or non-repetitive. . Generally, services that are repetitive in nature and occur in relatively high volumes will be detailed in the *Indicative Price List*, whereas services that are non-repetitive will not appear in the *Indicative Price List*.

3.4 *ETSA Utilities* may re-classify its *Negotiated Distribution Services* on an annual basis. Any such re-classification, and the basis for the re-classification, will be explained in *ETSA Utilities'* annual *Indicative Price List* publication as referred to in clause 20 and Schedule 3.

4. Obligation to negotiate in good faith

4.1 *ETSA Utilities* and the *Service Applicant* must negotiate in good faith the terms and conditions for the provision by *ETSA Utilities* of the *Negotiated Distribution Service* sought by the *Service Applicant*.

5. Provision of Commercial Information by Service Applicant

5.1 *ETSA Utilities* may give notice to the *Service Applicant* requesting *Commercial Information* held by the *Service Applicant* that is reasonably required by *ETSA Utilities* to enable it to engage in effective negotiations with the *Service Applicant* in relation to the application

Confidentiality Requirements

5.2 For the purposes of this clause 5, *Commercial Information* does not include:

a) confidential information provided to the *Service Applicant* by another person; or

b) information that the *Service Applicant* is prohibited, by law, from disclosing to *ETSA Utilities*.

5.3 *Commercial Information* may be provided by the *Service Applicant* subject to reasonable conditions, which may include a condition that *ETSA Utilities* not disclose the *Commercial Information* to any other person unless the *Service Applicant* consents in writing to the disclosure or it is otherwise compelled to do so by law.

5.4 In respect of any confidential information that may be provided by the *Service Applicant* to *ETSA Utilities*, the *Service Applicant* may require *ETSA Utilities* to enter into a confidentiality agreement in respect of this information, on terms reasonably acceptable to both parties, with the *Service Applicant*.

5.5 A consent to disclose information provided by the *Service Applicant* in accordance with clause 5.3 may be subject to the condition that the person to whom *ETSA Utilities* discloses the *Commercial Information* is also subject to a condition that the person does not provide any part of that commercial information to any other person without the consent of the *Service Applicant*.

6. Provision of Commercial Information by ETSA Utilities

6.1 *ETSA Utilities* must provide the following *Commercial Information* to the *Service Applicant*, upon written request, where such information is reasonably required by the *Service Applicant* to enable them to engage in effective negotiations with *ETSA Utilities* for the provision of a *Negotiated Distribution Service*[1]:

a) a description of the nature of the *Negotiated Distribution Service* including what *ETSA Utilities* would provide to the *Service Applicant* as part of that service;

b) the *charges* applicable for providing the service based on the information that is available to *ETSA Utilities;*

c) the terms and conditions upon which *ETSA Utilities* would provide the *Negotiated Distribution Service* to the *Service Applicant*;

d) the reasonable *costs* and/or the increase or decrease in *costs* (as appropriate) in providing the *Negotiated Distribution Service* to the *Service Applicant*;

e) a demonstration to the *Service Applicant* that the *charges* for providing the *Negotiated Distribution Service* are in compliance with *ETSA Utilities' Negotiating Distribution Service Criteria (NDSC) and CAM (Cost Allocation Methodology)*;

f) information referred to under Clause 12 in relation to the assessment and review of the basis of *charges*; and

g) any other information that the *Service Applicant* reasonably requires to enable effective negotiation on the price and the terms and conditions associated with the provision of the *Negotiated Distribution Service*.

Confidentiality Requirements

6.2 For the purposes of clause 6.1, *Commercial Information* does not include:

a) confidential information provided to *ETSA Utilities* by another person; or

b) information that *ETSA Utilities* is prohibited, by law, from disclosing to the *Service Applicant*.

6.3 *ETSA Utilities* may provide the *Commercial Information* in accordance with clause 6.1 subject to relevant conditions including the condition that the *Service Applicant* must not disclose the *Commercial Information* to any other person unless *ETSA Utilities* consents in writing to the disclosure. *ETSA Utilities* may require the *Service Applicant* to enter into a confidentiality agreement with *ETSA Utilities*, on terms reasonably acceptable to both parties, in respect of *Commercial Information* provided to the *Service Applicant*.

6.4 A consent provided to a *Service Applicant* in accordance with clause 6.3 may be subject to the condition that a person to whom the *Service Applicant* discloses the *Commercial Information* must enter into a separate confidentiality agreement with *ETSA Utilities*.

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1 Noting that in the case of *Indicative Price List Services*, in the first instance a *Service Applicant* should refer to the information provided in the annual *Indicative Price List* publication, as required under clause 20.

7. Negotiating Distribution Service Criteria

7.1 In developing its *prices* for *Negotiated Distribution Services*, *ETSA Utilities* will comply with:

7.1.1 the *AER* approved *Negotiating Distribution Service Criteria* which are reproduced in Schedule 2; and

7.1.2 any local jurisdictional requirements.

Part B Provisions applicable to Individually Negotiated Services

8. Types of Individually Negotiated Services

8.1 Two different types of *Individually Negotiated Services* are provided by *ETSA Utilities*:

a) ***Connection Services***, which are services associated with the establishment of a new connection to the network, or the modification of an existing connection, and include any associated extension or augmentation of the network[2]; and

b) ***Miscellaneous Services***, which are all other *Individually Negotiated Services*.

9. Process and Timeframe for providing Connection Services

9.1 Clause 9.2 and Table 1 set out the timeframe for commencing, progressing and finalising negotiations in relation to applications for Connection Services. The timeframe set out in clause 9.2 may be suspended in accordance with clause 13.

9.2 Timeframes:

a) The specified time for commencing, progressing and finalising negotiations with a *Service Applicant* is as set out in Table 2.

b) *ETSA Utilities* and the *Service Applicant* will use reasonable endeavours to adhere to the time periods specified in Table 2 and may, by agreement, extend any such time period.

c) The preliminary program finalised under event "C" in Table 2 may be modified from time to time by agreement between the parties, where such agreement must not be unreasonably withheld. Any such amendment to the preliminary program will be taken to be a reasonable period of time for commencing, progressing and finalising negotiations with a *Service Applicant* for the provision of the *Negotiated Distribution Service*.

10. Contestability of parts of Connection Services

10.1 The *Service Applicant* can request that *ETSA Utilities* prepare specifications for *connection assets* and the *extension* associated with the supply of the connection services. Once the customer has provided the required information and has paid the specification preparation fee, then *ETSA Utilities* will provide the specification within:

a) a reasonable time as agreed with the customer where the specifications are complex, such time to be no more than 20 *Business Days;* and

b) *10 Business Days* in all other cases.

10.2 The *Service Applicant* can call for tenders for the design and construction of the connection assets and the extension, based on the specifications prepared under 10.1;

10.3 If the *Service Applicant* advises ETSA Utilities that they have selected a successful tenderer then ETSA Utilities will liaise with the *Service Applicant* and the successful tenderer to have the *connection assets* and extension assets connected to the distribution network once these assets have been completed to the satisfaction of ETSA Utilities.

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[2] Noting that, as required under Chapter 1 of the Electricity Distribution Code, standard connections and alterations will continue to be provided free of charge. In addition, certain low value, repetitive *Connection Services* may attract a charge, but are provided as *Indicative Price List Services*.

10.4 Nothing in this clause 10 obliges *ETSA Utilities to* accept the design and construction of the *connection assets* or the *extension* by a successful tenderer if *ETSA Utilities*, acting reasonably, forms the view that:

a) the successful tenderer does not have the requisite skill and competence to undertake the design and construction of the works in accordance with the specifications; and

b) the proposed design and construction do not meet the specification prepared under clause 10.1.

Table 1 - Timetable for *Connection Services*

Event		Indicative timeframe[3]	
		Normal	Complex
A.	Receipt of an application for a *Negotiated Distribution Service*. The application must be made by completing an Application Form in accordance with *ETSA Utilities'* publications or as otherwise agreed with *ETSA Utilities*. The application must include all information required by ETSA Utilities to make an offer and the *Service Applicant* must pay the application fee where requested.	X	X
B.	Parties discuss a preliminary negotiation programme with milestones that represent a reasonable period of time for commencing, progressing and finalising negotiations.	X + 5 *Business Days*	X + 10 *Business Days*
C.	Parties finalise negotiation programme, which may include, without limitation, milestones relating to: • the request and provision of *Commercial Information* by *ETSA Utilities* and the *Service Applicant* in relation to clauses 5 and 6; and • notification and consultation with any affected distribution network users in relation to clause 12.	X + 15 *Business Days*	X + 25 *Business Days*
D.	*ETSA Utilities* provides the *Service Applicant* with an offer for the *Negotiated Distribution Service*.	X + 20 *Business Days*	X + 35 *Business Days*
E.	Parties finalise negotiations.	X + 35 *Business Days*	X + 60 *Business Days*

11. Timeframe for progressing and finalising negotiations for Miscellaneous Services

11.1 Clause 11.2 and Table 2 set out the timeframe for commencing, progressing and finalising negotiations in relation to applications for *Miscellaneous Services*. The timeframe set out in clause 11.2 may be suspended in accordance with clause 14.

11.2 Timeframes:

a) The specified time for commencing, progressing and finalising negotiations with a *Service Applicant* is as set out in Table 2.

b) *ETSA Utilities* and the *Service Applicant* will use reasonable endeavours to adhere to the time periods specified in Table 2 and may, by agreement, extend any such time period.

c) The preliminary program finalised under event "C" in Table 2 may be modified from time to time by agreement between the parties, where such agreement must not

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[3] 'X' being the date that the service application is received.

be unreasonably withheld. Any such amendment to the preliminary program will be taken to be a reasonable period of time for commencing, progressing and finalising negotiations with a *Service Applicant* for the provision of the *Negotiated Distribution Service*.

Table 2 – Timetable for *Miscellaneous Services*

Event		Indicative timeframe[4]
A.	Receipt of an application for a *Negotiated Distribution Service*. The application must be made by completing an Application Form in accordance with *ETSA Utilities'* publications or as otherwise agreed with *ETSA Utilities*. The application must include all information required by ETSA Utilities to make an offer and the *Service Applicant* must pay the application fee where requested.	X
B.	Parties discuss a preliminary negotiation programme with milestones that represent a reasonable period of time for commencing, progressing and finalising negotiations.	X + 15 *Business Days*
C.	Parties finalise negotiation programme, which may include, without limitation, milestones relating to: • the request and provision of *Commercial Information* by *ETSA Utilities* and the *Service Applicant* in relation to clauses 5 and 6; • notification and consultation with any affected distribution network users in relation to clause 13; • the *Miscellaneous Distribution Service* being specified by the *Service Applicant;* and • the notification by *ETSA Utilities* of its *charges* related to processing the application and the payment of those *charges* by the *Service Applicant* as per clause 16.	X + 30 *Business Days*
D.	Parties progress negotiations and the *Service Applicant* specifies to *ETSA Utilities* the exact *Miscellaneous Distribution Service* which is required to be provided.	X + 40 *Business Days*
E.	Parties finalise negotiations.	X + 60 *Business Days*

12. Assessment and Review of Charges and Basis of Charges

12.1 *ETSA Utilities* will annually assess and review proposed *charges* for the *Connection Services* and *Miscellaneous Service* and the basis upon which those *charges* are made.

12.2 *ETSA Utilities* must make information on the assessment and review available to the *Service Applicant* in accordance with clause 6.

13. Determination of impact on other distribution network users and consultation with affected distribution network users

13.1 *ETSA Utilities* will determine the potential impact on distribution network users, other than the *Service Applicant*, of the provision of each *Negotiated Distribution Service*.

13.2 *ETSA Utilities* must notify and consult with any affected distribution network users and take reasonable steps to ensure that the provision of the *Negotiated Distribution Service* does not result in non-compliance with obligations to other distribution network users under the Rules.

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[4] 'X' being the date that the service application is received.

14. Suspension of Timeframe for Provision of a Negotiated Distribution Service

14.1 The timeframes for negotiation of provision of an *Individually Negotiated Service* in Table 1 and Table 2, or the timeframes that have been otherwise agreed between the parties, are suspended if:

a) a dispute in relation to the *Individually Negotiated Service* has been notified to the AER under Part 10 of the NEL, such suspension being from the date of notification of that dispute to the AER until the earlier of:

(i) the withdrawal of the dispute under section 126 of the NEL;

(ii) the termination of the dispute by the AER under section 131 or 132 of the NEL; or

(iii) determination of the dispute by the AER under section 128 of the NEL;

b) within 10 *Business Days* or as otherwise agreed between the parties[5] of *ETSA Utilities* requesting additional *Commercial Information* from the *Service Applicant* pursuant to clause 5, the *Service Applicant* has not supplied that *Commercial Information*;

c) without limiting clauses 14.1 a) or 14.1 b), the *Service Applicant* does not promptly conform with any of its obligations as required by this Negotiating Framework or as otherwise agreed between the parties;

d) *ETSA Utilities* has been required to notify and consult with any affected distribution network users under clause 13. Under these circumstances, the timeframes will be suspended from the date of notification to the affected distribution network users until the end of the time limit specified by *ETSA Utilities* for any affected distribution network users, or the receipt of such information from the affected distribution network users whichever is the later regarding the provision of the *Negotiated Distribution Service*;

e) The Service Applicant has not paid the application fee by the due date, with the suspension ceasing once the application fee is paid.

14.2 Each party will notify the other party if it considers that the timeframe has been suspended, within 5 *Business Days* of the relevant suspension event occurring.

Note: an application is not terminated by a suspension, unless a termination notice is issued under clause 17.

15. Dispute Resolution

15.1 Where negotiations with the *Service Applicant* fail to agree on the price and/or the terms and conditions of the service, it will be referred to the AER's dispute resolution processes in accordance with Part 10 of the NEL and Part L of the Rules, as applicable.

16. Payment of ETSA Utilities' application fee

16.1 *ETSA Utilities* may request from the *Service Applicant* an application fee relating to ETSA Utilities' reasonable direct expenses associated with processing the *Service Applicant's* application for the service.

16.2 The *Service Applicant* must pay the application fee within 10 business of receipt of the request, for *ETSA Utilities* to process the application and commence negotiations.

[5] If no agreement then 10 business days is the time period.

17. Termination of Negotiations

17.1 The *Service Applicant* may elect not to continue with its application for a *Negotiated Distribution Service* and may terminate the negotiations by giving *ETSA Utilities* written notice of its decision to do so.

17.2 *ETSA Utilities* may terminate a negotiation under this framework by giving the *Service Applicant* written notice of its decision to do so where:

a) *ETSA Utilities* believes on reasonable grounds that the *Service Applicant* is not conducting the negotiation under this Negotiating Framework in good faith;

b) the *Service Applicant* consistently fails to comply with the requirements of the Negotiating Framework;

c) the *Service Applicant* fails to comply with an obligation in this Negotiating Framework to undertake or complete an action within a specified or agreed timeframe, and does not complete the relevant action within 20 *Business Days* of a written request from *ETSA Utilities*;

d) the *Service Applicant* fails to make required payments in relation to the negotiation or provision of the service; or

e) an act of *Solvency Default* occurs in relation to the *Service Applicant*.

Part C Provisions applicable to Indicative Price List Services

18. Process to establish the Indicative Price List and Information Disclosure requirements for Indicative Price List Services

18.1 *ETSA Utilities* will utilise the following process to establish the indicative pricing and *Information Disclosure* for its *Indicative Price List Services*:

a) *ETSA Utilities* will submit this Negotiating Framework incorporating the *Information Disclosure* requirements to the AER with its Regulatory Proposal, for the approval of the AER;

b) *ETSA Utilities* will publish the approved Negotiating Framework, incorporating the *Negotiating Distribution Service Criteria* and *Information Disclosure* requirements;

c) *ETSA Utilities* will publish its *Indicative Price List* in accordance with clause 20; and

d) the dispute provisions which apply to *ETSA Utilities* and *Service Applicants* or prospective *Service Applicants* are set out in clause 24.

19. Information Disclosure

19.1 *ETSA Utilities* will comply with the *Information Disclosure* requirements detailed in Schedule 3.

20. Publication of Indicative Price List and information concerning Indicative Price List Services

20.1 *ETSA Utilities* will publish the *Indicative Price List* for its *Indicative Price List Services* to apply from 1st July of each year by 1st June of that year.

20.2 Such publication will incorporate the *Commercial information* concerning *ETSA Utilities' Indicative Price List Services* as described in the *Information Disclosure* requirements detailed in Schedule 3.

21. Timeframe for progressing and finalising negotiations for Indicative Price List Services

21.1 Clause 21.2 and Table 3 set out the timeframe for commencing, progressing and finalising negotiations in relation to applications for *Indicative Price List Services*. The timeframe set out in clause 21.2 may be suspended in accordance with clause 14.

21.2 Timeframes:

a) The specified time for commencing, progressing and finalising negotiations with a *Service Applicant* is as set out in Table 3.

b) *ETSA Utilities* and the *Service Applicant* will use reasonable endeavours to adhere to the time periods specified in Table 3 and may, by agreement, extend any such time period.

Table 3 - Timetable for Indicative Price List Services

Event		Indicative timeframe[6]
A.	Receipt of an application for a *Negotiated Distribution Service*. The application must be made by completing an Application Form in accordance with *ETSA Utilities'* publications or as otherwise agreed with *ETSA Utilities*. The application must include all information reasonably required by ETSA Utilities to make an offer and the *Service Applicant* must pay the application fee where requested..	X
B.	*ETSA Utilities* provides offer[7] for the *Negotiated Distribution Service*, including the terms and conditions	X + 5 *Business Days*
C.	*Service Applicant* advises that they wish to negotiate on the price and/or terms & conditions of the offer. Parties finalise negotiation programme, which may include, without limitation, milestones relating to: • the request and provision of *Commercial Information* by *ETSA Utilities* and the *Service Applicant* in relation to clauses 5 and 6; • notification and consultation with any affected distribution network users in relation to clause 23; and • The notification by *ETSA Utilities* of its *charges* related to processing the application and the payment of those *charges* by the *Service Applicant* as per clause 25.	X + 20 *Business Days*
D.	ETSA Utilities provides the *Service Applicant* with an offer based on the negotiations for the *Negotiated Distribution Service*	X + 25 *Business Days*
E.	Parties finalise negotiations.	X + 30 *Business Days*

22. Assessment and Review of Charges and Basis of Charges

22.1 *ETSA Utilities* will annually assess and review proposed *charges* for *Indicative Price List* Services and the basis upon which those *charges* are made.

22.2 *ETSA Utilities* must make information on the assessment and review available to the *Service Applicant* in accordance with clause 6.

23. Determination of impact on other distribution network users and consultation with affected distribution network users

23.1 *ETSA Utilities* will determine the potential impact on distribution network users, other than the *Service Applicant*, of the provision of each *Negotiated Distribution Service*.

23.2 *ETSA Utilities* must notify and consult with any affected distribution network users and take reasonable steps to ensure that the provision of the *Negotiated Distribution Service* does not result in non-compliance with obligations to other distribution network users under the Rules.

6 'X' being the date that the service application is received.

7 ETSA Utilities will provide the price for the Negotiated Distribution Services using the indicative price or methodology published in the *Indicative Price List*.

24. Dispute Resolution

24.1 Where negotiations with the *Service Applicant* fail to agree on the price and/or the terms and conditions of the service, the dispute may be referred to the AER's dispute resolution processes in accordance with Part 10 of the NEL and Part L of the Rules, as applicable.

25. Payment of ETSA Utilities' application fee

25.1 *ETSA Utilities* may request from the *Service Applicant* an application fee relating to ETSA Utilities' reasonable direct expenses associated with processing the *Service Applicant's* application for the service.

25.2 The *Service Applicant* must pay the application fee within 10 business of receipt of the request, for *ETSA Utilities* to process the application and commence negotiations.

Part D Administrative Provisions

26. Publication of Results of negotiations on website

26.1 *ETSA Utilities* will publish the following matters on its website:

a) a quarterly summary of the *Individually negotiated services* provided to *Service Applicants* and the total value of those services; and

b) a quarterly summary of the types and numbers of *Indicative Price List Services* provided to *Service Applicants*.

27. Giving notices

27.1 A notice, consent, information, application or request that must or may be given or made to a party under this document is only given or made if it is in writing and delivered or posted to that party at its address set out below.

Parties to agreement

27.2 If a party gives the other party 3 *Business Days* notice of a change of its address, a notice, consent, information, application or request is only given or made by that other party if it is delivered, posted or electronically transmitted to the latest address.

ETSA Utilities

1 Anzac Highway, Keswick, South Australia 5035

Postal address: GPO Box 77, Adelaide, South Australia 5001

e-mail: customerrelations@etsautilities.com.au

Service Applicant

Name: *Service Applicant*

Address: The nominated address of the *Service Applicant* provided in writing to *ETSA Utilities* as part of the application.

Time notice is given

27.3 A notice, consent, information, application or request is to be treated as given or made at the following time:

a) if it is handed to the *Service Applicant*, on the day that this occurs;

b) if it is delivered, when it is left at the relevant address;

c) if it is sent by post, 2 *Business Days* after it is posted;

d) if sent by facsimile transmission, on the day the transmission is sent, but only if the sender has a confirmation report specifying a facsimile number of the recipient, the number of pages sent and the date of transmission; or

e) if sent by e-mail, on the day the e-mail is sent, provided that a confirmation that the e-mail was received by the recipient is received by the sender.

27.4 If a notice, consent, information, application or request is delivered after the normal business hours of the party to whom it is sent, it is to be treated as having been given or made at the beginning of the next *Business Day*.

28. Miscellaneous

Governing law and jurisdiction

28.1 This document is governed by the law of the State of South Australia.

28.2 The parties submit to the non-exclusive jurisdiction of the courts of the State of South Australia.

28.3 The parties will not object to the exercise of judgment by the courts of the State of South Australia on any basis.

Severability

28.4 If a clause or part of a clause of this Negotiating Framework can be read in a way that makes it illegal, unenforceable or invalid, but can also be read in a way that makes is legal, enforceable and valid, it must be read in the latter way.

28.5 If any clause or part of a clause is illegal, unenforceable or invalid, that clause or part is to be treated as removed from this Negotiating Framework, but the rest of this Negotiating Framework is not affected.

Time for Action

28.6 If the day on or by which something is required to be done is not a *Business Day*, that thing must be done on or by the next *Business Day*.

29. Definitions and interpretation

29.1 Definitions

In this document the following definitions apply:

Business Day means a day on which all banks are open for business generally in Adelaide, South Australia.

Commercial Information will include at a minimum, the following classes of information in relation to a *Service Applicant*, where applicable:

a) details of corporate structure, financial details relevant to creditworthiness and commercial risk and ownership of assets;

b) technical information relevant to the application for a *Negotiated Distribution Service*;

c) financial information relevant to the application for a *Negotiated Distribution Service*;

d) details of an application's compliance with any law, standard, Rules or guideline.

Connection Services are those services defined in accordance with clause 8.1.

Connection assets means those assets which are used to provide *connection services* to a customer at a *connection point*.

Charges means the amount payable by a *Service Applicant* to *ETSA Utilities* in relation to the provision of a *Negotiated Distribution Service*.

Costs means any costs or expenses incurred by *ETSA Utilities* in complying with this Negotiating Framework or otherwise advancing the *Service Applicant's* request for the provision of a *Negotiated Distribution Service* or such other costs or expenses required to provide *Negotiated Distribution Services* to a *Service Applicant*, consistent with the

Rules, and in compliance with *ETSA Utilities'* Cost Allocation Methodology and any relevant part of a distribution determination applying to *ETSA Utilities*.

extension means works required for the connection of a customer's supply address outside the boundaries of ETSA Utilities' ***distribution network*** that existed at the time that the *Service Applicant's* application was made.

Indicative Price List means the indicative list of *prices* for *Indicative Price List Services* published under clause 20.

Indicative Price List Services are a classification of *Negotiated Distribution Services* in accordance with clause 3.1.

Individually Negotiated Services are a classification of *Negotiated Distribution Services* in accordance with clause 3.1.

Information Disclosure means the information that must be disclosed to *Service Applicants* for *Indicative Price List Services* as defined in Schedule 3.

ETSA Utilities means ETSA Utilities ABN 13 332 330 749.

Miscellaneous Services are a classification of *Individually Negotiated Services* in accordance with clause 8.1.

Negotiated Distribution Service(s) means those services defined as *Negotiated Distribution Services* in Attachment B.1 to *ETSA Utilities'* Regulatory Proposal.

Price(s) means the amount *(Charge)* payable by a *Service Applicant* to *ETSA Utilities* in relation to the provision of a *Negotiated Distribution Service*.

Service Applicant means the customer requesting the provision of a *Negotiated Distribution Service*.

Solvency Default means the occurrence of any of the following events in relation to the *Service Applicant*:

a) an originating process or application for the winding up of the *Service Applicant* (other than a frivolous or vexatious application) is filed in a court or a special resolution is passed to wind up the *Service Applicant*, and is not dismissed before the expiration of 60 days from service on the *Service Applicant*;

b) a receiver, receiver and manager or administrator is appointed in respect of all or any part of the assets of the *Service Applicant*, or a provisional liquidator is appointed to the *Service Applicant*;

c) a mortgagee, chargee or other holder of security, by itself or by or through an agent, enters into possession of all or any part of the assets of the *Service Applicant*;

d) a mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

e) the *Service Applicant* stops payment of, or admits in writing its inability to pay, its debts as they fall due;

f) the *Service Applicant* applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the *Service Applicant* or any of its property;

g) a court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the *Service Applicant's* property;

h) the *Service Applicant* takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the Corporations Act 2001), in respect of the *Service Applicant*;

i) a controller (as defined in the Corporations Act 2001) is appointed in respect of any part of the property of the *Service Applicant*;

j) except to reconstruct or amalgamate while solvent, the *Service Applicant* enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the *Service Applicant's* affairs;

k) the *Service Applicant* is the subject of an event described in section 459C(2)(b) of the Corporations Act 2001; or

l) anything analogous or having a substantially similar effect to any of the events specified above happens in relation to the *Service Applicant*.

29.2 Interpretation

In this document, unless the context otherwise requires:

a) terms defined in the NEL and the Rules have the same meaning in this Negotiating Framework;

b) a reference to any law or legislation or legislative provision includes any statutory modification, amendment or re -enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision;

c) a reference to any agreement or document is to that agreement or document as amended, novated, supplemented or replaced from time to time;

d) a reference to a clause, part, schedule or attachment is a reference to a clause, part, schedule or attachment of or to this document unless otherwise stated;

e) an expression importing a natural person includes any company, trust, partnership, joint venture, association, corporation, body corporate or governmental agency; and

f) a covenant or agreement on the part of two or more persons binds them jointly and severally.

Schedule 1. Classification of Negotiated Distribution Services

The categorisations of *Negotiated Distribution Services* in this table correspond to those defined in more detail in Attachment B.2 of ETSA Utilities Regulatory Proposal.

Negotiated Distribution Service	Classification of Service[8]	
'B.x' references refer to categorisations defined in Attachment B.2 of ETSA Utilities Regulatory Proposal	*Individually Negotiated Service*	*Indicative Price List Service*
B.7 Non-standard network services	All	
B.8 Non-standard *connection services*	Non-repetitive	Repetitive
B.9 New and upgraded connection point services	Non-repetitive	Repetitive
B.10 Non-standard small customer metering services		All
B.11 Large customer metering services		All
B.12 Public lighting services	Non-repetitive	Repetitive
B.13 Stand-by and temporary supply services	Non-repetitive	Repetitive
B.14 Asset relocation, temporary disconnection and temporary line insulation services	Non-repetitive	Repetitive
B.15 Embedded generation services	All	
B.16 Other services		
(a) services in connection to *ETSA Utilities'* Distribution licence obligations or the NER;	Non-repetitive	Repetitive
(b) provision of reactive power and energy to a connection point or receipt of reactive power and energy from a distribution connection point;		All
(c) investigation and testing services;	Non-repetitive	Repetitive
(d) asset location and identification services;	Non-repetitive	Repetitive
(e) the transportation of electricity not consumed in the distribution system;	All	
(f) the transportation of electricity to distribution network users connected to the distribution system adjacent to the transmission system;	All	
(g) repair of equipment damaged by a distribution network user or a third party;	All	
(h) provision of high load escorts;	Non-repetitive	Repetitive
(i) provision of protection systems;	All	
(j) Provision of pole or structure attachments, ducts or conduits;	Non-repetitive	Repetitive
(k) Additional costs arising from customer non-compliance with obligations;	Non-repetitive	Repetitive

[8] Shading indicates applicability of either the *Individually Negotiated Service* or *Price List Service* frameworks. Both frameworks apply to many services owing to the high variability of the scope and complexity of services within each category.

Negotiated Distribution Service *'B.x' references refer to categorisations defined in Attachment B.2 of ETSA Utilities Regulatory Proposal*	**Classification of Service**[8]	
	Individually Negotiated Service	*Indicative Price List Service*
(l) Customer default resulting in work not being able to be undertaken or completed as planned;	Non-repetitive	Repetitive
(m) TV or radio interference investigation where *ETSA Utilities*' network is not the cause;	Non-repetitive	Repetitive
(o) Investigation of supply interruption not due to *ETSA Utilities*' network; and	All	
(p) Provision of information not related to connection enquiries.	Non-repetitive	Repetitive

Schedule 2. 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).

Schedule 3. Information Disclosure for Indicative Price List Services

ETSA Utilities will make available, to any person to whom *Indicative Price List Services* are provided, and on its website, information describing:

a) The services for which an indicative *Price* is provided;

b) The indicative *prices* and rates for each *Indicative Price List Service*, or where it is not reasonably practicable to determine indicative *prices* or rates, the methodology by which the *prices* or rates will be determined;

c) The basis on which it has been determined that such *charges* are in compliance with the *Negotiating Distribution Service Criteria*; and

d) The terms and conditions on which each *Indicative Price List Service* is to be provided by *ETSA Utilities*.

In addition, *ETSA Utilities* will publish annually, a revised *Indicative Price List* detailing:

e) Any additions, removals or other modifications to the list of *Indicative Price List Services* from those previously published, and the basis of such changes; and

f) Reasonable changes to the pricing of *Indicative Price List Services* from those previously published and the basis of such changes

E. Changes to tariff structures

Changes to tariff structures can occur for customers in the following circumstances:

- the introduction of new tariffs or tariff components (for example, introducing a step rate for the usage component of the domestic tariff)
- adjustments to existing tariffs or tariff components (for example, changing the threshold on an inclining block tariff or the time bands associated with time of use tariffs). This situation is essentially the same as introducing new tariffs or tariff components
- when customers move between existing tariffs (from origin tariffs to alternative tariffs).

The weighted average price cap (WAPC) and side constraints formulas applying to the control mechanism will require adjustments for those tariffs subject to a change in structure. Specifically, adjustments will be required to:

- the historical quantity weights (q_{t-2}^{ij} and q_{t-2}^{j}) for these tariffs
- the values of the current tariffs/tariff components in the WAPC and side constraints formulas (p_{t-1}^{ij} and d_{t-1}^{j}).

This appendix sets out the approach to estimating the historical quantity weights and the substitute values for the current tariffs/tariff components to be used when calculating compliance with the WAPC and the side constraint formulas. For simplicity of presentation, any discussion in this appendix in relation to p_{t-1}^{ij} and q_{t-2}^{ij} (for the WAPC) should be taken to be equally applicable to d_{t-1}^{j} and q_{t-2}^{j} (for the side constraints).

E.1 Introducing new tariffs or tariff components

E.1.1 The value of q_{t-2}^{ij}

Both the WAPC and side constraints are calculated using audited historical quantities of consumption. However, historical quantities for any new tariffs/tariff components will not be available for two years.

In order to incorporate new tariff structures in the WAPC and the side constraints, the AER requires reasonable estimates to be submitted by the DNSP, based on the quantities that would have been sold if the new tariff/tariff components had been introduced in year ‘t–2’.

First, the DNSP must nominate the origin tariffs/tariff components, which represent the tariffs/tariff components that the customers, who will be moved to the new network tariffs/tariff components, are currently being charged.

Second, the DNSP must provide reasonable estimates of q_{t-2}^{ij} for all applicable units of measure (for example kWh, kW) for both the new tariffs/tariff components, and the origin tariffs/tariff components. The DNSP must make the following assumptions when calculating these reasonable estimates:

1. The only customers who would have moved to the new network tariff/tariff component in year t–2 did so due to a change in tariff structures initiated by the DNSP and as permitted under the customers' network connection contract. This means that no new customers are included in the estimate,[942] and nor are customers who request to change tariff either voluntarily, or through the actions of a retailer.
2. Customers have the same consumption and load profile on the new tariff/tariff component as they did on the origin tariff/tariff component. This implies that the sum of the reasonable estimates for year t–2 for each unit of measure on the new tariff/tariff component plus the reasonable estimates for year t–2 for each unit of measure on the origin tariff/tariff component, equals the actual audited quantities that occurred for the origin tariff/tariff component in year t–2.

In the year after a new tariff/tariff component has been introduced, there will still be no full year of audited historical data available to be used for q_{t-2}^{ij}. As a result the DNSP will be required to again submit reasonable estimates for both the new tariff/tariff component and the corresponding origin tariff/tariff component. At this time, however, the DNSP may base the reasonable estimates on the actual quantities that have occurred to date on the new tariff/tariff components and origin tariff/tariff components. The DNSP must demonstrate how it has arrived at the estimates.

E.1.2 The value of p_{t-1}^{ij}

The p_{t-1}^{ij} of the corresponding origin tariff/tariff components will be used as the p_{t-1}^{ij} for the new tariff/tariff components, where both the origin and new tariff components are measured in the same units of measure. If there is no corresponding origin tariff/tariff components with the same units of measure, p_{t-1}^{ij} will be set to zero.

E.1.3 Example 1: Introducing an inclining block tariff component

This example assumes that a domestic tariff with a single variable rate is amended so that there are now two variable rates based on a customer's level of consumption. For each of the 25 000 customers on this tariff, their historical consumption is split between consumption up to 5000kWh per annum and any residual consumption above this amount. Under this approach, the total consumption for this tariff class of 200 000MWh is split, 150 000MWh against variable rate 1 and 50 000MWh against variable rate 2 as shown in the example set out in table E.1.

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942 New customers have been allowed for in the growth assumption used when setting the X factor.

Table E.1: Determining p_{t-1}^{ij} and q_{t-2}^{ij} in example 1

Tariffs		p_{t-1}^{ij}	q_{t-2}^{ij}
Origin tariff – standard domestic			
Fixed charge	$ pa per customer	30	25 000 customers
Variable rate (all consumption)	c/kWh	0.04	200 000 MWh
Proposed tariff with new component			
Fixed charge	$ pa per customer	30	25 000 customers
Variable rate 1 (consumption ≤ 5000kWh pa per customer)	c/kWh	0.04 (as per origin tariff)	150 000 MWh
Variable rate 2 (consumption > 5000kWh pa per customer)	c/kWh	0.04 (as per origin tariff)	(200 000 –150 000) = 50 000 MWh

Note: While the variable rates (1 & 2) that the DNSP proposes for the next year (p_t^{ij}) are likely to differ, the divergence in these rates is constrained by the overall WAPC and the side constraints for this tariff class.

E.2 Customers transferred to an alternative tariff

E.2.1 The value of q_{t-2}^{ij}

The DNSP may decide to transfer customers if a customer's consumption or load profile has changed and the DNSP decides it is no longer appropriate for them to remain on the same tariff. Alternatively the DNSP may change the structure of an existing tariff to suit the majority of customers. Appendix B sets out the procedures a DNSP must adhere to in assigning or reassigning customers to tariff classes.

If the DNSP proposes to reassign a number of customers to an alternative existing tariff, the rate at which revenue will accrue from these customers will be different to that used to calculate the X factor and will be different to what will be calculated under the WAPC formula. In addition, the side constraint formula will not fully reflect the actual tariff change for the customers being transferred, as the overall tariff change observed by these customers will reflect not only the side constraint on the alternative tariff but the difference between the origin tariff the customer was on and the alternative tariff to which they are being transferred. In these circumstances, the AER will require the DNSP to submit reasonable estimates for q_{t-2}^{ij} for each origin tariff that the customer is currently on, and the new tariff that the DNSP will move the customers to, taking the transfer into account.

For compliance purposes, the DNSP must make the following assumptions when calculating the reasonable estimates:

1. the customer movement occurred in year t–2
2. the customers only moved as a result of a change in tariff structures initiated by

the DNSP and as permitted under the customers' network connection contract. The estimates are not to include customers who choose to move at their discretion or movements caused by a retailer's action

3. customers have the same consumption and load profile under either tariff.

Reasonable estimates will also be required in the year following the movement as there will still be no full year of audited historical data available.

E.2.2 The value of p_{t-1}^{ij}

The p_{t-1}^{ij} for the corresponding origin tariff/tariff components will be used as the p_{t-1}^{ij} for the new tariff components.

E.2.3 Example 2: Re-assigning some customers from the domestic flat rate tariff to the domestic TOU tariff

This example assumes 10 000 customers with consumption of 70 000 MWh will be moved by the DNSP from the domestic tariff to the domestic time of use (TOU) tariff, which already has 5000 customers. Both tariffs remain in existence and there will be customers on both. The allocation of the 70 000 MWh across the peak, shoulder and off–peak rates reflects historical consumption patterns of these customers and is shown in table E.2.

Table E.2: Determining p_{t-1}^{ij} and q_{t-2}^{ij} in example 2

Tariffs		p_{t-1}^{ij}	q_{t-2}^{ij}
Domestic			
Fixed charge	$ pa per customer	30	(25 000 existing – 10 000) = 15 000 customers
Variable rate (any time)	c/kWh	0.04	(200 000 existing – 70 000) = 130 000 MWh
Domestic TOU – existing customers			
Fixed charge	$ pa per customer	22	5 000 existing
Peak rate	c/kWh	0.09	10 000 MWh existing
Shoulder rate	c/kWh	0.05	10 000 MWh existing
Off–peak rate	c/kWh	0.02	10 000 MWh existing
Domestic TOU – customers being transferred			
Fixed charge	$ pa per customer	30 (as per domestic)	10 000 customers
Peak rate	c/kWh	0.04 (as per domestic)	25 000 MWh
Shoulder rate	c/kWh	0.04 (as per domestic)	20 000 MWh
Off–peak rate	c/kWh	0.04 (as per domestic)	25 000 MWh

Note: The Domestic TOU tariff the DNSP proposes for next year (p_t^{ij}) will apply equally across all (15 000) customers now on that tariff, which must be within the constraints of the WAPC and side constraints.

E.3 AER assessment of reasonable estimates

When assessing the reasonableness of quantity estimates provided by ETSA Utilities, the AER will take the following information into account:

1. the actual audited quantities sold in relevant units under the origin tariff in previous years
2. a forecast of the number of distribution customers that the DNSP states will move to the new tariff/tariff components, and the reasons for the move
3. a forecast of the number of distribution customers that the DNSP expects will remain on the origin tariff
4. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that are to be moved to the new tariff/tariff components
5. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that will remain on the origin tariff
6. a forecast of the distribution tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will be moved to the new tariff/tariff components
7. a forecast of the distribution tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will remain on the origin tariff
8. the approach the DNSP used to determine its forecasts (for 2–7 above)
9. the materiality of the reasonable estimates
10. further information as required by the AER.

F. Transmission use of system unders and overs account

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

As part of its pricing proposal for each regulatory year of the next regulatory control period, ETSA Utilities must provide the amounts for the following entries in its TUOS unders and overs account for the most recently completed regulatory year, the current regulatory year and the next regulatory year:

1. opening balance for each year
2. interest accrued on the opening balance for each year, calculated at the rate of the post–tax nominal rate of return as approved by the AER in its distribution determination
3. the amount of revenue recovered from TUOS charges applied in respect of that year, less the amounts of all transmission related payments made by the DNSP in respect of that year
4. six months interest on the net amount in item 3, accrued at the approved post–tax nominal rate of return
5. summation of the above amounts to derive the closing balance for each year.

ETSA Utilities must provide details of calculations in the format set out in table F.1 of this decision. Amounts provided for the most recently completed regulatory year must be audited. Amounts for the current and next regulatory year will be regarded as estimates and forecasts respectively.

In proposing variations to the amount and structure of TUOS charges, ETSA Utilities are to achieve a zero expected balance on its TUOS unders and overs account at the end of each regulatory year in the next regulatory control period.

For transitional purposes, no interest charge (in steps 2 and 4 above) will be applied to any unders and overs for 2008–09 and 2009–10. This transitional arrangement is to maintain consistency with ESCOSA’s current approach that did not index under and over amounts.

Table F.1: Calculation of TUOS unders and overs account ($'000)

	year t–2 (actual)	year t–1 (estimate)	year t (forecast)
Revenue from TUOS charges	36 221	36 836	40 968
Transmission charges to be paid to TNSPs	25 214	27 602	35 791
Avoided TUOS payments	572	638	681
Inter-DNSP payments	8579	9575	10 221
Total transmission related payments	34 365	37 816	46 694
Under/over recovery for financial year	1856	–980	–5726
Unders and overs account			
Annual rate of interest applicable to balances	9.70%	9.70%	9.70%
Half-year rate of interest	4.74%	4.74%	4.74%
Opening balance	3624[a]	5919[b]	5467
Interest on opening balance	351	574	530
Under/over recovery for financial year	1856	–980	–5726
Interest on under/over recovery	88	–46	–271
Closing balance	5919	5467	0

(a) The opening balance for year t–2 is based on the cumulative balance of actual under and over recoveries over the preceding years and using the same indexing approach for these actuals. In other words, in the example above, the reader could imagine additional columns before year t–2, presenting actuals for year t–3, year t–4 etc and which accumulate to the opening balance for year t–2.

(b) This balance will be the opening balance for year t–2 when the DNSP presents its next pricing proposal to the AER in 12 months time.

G. Cost escalators

This appendix sets out the AER's consideration of issues raised in response to the draft decision on labour and materials cost escalators for ETSA Utilities.

G.1 AER draft decision

The AER did not accept the methodologies used to develop the real cost escalators in ETSA Utilities' regulatory proposal. In particular, the AER did not consider ETSA Utilities' escalation rates for labour costs were acceptable because:[943]

- the forecasts developed by BIS Shrapnel in May 2009 were no longer based on the latest available information and expectations, specifically, expectations regarding the macro economic climate which underpinned the forecasts

- the internal labour growth forecasts explicitly reflected the impact of ETSA Utilities' internally determined performance and incentive initiatives, including bonus payments, which the AER considered had not been demonstrated to be efficient by ETSA Utilities

- the forecasts did not appear to accurately consider the actual composition of its internal and contract service labour resources by labour type.

In relation to materials cost escalators, the AER did not consider that the materials escalation rates were acceptable because they did not reflect the most up to date market–based forecasts of future materials costs.

The AER substituted ETSA Utilities' cost escalators with those set out in table G.1.

Table G.1: AER draft decision on ETSA Utilities' real cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Aluminium	–18.8	–12.0	20.2	16.1	5.5	1.6	0.4
Copper	–27.3	10.4	14.7	10.6	1.1	–2.6	–3.9
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
Materials	–2.14	–5.34	8.27	6.25	1.51	–0.25	–0.53
Labour	3.0	2.30	0.99	0.83	1.26	1.79	1.97
Services – construction related	2.10	1.32	–0.26	0.25	1.18	0.75	–0.19
Services – other outsourced	0.87	1.86	1.05	0.96	1.24	1.76	1.93

Source: AER, *Draft decision, SA draft distribution determination*, November 2009, appendix G.

943 AER, *Draft decision*, *SA draft distribution determination*, November 2009, appendix G.

G.2 Revised regulatory proposal

Labour

ETSA Utilities did not accept the AER's internal labour escalator. ETSA Utilities stated that while, in general, it had adopted the AER's labour escalation model, it amended the model to account for the impact of ETSA Utilities' Enterprise Bargaining Agreement (EBA).[944] ETSA Utilities considered the draft decision underestimated its actual EBA costs for 2008–09 and 2010–11, as the 2007–08 electricity, gas and water (EGW or utilities) sector data should not have been used to calculate 2008–09 labour cost growth when actual data was available.[945] Further, with respect to the EBA adjustment of 2010–11, ETSA Utilities considered that the July 2010 increment (in its 2008 EBA) would apply to the entire 2010–11 financial year and therefore, it would be inappropriate to truncate the cost escalation to only December 2010.[946]

ETSA Utilities noted that the application of the AER's real weighted average internal labour escalator in its revised regulatory proposal negates the AER's concerns with respect to ETSA Utilities' treatment of employee bonuses and incentives.[947]

Services

ETSA Utilities accepted the AER's approach to calculating real cost escalators for construction and other outsourced services. However, ETSA Utilities updated its construction related services escalator with the latest available data released from the Construction Forecasting Council (CFC).[948]

Materials

ETSA Utilities adopted all of the AER's recommendations in relation to materials cost escalators, except using LME 63 month and 123 month forward contract prices for aluminium and copper.[949] ETSA Utilities indicated that its consultant, SKM, was concerned that the extremely small volume of trades in these contracts made the associated price data unsuitable for interpolation. Instead, SKM used Consensus Economics long term forecasts to calculate ETSA Utilities' aluminium and copper escalators.[950]

ETSA Utilities stated that its materials escalators had been updated using the latest relevant forecast data.[951] ETSA Utilities' revised real cost escalators are presented in table G.2.

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944 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108, attachment F.10, pp. 7–8.
945 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, p. 6.
946 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, p. 7.
947 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 133.
948 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.
949 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.
950 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, pp. 3–4.
951 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.

Table G.2: ETSA Utilities' revised real cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Materials	–1.54	–2.60	9.46	3.80	–1.46	–2.44	–2.62
Labour	1.12	2.30	1.38	0.81	1.26	1.79	1.97
Services – construction related	0.13	3.15	0.75	0.08	0.72	0.49	–0.09
Services – other outsourced	0.87	1.86	1.05	0.96	1.24	1.76	1.93

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 108.

G.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 EGW sector for NSW, Victoria, Queensland, South Australia, ACT and Australia.[952]

Access Economics noted that changing economic conditions were the key driver for revisions to forecasts published in its September 2009 report.[953] However, Access Economics also noted that the following technical changes to historical variables have resulted in changes to its forecasts:[954]

- new industry projections used 2006–07 as the base year
- application of the new ANZSIC06 structure
- LPI measures were rebased to 2008–09.

South Australia labour growth forecasts

Access Economics noted that the technical changes have affected its detailed (industry by State) results, as outlined below:[955]

- 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 (AWE) measures were only available from June 2009, sectoral national growth rates were assumed.

952 Access Economics, *Forecast growth in labour costs: March 2010 report*, 16 March 2010. Note Access economics uses the term utilities sector rather than EGW in its report.
953 Access Economics, *Forecast growth in labour costs*, 16 September 2009.
954 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.
955 Access Economics, *Forecast growth in labour costs*, 16 March 2010, p. 48 and appendix F.

General labour

Access Economics noted the South Australian economy has generally grown at a slower rate than Australia as a whole, due to its slow manufacturing base and older population. Further, Access Economics considered that South Australia was not as susceptible to the negative effects of the recent downturn compared to other states and Australia as a whole. However, particularly weak growth was noted for the twelve months preceding September 2009, along with a fall in general wages growth below the national average.[956]

Access Economics projected South Australia's economic growth to record a solid recovery through 2010. Further to this, Access Economics forecast labour cost growth to peak in mid–2011, at 1.1 per cent, in real terms, before easing slightly and reverting back toward the national average.[957]

Access Economics' general labour forecasts are set out in table G.3 below.

Electricity, gas and water labour[958]

Access Economics stated growth in South Australia's EGW sector has compared well with national EGW sector growth, in addition to comparing well against South Australian general labour growth rates.

Access Economics considered that the South Australian EGW sector will face short term skill supply shortages, due to an ageing (and retiring) population and this will subsequently impact labour costs. It considered that South Australia can anticipate labour costs rising faster than that seen nationally, in order to retain current and attract new workers but this may be overshadowed in the medium term by lower productivity.[959]

Access Economics noted measured utilities wages grew steadily, against the trend, throughout the first half of 2009. More recently however, Access Economics noted EGW sector growth is more closely aligned with the national average. Access Economics projected this pattern to continue for some time, however the latter years of the next regulatory control period, notably from 2013 onwards, may see increases above trend growth rates for the South Australian EGW sector, as a result of the previously noted demographic impacts.[960]

Access Economics general labour forecasts are set out in table G.3 below.

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[956] Access Economics, *Forecast growth in labour costs,* 16 March 2010, pp. 30–31.
[957] Access Economics, *Forecast growth in labour costs,* 16 March 2010, pp. 30–31.
[958] The AER notes the release of 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.
[959] Access Economics, *Forecast growth in labour costs,* 16 March 2010, pp. 80–81.
[960] Access Economics, *Forecast growth in labour costs,* 16 March 2010, p. 81.

Table G.3: Access Economics real labour escalation rates for general labour and the EGW sector in South Australia

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
General	0.7	0.8	1.1	0.2	0.5	1.2	1.5
EGW	1.7	2.3	1.2	0.3	0.5	1.2	1.6

Source: Access Economics, *Forecast growth in labour costs*, 16 March 2010, p. 79.

G.4 Submissions

The Electricity Consumers Coalition of South Australia (ECCSA) raised concerns in relation to real cost escalation. In particular, ECCSA stated that the AER view appears to be that any real increase in costs is justification for an increased allowance to the regulated business.[961]

In relation to wages growth, ECCSA considered that the AER has taken an overly conservative approach.[962] ECCSA stated that the AER must include a productivity gain to offset wage growth, in keeping with jurisdictional regulators. ECCSA recommended that the state-wide increases in wages be the surrogate to establish the productivity benchmark for ETSA Utilities.[963]

In relation to materials cost escalation, ECCSA stated that the AER should not adopt an approach of forecasting materials price growth. ECCSA stated such forecasts will invariably be conservative in favour of the businesses. ECCSA also stated businesses have historically demonstrated the capacity to absorb materials cost variation within their capex allowances adjusted by CPI. ECCSA therefore proposed that the AER should only make allowances for defined step changes in business conditions.[964]

G.5 Issues and AER considerations

Labour

The AER notes that ETSA Utilities accepted the AER’s internal labour escalators, with the exception of those for 2008–09 and 2010–11.

As noted in the draft decision, the AER considered it reasonable to adopt actual wage increases provided for under ETSA Utilities’ EBA up until 2009–10.[965] In the AER’s modelling of ETSA Utilities’ labour costs, the escalation rate for 2008–09 did not reflect the actual impact of ETSA Utilities’ 2005 EBA. ETSA Utilities has provided actual EBA impacts which the AER has used in its modelling instead of EGW data provided by Access Economics. As a result, in this decision the AER has applied the 2008–09 escalation rate for internal labour proposed by ETSA Utilities.

[961] ECCSA, *A response*, February 2010, p. 19.
[962] ECCSA, *A response*, February 2010, p. 20.
[963] ECCSA, *A response*, February 2010, p. 21.
[964] ECCSA, *A response*, February 2010, p. 21.
[965] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 477.

ETSA Utilities' observed that the AER's modelling of labour escalators for the draft decision included EBA rates to December 2010, thereby impacting labour escalation rates in 2010–11. This was a modelling error and may explain why ETSA Utilities misinterpreted the AER's intention to apply EBA wage increases 'until the end of the current agreement'.[966] Rather, as stated in the draft decision, the AER considered it reasonable to adopt current EBA wage increases up until 2009–10.

The AER maintains its view in the draft decision and previous regulatory decisions[967] that it is not appropriate to uncritically apply a DNSP's current EBA rates into the next regulatory control period, as this 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 EBA impacts in 2010–11 for this decision.

The AER notes that ETSA Utilities considered that both its historical and future EBA negotiated outcomes were prudent and efficient for a range of reasons, including: [968]

- the controlled and difficult environment within which they were negotiated
- its EBA benchmarked well with relevant historical national averages
- the EBAs dominate wage movements in the EGW sector and EBA arrangements run for an average of three years.

The AER does not consider that these arguments represent sufficient demonstration that ETSA Utilities' EBA rates represent an efficient level of labour cost escalation, for the following reasons:

- ETSA Utilities' EBA[969] came into effect prior to the global financial crisis (GFC),[970] and therefore would not reflect the impact and uncertainty of GFC-associated economic conditions on labour growth
- 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 EBA wage negotiated outcomes that ETSA considered benchmarked well with relevant historical national averages[971]

966 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, p. 6.
967 AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p. 493.
968 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, p. 9.
969 ETSA Utilities, *Response to AER.EU.15*, 4 September 2009.
970 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.
971 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, p. 9. This approach is consistent with that of the AER's NSW/ACT final determinations.

- the outcomes from any specific wage negotiation, regardless of the nature of the negotiation, do not necessarily reflect efficient labour costs for the industry as a whole.

As a result of the above review and analysis, the AER does not consider the application of EBA outcomes on ETSA Utilities' internal labour escalation rates in the next regulatory control period reflect realistic and efficient costs. Further to this, and as foreshadowed in the draft decision, the AER considers that to develop a robust forecast it is appropriate to update the forecast labour cost using the most recent data.[972] The AER therefore considers it appropriate to apply the updated Access Economics labour cost growth forecasts for South Australia to derive internal labour cost escalators for ETSA Utilities.

The AER confirms the draft decision to apply ETSA Utilities' EBA escalation rates up until 2009–10 to reflect actual costs incurred by ETSA Utilities.[973] For the next regulatory control period, the AER has applied Access Economics' updated EGW and general labour forecasts for South Australia to determine ETSA Utilities' weighted average internal labour escalator for ETSA Utilities' forecast internal labour costs, based on the weights outlined in the draft decision.[974]

The AER notes the concerns raised by ECCSA that the AER took a conservative approach for wage cost growth and considered state-wide wage increases should be treated as a benchmark for productivity. The AER considers that productivity adjustments can be an important factor in forecasting actual business costs and notes this approach is consistent with previous regulatory decisions.[975] The AER further notes Access Economics considers productivity factors as a key driver of wage differentials and has incorporated productivity into its modelling.[976] The AER supports the application of Access Economics' productivity impacts in the modelling of its wage cost growth forecasts and does not consider it necessary to include further productivity adjustments. The AER considers Access Economics wage cost growth forecasts reflect a realistic expectation of labour costs.

AER conclusions

The AER's conclusions on ETSA Utilities' weighted average internal labour cost escalator are presented in table G.4.

For the reasons discussed and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, consultants' reports and other material, the AER is satisfied that the application of the updated internal labour cost escalator to ETSA Utilities' opex and capex forecasts 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.

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972 AER, *Draft Decision, SA Draft distribution determination*, November 2009, p. 475.

973 AER, *Draft Decision, SA Draft distribution determination*, November 2009, p. 477.

974 AER, *Draft Decision, SA Draft distribution determination*, November 2009, p. 476.

975 AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14,* 28 April 2009, p. 492.

976 Access Economics, *Forecast growth in labour costs,* 16 March 2010, appendix C, p. 106.

Contract Services – construction related

ETSA Utilities accepted the AER's approach to deriving its weighted average escalator for construction related contracts to be applied to its construction related contract services. However, ETSA Utilities applied updated construction cost forecasts and CPI forecasts to November 2009, derived by KPMG Econtech.[977]

As foreshadowed in the draft decision, the AER considers that to develop a robust forecast it is appropriate to update the forecast construction related contract services cost escalators using the most recent data.[978] The AER therefore considers it appropriate to apply the updated construction cost forecasts from CFC.

Further to this, and as per the AER's draft decision[979], the AER has incorporated Access Economics' updated EGW labour forecasts and forecast South Australian construction LPI to determine ETSA Utilities' weighted average escalator for construction related contracts, based on the weights outlined by ETSA Utilities.

AER conclusions

The AER's conclusions on ETSA Utilities' real construction related contract services cost escalator are presented in table G.3.

For the reasons discussed and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, consultants' reports and other material, the AER is satisfied that the application of the updated construction related contracts services cost escalator to ETSA Utilities' capex and opex 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.

Materials

In response to concerns raised by ETSA Utilities, 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 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.[980] While

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977 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment F.10, p. 11.
978 AER, *Draft Decision, SA Draft distribution determination*, November 2009, p. 477.
979 AER, *Draft Decision, SA Draft distribution determination*, November 2009, p. 481.
980 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.

these prices may reflect actual trades, the AER understands that they are established irrespective of whether any actual trades take place.[981]

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 ETSA Utilities' revised proposal to use Consensus Economics long term forecasts to establish cost escalators for aluminium and copper.

ECCSA suggested that the AER should not forecast changes in real costs incurred by the DNSPs.[982] The AER notes the NER requirement that the capex and opex forecasts should reflect a realistic expectation of cost inputs required to achieve the capex and opex objectives.[983] In previous decisions, the AER considered that cost escalation at CPI did not reflect a realistic expectation of the movement in some of the input costs faced by electricity network service providers. However, the remainder of materials costs, which on average account for around 75 per cent of DNSPs' total materials costs, are subject to cost escalation at CPI – that is zero real cost escalation.

The AER's approach to real cost escalation is that it should be applied symmetrically to reflect real cost increases and decreases.[984] This approach provides the opportunity for network service providers to recover the efficient costs of real increases, while ensuring that end users receive the benefit of real cost reductions. While conditions in commodity and labour markets have resulted in real cost increases in previous years, the AER notes that real costs do not always increase. For example, the cost of aluminium, copper, steel and oil all fell as a result of the global financial crisis and were expected to decline again following a period of recovery. These impacts are evident in the revised materials cost escalators proposed by ETSA Utilities, as shown in table G.2. These indicate negative real cost growth for five of the seven years over which base year costs are escalated. The AER therefore disagrees with ECCSA's view that materials cost forecasts will invariably be conservative in favour of the DNSPs.

AER conclusions

For the reasons discussed and as a result of the AER's consideration of ETSA Utilities' revised regulatory proposal, consultants' reports and other material, the AER considers that the method adopted by ETSA Utilities to forecast materials costs provides a realistic expectation of the real materials costs required for ETSA Utilities to achieve the capex 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.[985] The AER considers that this is the minimum adjustment necessary to

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[981] 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.

[982] ECCSA, *A response*, February 2010, p. 21.

[983] NER, clauses 6.5.6 (c) and 6.5.7(c).

[984] AER, *Final Decision, SP AusNet transmission determination 2008–09 to 2013–14*, January 2008, p. 80.

[985] AER, *Draft Decision, SA Draft distribution determination*, November 2009, p. 458.

ensure that the material cost escalators used by ETSA Utilities provide a realistic expectation of real material costs. The updated real materials cost escalators are presented in table G.4.

G.6 AER conclusion

Based on the most recent data at the time of this decision and the methodology proposed by ETSA Utilities in its revised regulatory proposal, the AER's conclusions on real cost escalators for this decision are presented in table G.4. The AER requested ETSA Utilities to update its composite materials cost escalator to reflect the updated material cost inputs. The composite materials cost escalation rates are also presented in the table G.4.

Table G.4: AER conclusions on ETSA Utilities' 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	0.720	0.738
Inflation rate	1.46	3.00	2.50	2.75	2.50	2.50	2.50
Materials[a]	–3.05	–3.84	9.32	–0.46	–0.06	–1.02	–1.34
Labour	1.12	1.80	0.57	0.29	0.52	1.18	1.56
Services – construction related	0.15	1.59	0.63	0.96	2.04	2.21	1.22
Services – other outsourced	0.94	1.17	1.11	0.25	0.51	1.22	1.54

Source: AER analysis.
(a) This composite materials cost escalator is based on ETSA Utilities' application of the materials cost inputs above. Source: ETSA Utilities, Response to AER expenditure modelling request for ETSA, 13 April 2010.

H. Self insurance

This appendix sets out the AER's assessment of ETSA Utilities' proposed self insurance allowances in their opex forecasts for the next regulatory control period.

H.1 AER draft decision

The AER did not accept ETSA Utilities' proposed self insurance allowance. In particular, the AER considered that the most appropriate self insurance allowances for property/poles and wires risks, motor vehicle risks, GSL payments, and underground damage and environmental liability risks were zero.[986]

The AER also considered that the self insurance allowances proposed by ETSA Utilities in regard to public liability did not reflect the opex criteria, including the opex objectives. Using the information that was available to the AER at the time, the AER calculated ETSA Utilities' public liability self insurance premium as $422 per annum.[987]

The AER accepted ETSA Utilities' proposed self insurance allowance for worker's compensation risks, as ETSA Utilities is a registered self insurer for worker's compensation with WorkCover SA, and worker's compensation is an unavoidable risk in the electricity distribution industry.[988]

The AER assessed ETSA Utilities' self insurance proposal against the following five principles:[989]

- 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.

The draft decision for ETSA Utilities' proposed self insurance allowance is shown in table H.1.

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986 AER, *Draft decision*, *South Australian draft distribution determination 2010–11 to 2014–15*, November 2009, appendix H, *Self insurance*.
987 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 496–497.
988 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 504–505.
989 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 485–491.

Table H.1: AER draft conclusion on ETSA Utilities' self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Property/poles and wires risks	0	0	0	0	0	0
Liability risks	.0004	.0004	.0004	.0004	.0004	.002
Motor vehicle risks	0	0	0	0	0	0
GSL payments	0	0	0	0	0	0
Underground damage and environmental liability	0	0	0	0	0	0
Worker's compensation	0.6	0.6	0.7	0.7	0.7	3.3
AER approved self insurance allowance	0.6004	0.6004	0.7004	0.7004	0.7004	3.3002

Source: AER, *Draft decision, SA draft distribution determination*, November 2009, appendix H.
Note: Totals may not add due to rounding.

H.2 Revised regulatory proposal

ETSA Utilities resubmitted its original self insurance proposal, with adjustments to reflect changes in cost escalators, as per the draft decision. Its proposed self insurance allowance is shown in table H.2.

Table H.2: ETSA Utilities' self insurance forecast ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Baseline costs[a]	3.6	3.6	3.6	3.6	3.6	18.0
Variation[b]	3.3	3.5	3.6	3.7	3.9	18.0
Total self insurance[c]	6.9	7.1	7.2	7.3	7.5	36.0

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment OX117, confidential.
Note: Totals may not add due to rounding.
(a) Baseline costs are self insurance premiums that were incurred in the 2008–09 base year. These costs are included in other opex categories other than self insurance.
(b) Variation costs represent the difference between the baseline costs in ETSA Utilities 2008–09 base year and the self insurance premiums recommended by AON Global Risk Consulting (AON Global).
(c) Total self insurance is the summation of the baseline and variation self insurance premiums.

ETSA Utilities' disagreed with the draft decision regarding self insurance. ETSA Utilities considered the AER had misunderstood its self insurance proposal, stating that the AER did not understand that there were self insurance baseline costs included within the opex forecasts. ETSA Utilities considered that the opex forecasts were examined and assessed as being reasonable in chapter 8 of the draft decision, and thus the AER should only have been examining the variation costs in the self insurance appendix.[990] ETSA Utilities also stated the AER did not understand that ETSA Utilities included costs associated with below deductible events, which could be forecast with certainty, within the self insurance cost category. ETSA Utilities considered the AER did not understand the types of events that it sought to be recovered as self insurance costs.[991]

ETSA Utilities stated it used the term self insurance to assist with its internal risk management policies which assist in managing costs and the use of the term 'self insurance' should not in itself be a reason to reduce expenditure to zero. It noted cost categories included within self insurance and referring to damage to poles and wires, and motor vehicle deductibles, for example, are business as usual costs.[992]

H.3 Submissions

Citipower and Powercor

Citipower and Powercor made a joint submission.[993] They stated the aim to minimise the total cost of insurable risk is in line with the AER's objective of utilising the most efficient techniques of managing risk.[994] They also stated that if an external insurance policy is to be used as an efficiency benchmark then it needs to be made on a like for like basis.[995]

United Energy

United Energy expressed concern that the AER appeared to consider the cost pass through mechanism provided a better incentive to control costs than self insurance. It submitted that self insurance provided stronger incentives to minimise costs than the cost pass through mechanism.[996] It also submitted that no costs are uncontrollable in an absolute sense and that the AER's standard approach in this respect is unworkable.[997]

SP Ausnet

SP Ausnet raised concerns that the AER's approach represented a departure from regulatory precedent.[998] SP Ausnet disagreed with the AER's comments surrounding self insurance of key assets, stating that if a key asset were impaired, a DNSPs ability to raise funds would not be affected due to a DNSPs geographical spread of assets.[999]

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990 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, *Detailed response – self insurance*, p. 1 and p. 11.

991 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 1.

992 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, pp. 2–3.

993 Citipower and Powercor, *Self insurance assessment*, 12 February 2010.

994 Citipower and Powercor, *Self insurance assessment*, 12 February 2010, attachment, AON Global, Reply to draft ETSA determination, February 2010, p. 2.

995 Citipower and Powercor, *Self insurance assessment*, 12 February 2010, attachment, AON Global, Reply to draft ETSA determination, February 2010, p. 5.

996 United Energy, *Submission to the AER*, February 2010, pp. 1–2.

997 United Energy, *Submission to the AER*, February 2010, p. 2.

998 SP Ausnet, *Submission to the AER*, February 2010, p. 2.

999 SP Ausnet, *Submission to the AER*, February 2010, p. 2.

SP Ausnet also submitted the AER's preference for cost pass through exposes DNSPs to risk for costs below the materiality threshold.[1000] Further, it stated self insurance naturally incentivises the DNSP to ensure that costs related to a self insured event are minimised.[1001]

Energex

Energex made a submission in relation to the draft decision for the Queensland DNSPs.[1002] Energex raised concerns about the reporting requirements that were outlined by the AER in relation to self insurance.[1003]

H.4 Issues and AER considerations

H.4.1 AER general issues and considerations

The AER notes ETSA Utilities' comment regarding the AER's acceptance of the baseline levels of self insurance that were incorporated within other categories of ETSA Utilities' opex proposal. While the AER provided a self insurance allowance of $0 for several proposed self insurance categories, the AER accepted that certain costs, such as the business as usual costs included within ETSA Utilities' self insurance proposal, were acceptable costs. The AER did not provide an allowance for these acceptable costs within another building block within the draft decision. However, the AER considers that these costs can be reclassified from self insurance to other opex categories. Thus, while rejecting certain costs as self insurance costs, the AER has reclassified these costs to other opex categories in this decision.

In the draft decision, the AER applied a principled approach in its assessment of ETSA Utilities' self insurance proposal. 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:[1004]

- 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.

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 has augmented its approach with the following consideration:

[1000] SP Ausnet, *Submission to the AER*, February 2010, p. 4.
[1001] SP Ausnet, *Submission to the AER*, February 2010, pp. 2–3.
[1002] Energex, *Submission on the draft determination*, February 2010.
[1003] Energex, *Submission on the draft determination*, February 2010, pp. 27–28.
[1004] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 486.

- 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.[1005]

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 this decision. The AER has incorporated the consideration surrounding consistency with the EBSS into its analysis in this decision.

H.4.2 Property risks/poles and wires

AER draft decision

The AER considered ETSA Utilities had the ability to meet any costs arising from damage to property and poles and wires through its capex and opex programs. In addition, the AER noted the inclusion of loss of value within the property damage category, and considered that loss of value was unsuitable for self insurance as it did not relate to an incurred cost for regulatory purposes.[1006]

Revised regulatory proposal

ETSA Utilities confirmed the self insurance costs related to property damage/poles and wires as set out in table H.3.

Table H.3: ETSA Utilities proposed property damage/poles and wires risks self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base line	1.4	1.4	1.4	1.4	1.4	7.1
Variation	0.4	0.4	0.5	0.5	0.6	2.5
Total self insurance	1.8	1.9	1.9	2.0	2.0	9.6

Source: ETSA Utilities, *Revised regulatory proposal*, Attachment G.5, *Detailed response – self insurance*, p. 19.

ETSA Utilities stated it had included baseline self insurance allowances for property risks within the 'risk management' opex category, while including a baseline self insurance allowance for poles and wires risks within the 'emergency response' category. ETSA Utilities observed the AER had made no adjustment to either risk management or emergency response in the opex chapter. Given this, it argued the AER had therefore accepted the baseline self insurance allowances for property risks and poles and wires as efficient.

ETSA Utilities noted the AER's argument that costs associated with these events could be addressed through the emergency response category or through costs that would be capitalised. ETSA Utilities stated that in accordance with its capitalisation

1005 AER, *Final decision, Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008, Attachment E – Efficiency benefit sharing scheme, p. 6.
1006 AER, *Draft decision*, *SA draft distribution determination*, November 2009, pp. 135–137.

policy and cost allocation methodology, the costs referred to in this section are opex rather than capex costs.[1007] While it conceded that these costs may be recouped through the opex program, ETSA Utilities stated these costs would have to be allowed in the cost build up to the expenditure program.[1008]

ETSA Utilities also noted the AER's comments regarding the possibility, if material, of these costs being recouped via the pass through mechanism. However, ETSA Utilities considered that this was impractical, as there are approximately 400 occurrences each year in relation to poles and wires third party damage alone. Further, based on the materiality thresholds, ETSA Utilities concluded that there was a question as to whether a pass through could be used to recover these costs.[1009]

ETSA Utilities made reference to a precedent for an allowance being provided for risks similar to property/poles and wires risks from the AER's Powerlink transmission draft decision, where self insurance was allowed for 'uninsurable risks – transmission structures and lines'.[1010]

ETSA Utilities provided a quote to insure the deductible for property damage. The quote indicated that to fully insure the deductible on ETSA Utilities' property damage insurance policy would cost in the order of $[redacted] per annum, which is significantly higher than the self insurance amount proposed.[1011]

ETSA Utilities considered the draft decision should be reversed, as the self insurance costs proposed satisfied the NER requirements.[1012]

Issues and AER considerations

The AER outlined in its draft decision that it considered DNSPs could fund excess emergency response costs through either opex or capex allowances as expediency dictated, in a similar fashion to the funding of excess storm damage to the network from this opex cost category.[1013]

ETSA Utilities stated costs related to poles and wires damage from third parties is expensed rather than capitalised. The AER notes that ETSA Utilities' capitalisation policy includes comments regarding the capitalisation of poles that were damaged by third parties.[1014] ETSA Utilities clarified that poles damaged by third parties are capitalised, however any unrecoverable amounts are later expensed.[1015] The AER considers that ETSA Utilities provided enough information to demonstrate that it does not capitalise non–recoverable damage to poles and wires from third party damage.

[1007] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, pp. 15–6.
[1008] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 17.
[1009] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 17.
[1010] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 17–8.
[1011] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 19 and appendix A –Indicative cost for insurance.
[1012] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 21.
[1013] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 494.
[1014] ETSA Utilities, *Regulatory proposal*, June 2009, CX 104, pp. 22–23.
[1015] ETSA Utilities, email response, AER.EU.RP.8, 23 February 2010, ETSA Utilities self insurance issues template, pp. 3–4.

The AER notes ETSA Utilities' stated poles and wires risks are business as usual costs that occur on a regular basis.[1016] ETSA Utilities further stated there are more than 400 events associated with non–recoverable third party damage to ETSA Utilities' property and poles and wires each year.[1017] The AER agrees that these costs are business as usual, and accepts these costs should be included within the forecast opex allowance. However, as they are a business as usual cost, these costs should be excluded from the self insurance category. This is consistent with the AER's decision on the efficiency benefit sharing scheme (EBSS) to be applied nationally.[1018] The AER stated:[1019]

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

The AER considers that 'an ongoing business activity' and a 'business as usual' activity are synonymous. As such, in line with the AER's decision on the EBSS, business as usual costs should not be included with self insurance.

The AER considers that, while these costs should be given a self insurance allowance of $0, it is reasonable for ETSA Utilities to include these costs within other opex categories. As such, the AER considers that costs associated with property and poles and wires risks should be transferred from self insurance to be incorporated within other opex categories.

The AER considers that the baseline costs, escalated for network growth, provide a reliable estimate of costs that would be expected to be incurred in relation to third party damage to poles and wires.

The AER considers that the cost incurred within the 2008–09 base year in relation to poles and wires risks is at a level that is consistent with ETSA Utilities' incurred loss history.[1020] The AER considers that ETSA Utilities and AON have not provided sufficient rationale for why the variation amounts in excess of the escalated baseline figures are necessary to reflect the estimated incurred cost. The AER therefore rejects the variation amounts for poles and wires risks.

The AER accepts the variation amounts in relation to property risks as the base year had relatively few losses related to property risks, when compared to the actual loss history.[1021]

The AER reviewed the escalation of ETSA Utilities property and poles and wires risks as part of the process of including these costs within the opex allowance and determining whether the proposed cost represents an efficient cost. The AER noted ETSA Utilities had escalated property and poles and wires risks twice for the same

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[1016] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 2 and p. 16.
[1017] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 20–21.
[1018] AER, *Final decision, Electricity DNSPs EBSS*, June 2008.
[1019] AER, *Final decision, Electricity DNSPs EBSS*, June 2008, *attachment E – Efficiency benefit sharing scheme*, p. 6.
[1020] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment OX117.
[1021] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment OX117.

factor—through escalating these costs within the self insurance derivation spreadsheet and then within the opex model.[1022] ETSA Utilities stated that it had made an error by applying this double escalation. ETSA Utilities removed the effects of the second escalation which resulted in a reduction in emergency response opex of $0.7 million over the next regulatory control period.[1023]

In addition, the AER requested that ETSA Utilities remodel an error that was made in the escalation within the self insurance derivation model. ETSA Utilities used 2008–09 figures rather than 2007 figures within the model for several event categories. ETSA Utilities advised that the correction of this error resulted in a reduction to property and poles and wires risks costs of $0.4 million over the next regulatory control period.[1024]

Summary

The AER considers that property and poles and wires risks are business as usual costs, and as such should be removed from the self insurance category and accounted for within another opex category in accordance with the EBSS.

The AER's adjustments relating to this opex category are as follows:

- $0.5 million reduction to remove the poles and wires risks variation
- $0.7 million reduction to remove double escalation
- $0.4 million reduction to remove double inflation.

The AER's conclusion is shown in table H.4.

Table H.4: AER conclusion on opex allowance for property and poles and wires risks ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	1.8	1.9	1.9	2.0	2.0	9.6
AER adjustments	–0.2	–0.3	–0.3	–0.4	–0.4	–1.6
Total property/poles and wires risks opex	1.6	1.6	1.6	1.6	1.6	7.9

Note: Totals may not add due to rounding.

H.4.3 Liability risks

AER draft decision

The AER considered the proposed self insurance allowance for liability risks did not accurately reflect the opex criteria and the opex objectives. On the basis of the

[1022] ETSA Utilities, *Revised regulatory proposal*, January 2010, Opex model, worksheet DA–15, and attachment OX711, *Derivation of self insurance forecast – updated*, 23 February 2010.
[1023] ETSA Utilities, email response, AER.EU.RP.8, 23 February 2010, Attachment 4, p. 2.
[1024] ETSA Utilities, email response, AER.EU.RP.8, 26 February 2010, ETSA Issues template – No. 2.

information provided about ETSA Utilities' external insurance policies, the AER considered the appropriate allowance for liability risks was $422 per annum.[1025]

Revised regulatory proposal

ETSA Utilities confirmed the self insurance costs related to liability risks as set out in table H.5.

Table H.5: ETSA Utilities proposed liability risks self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base line	0.6	0.6	0.6	0.6	0.6	2.8
Variation	1.9	2.0	2.0	2.0	2.0	9.9
Total self insurance	2.5	2.5	2.6	2.6	2.6	12.8

Source: ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, Detailed response – self insurance, p. 26.

ETSA Utilities stated it was aware of a claim of more than $5 million in relation to a bushfire at Port Lincoln in early 2009. ETSA Utilities' baseline expenditure does not reflect this claim, although AON Global's proposed variation does take account of this pending claim.[1026]

ETSA Utilities stated it included $2.8 million relating to liability risks within the risk management opex category. ETSA Utilities noted that in the draft decision, the AER did not recommend any adjustments to the risk management category. ETSA Utilities stated the AER had therefore accepted the baseline public liability expenditure included within risk management.[1027]

Further, ETSA Utilities submitted that the AER's calculation of the public liability premium failed to understand the layering of insurance risks and costs. ETSA Utilities outlined that when considering insurance claims, there are usually more events in the lower cost bands than in the higher cost bands. ETSA Utilities stated the reason deductibles are built into insurance policies is to deal with the frequency and lower costs associated with the majority of events.[1028]

ETSA Utilities obtained an indicative quote to insure the deductible. This quote indicated that to insure the entire deductible of its liability insurance policy, ETSA Utilities would need to pay in the order of $[redacted] to $[redacted] per annum. ETSA Utilities noted the AER's self insurance allowance of $422 per annum is at odds with this indicative quote.[1029]

[1025] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 496–497.
[1026] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 22.
[1027] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 22.
[1028] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 23.
[1029] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 24–5 and appendix A – Indicative cost for insurance.

For these reasons, ETSA Utilities considered its original proposed self insurance allowance for liability risks was efficient and prudent.[1030]

AER issues and considerations

In the draft decision, the AER determined an allowance of $422 per annum in relation to public liability self insurance. This allowance was determined using a linear relationship between the external insurance premiums paid and the amount being self insured. The AER considered that an external insurance quote should be used as a maximum efficient benchmark when assessing self insurance proposals.[1031]

In deriving what it considered as the best estimate of the efficient premium for public liability, the AER stated:[1032]

> The AER recognises that the deductible will have a higher premium associated with it due to the higher probability of events occurring within this band. This is compared to events over the deductible which, as the liability costs go higher, have a decreasing probability of occurring and thus attracts a lower premium per dollar insured. However, in the absence of a formal quote, or the provision of similar information illustrating the external cost to insure the deductible the premium paid on external insurance policies should be utilised as an estimate of the efficient cost.

The AER's estimate was a proxy based on the information available at the time. The AER noted the 'layering' of insurance policies and recognised that infrequent, higher cost events are cheaper to insure than more frequent low cost public liability events.

The AER has had regard to the insurance quote provided by ETSA Utilities in relation to public liability risks.[1033] This additional information has led the AER to reconsider its approach and recommendation for using an external insurance quote as a maximum efficient benchmark.

ETSA Utilities stated that it had received an informal quote estimating that it would cost approximately $[redacted] to $[redacted] per annum to externally insure the deductible.[1034] The AER considers that this shows that the market to insure the below deductible public liability costs for ETSA Utilities is an inefficient market, as insurers are reticent to lower the deductibles on public liability policies. This appears to be especially relevant in relation to bushfire liability risks. ETSA Utilities advised the AER that due to current conditions within insurance markets, ETSA Utilities' insurer would be increasing the fire liability deductible from $[redacted] to $[redacted] in 2010.[1035] The AER also notes these external quotes would not reflect the efficient cost to self insure due to the addition of profit margins, plus an inclusion of a large risk margin due to the elimination of the deductible which would create a 'moral hazard' situation. The AER considers that, while a self insurance premium should never be larger than these external quotes, these quotes must be used with caution when assessing the efficient self insurance premium.

[1030] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 27.
[1031] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 496.
[1032] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 496.
[1033] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5.
[1034] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 2.
[1035] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 22.

The AER considers that 'attritional' liability claims, or low cost, frequent liability claims, are better characterised as business as usual costs and should be excluded from self insurance and reclassified as a controllable opex category. This is in accordance with the AER's sixth self insurance principle, whereby 'business as usual costs' or 'ongoing business activities' should not be included within the self insurance category. The AER requested ETSA Utilities to remodel its liability risk claims, excluding the attritional claims below $100 000 per event, consistent with the approach that was taken in the Queensland distribution determination. ETSA Utilities advised the AER that this resulted in a split of approximately 70 per cent of claims falling into the attritional category, with 30 per cent falling into the large and bushfire claims category. The AER applied these ratios to determine that $8.5 million of liability claims falling within the attritional liability claims category below $100 000 per event, and $3.7 million falling into the large liability claims category.[1036]

In addition, the AER requested ETSA Utilities to remodel an error that was made in the escalation within the self insurance derivation model. ETSA Utilities advised that the correction of this error resulted in a reduction to liability risks of $0.6 million over the next regulatory control period.[1037]

Summary

The AER's adjustments relating to this self insurance category are as follows:

- $0.6 million reduction to remove double inflation
- attritional liability claims below $100 000 per event reclassified as a controllable opex category as these losses are 'business as usual' costs.

Other than these reductions, the AER considers that the derivation of the liability risk self insurance premium is reasonable as it is based on several years of historical liability losses that enable an efficient premium to be determined.

The AER has considered the information provided by ETSA Utilities in response to the draft decision and has accepted the proposed self insurance premium, subject to the correction of the modelling error identified and the reclassification of the attritional liability claims. The self insurance forecast for liability risks is shown in table H.6.

[1036] ETSA Utilities, email response, AER.EU.RP.14, 19 March 2010.
[1037] ETSA Utilities, email response, AER.EU.RP.8, 26 February 2010, ETSA Issues template – No. 2.

Table H.6: AER conclusions on ETSA Utilities' self insurance forecast for liability risks ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	2.5	2.5	2.6	2.6	2.6	12.8
Attritional liability claims reclassified as controllable opex	1.7	1.7	1.7	1.7	1.7	8.5
AER adjustment	–0.1	–0.1	–0.1	–0.1	–0.1	–0.6
Total self insurance	0.7	0.7	0.7	0.7	0.7	3.7

Note: Totals may not add due to rounding.

H.4.4 Motor vehicle risks

AER draft decision

The AER considered motor vehicle risks should be excluded from the self insurance cost category on the basis that these costs were business as usual and could thus be forecast as any other regulatory business expense. In addition, the AER considered motor vehicle risks were not wholly uncontrollable, with certain programs being able to mitigate the risks faced by a DNSP. On this basis, the AER included a self insurance allowance for motor vehicle risks of zero.[1038]

Revised regulatory proposal

ETSA Utilities confirmed the self insurance costs related to motor vehicle risks as set out in table H.7.

Table H.7: ETSA Utilities proposed motor vehicle risks self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base line	0.05	0.05	0.05	0.05	0.05	0.27
Variation	0.14	0.15	0.16	0.16	0.17	0.78
Total self insurance	0.20	0.21	0.21	0.22	0.22	1.06

Source: ETSA Utilities, *Revised regulatory proposal*, attachment G.5, p. 31.

ETSA Utilities stated it had included $0.3 million worth of self insurance costs within the risk management opex category. ETSA Utilities observed the AER had not made any adjustments to the risk management opex category in the draft decision.[1039]

ETSA Utilities agreed with the AER that motor vehicle risks are business as usual costs, as they are incurred on a regular basis and can be forecast with accuracy. ETSA Utilities stated it had classified these costs as self insurance costs within the broader

[1038] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 497–498.
[1039] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 28.

opex category and further stated that it is open for ETSA Utilities to do so. ETSA Utilities stated it is not reasonable to disallow these costs simply on the basis that they are classified as self insurance. In addition, ETSA Utilities asserted that whether a cost was classified as self insurance or as another opex category should have no impact on those costs being recognised in accordance with the NER.[1040]

ETSA Utilities considered that, given the AER's acceptance that costs associated with motor vehicle risks are a business as usual cost, there is a case for this cost to be allowed for within another cost category, such as motor vehicle operating costs. This alternative, however, was not provided by the AER nor was any adjustment made for any such allowance. ETSA Utilities thus considered that the approach adopted by the AER was inconsistent.[1041]

ETSA Utilities obtained an indicative quote to insure the deductible on its motor vehicle insurance policy. This quote indicated that it would cost ETSA Utilities in the order of between $[redacted] and $[redacted] per annum.[1042]

AER issues and considerations

The AER notes ETSA Utilities' agreement with the draft decision that motor vehicle risks are business as usual risks.[1043] The draft decision was based on the fact that a motor vehicle event is expected to happen, on average, once every two days.[1044] The AER considers that its draft decision in relation to motor vehicle risks was correct, as business as usual costs are not to be considered as uncontrollable costs, and therefore should not be classified as self insurance. As discussed in the assessment of property and poles and wires risks, this decision is consistent with the EBSS.[1045]

However, as the AER considers costs associated with motor vehicle risks are business as usual costs, the AER accepts these costs should be included in the opex allowance. The AER considers the opex allowance should compensate ETSA Utilities for losses associated with motor vehicle risks within the risk management opex category.

In addition, the AER requested ETSA Utilities remodel an error that was made in the escalation within the self insurance derivation model. ETSA Utilities advised that the correction of this error resulted in a reduction to motor vehicle risks of $0.05 million over the next regulatory control period.[1046]

Summary

The AER considers motor vehicle risks are business as usual costs, and as such should be removed from the self insurance category and accounted for within another opex category in accordance with the EBSS. These costs will be taken into account in the

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1040 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 28.
1041 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 29.
1042 ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 31 and appendix A – Indicative cost of insurance.
1043 AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 498; and ETSA Utilities, *Revised regulatory proposal*, attachment G.5, pp. 2 and 28.
1044 AON Global, *Self insurance risk quantification – ETSA Utilities*, appendix 3 – attachment 3.
1045 AER, *Final decision, Electricity DNSPs EBSS*, June 2008.
1046 ETSA Utilities, email response, AER.EU.RP.8, 26 February 2010, ETSA Issues template – No. 2.

risk management opex forecast, after being adjusted to correct the error identified in the escalation within the self insurance model.

The AER's adjustment relating to this opex category is $0.05 million reduction due to double inflation and is shown in table H.8.

Table H.8: AER conclusion on total opex allowance for motor vehicle risks ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	0.20	0.21	0.21	0.22	0.22	1.06
AER adjustment	–0.01	–0.01	–0.01	–0.01	–0.01	–0.05
Total motor vehicle risks opex allowance	0.2	0.2	0.2	0.21	0.21	1.01

Note: Totals may not add due to rounding.

H.4.5 Guaranteed Service Level Payments

AER draft decision

The AER did not accept the proposed level of self insurance for Guaranteed Service Level (GSL) payments. The AER determined GSL payments in excess of an efficient level should not be borne by customers, and that GSL payments are not an uncontrollable expense, with the extent to which GSL payments above the efficient level are paid being determined by the DNSP.[1047]

Revised regulatory proposal

ETSA Utilities noted the AER disallowed GSL payments as self insurance, while accepting the level of GSL payments as efficient when these costs were considered as part of the major opex category of network maintenance.[1048] ETSA Utilities confirmed the self insurance costs related to GSL payments as set out in table H.9.

Table H.9: ETSA Utilities proposed GSL payments self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Base line	0.8	0.8	0.8	0.8	0.8	4.1
Variation	0.5	0.5	0.5	0.5	0.5	2.6
Total self insurance	1.3	1.3	1.3	1.3	1.4	6.7

Source: ETSA Utilities, *Revised regulatory proposal*, attachment G.5, p. 36.

[1047] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 499–501.
[1048] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 31 and *Appendix A – Indicative cost of insurance*.

ETSA Utilities noted the AER's statement:[1049]

- under certain circumstances, GSL payments may be considered regulatory payments in accordance with section 2E of the NEL

- a prudent and efficient network service provider may incur GSL payments in order to meet efficient planning goals and that such payments represent a regulatory obligation imposed on ETSA Utilities

- reliability based GSL payments (that is excluding timeliness for customer appointments, connection of a new supply address and street light repair), were approximately $1.8 million in 2005–06, $0.7 million in 2006–07 and $0.4 million in 2007–08. The AER considered that ETSA Utilities forecast of GSL payments is consistent with its historical levels of GSL payments.

ETSA Utilities also noted ESCOSA had allowed ETSA Utilities to recoup GSL payments through the opex allowance in the current regulatory control period. ETSA Utilities stated the AER has accepted the GSL payments as efficient costs incurred by a prudent operator supplying standard control services.[1050]

AER issues and considerations

The AER notes ETSA Utilities' agreement with the AER's consideration that GSL payments are business as usual costs. ETSA Utilities stated:[1051]

> GSL payments at an efficient level are a business as usual cost, and may have been considered differently by the AER had it not been included within the category of self insurance.

As a business as usual cost, GSL payments are incurred on a regular basis. As such, in accordance with the EBSS, GSL payments should not be included in the uncontrollable cost category, self insurance. As such, the AER considers that the most appropriate self insurance premium for GSL payments is $0.

However, as outlined in its draft decision, the AER is cognisant of the provision in section 7A(2)(b) of the NEL which states that a DNSP must be provided a reasonable opportunity to recover the efficient costs incurred in making a regulatory payment.[1052] The AER also considered that under certain circumstances GSL payments may be considered regulatory payments.[1053]

The AER considers ETSA Utilities should be allowed to recover at least the efficient cost of making these payments. In its assessment of baseline GSL payments that were included within its opex proposal, the AER stated that:[1054]

[1049] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 31 and appendix A – Indicative cost of insurance.
[1050] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, pp. 33–34.
[1051] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 35.
[1052] AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 499–500.
[1053] AER, *Draft decision, SA draft distribution determination*, November 2009, p. 500.
[1054] AER, *Draft decision*, *SA draft distribution determination*, November 2009, p. 220.

> The AER considers that ETSA Utilities' forecast of GSL payments is consistent with its historical levels of GSL payments.

While the AER considers that ETSA Utilities should be given the opportunity to recover the efficient costs of GSL payments, the AER also considers that any amount of GSL payments made in excess of the efficient level should be borne by shareholders rather than customers. Thus the AER considers an allowance for GSL payments should be provided within the opex building block.

The AER recognises that ESCOSA permitted opex of approximately $1.2 million per annum in the current regulatory control period for GSL payments. Except for the first year of the current regulatory control period, ETSA Utilities consistently underspent its GSL payment allowance, with an average of approximately $1 million paid per annum over the current regulatory control period. When the first year of the current regulatory control period is excluded, this average becomes $0.74 million per annum. The AER considers that the forecast baseline expenditure levels are in line with historical levels of GSL payments.

However, ETSA Utilities is effectively seeking a similar allowance for GSL payments as ESCOSA approved for the current regulatory control period ($1.2 million per annum),[1055] when both the baseline and variation levels of forecast GSL expenditure are assessed. Given ETSA Utilities' consistent underspend compared to its historical GSL allowance of $1.2 million per annum, the AER considers ETSA Utilities has not justified the variation amount sought as part of the GSL allowance. The AER considers the baseline GSL amounts sought by ETSA Utilities are the efficient level of GSL payments and ETSA Utilities should be compensated for these. However, the AER considers that the amount sought in addition to this sum are inefficient GSL payments. Therefore the AER considers a reduction to ETSA Utilities' proposed total GSL allowance of $2.0 million to remove the variation amounts is necessary for the GSL payments opex allowance to reflect the opex criteria, including the opex objectives.

In addition, the AER reviewed the escalation of ETSA Utilities' self insurance costs as part of its assessment of the efficient cost of GSL payments. ETSA Utilities stated that it had made an error in its opex model by escalating GSL payments a second time, by a 'customer growth – operations' escalator. ETSA Utilities made an adjustment within its opex model to remove the effects of the second escalation. This resulted in a reduction of $0.2 million in relation to GSL payments over the next regulatory control period.[1056]

In addition, the AER requested that ETSA Utilities remodel an error that was made in the escalation within the self insurance derivation model. ETSA Utilities advised that the correction of this error resulted in a reduction to GSL payments of $0.3 million over the next regulatory control period.[1057]

[1055] ESCOSA, *ETSA Utilities 2005–2010 Electricity distribution determination*, *Part A– Statement of reasons*, April 2005, p. 100.

[1056] ETSA Utilities, email response, AER.EU.RP.8, 23 February 2010, attachment 4, p. 1.

[1057] ETSA Utilities, email response, AER.EU.RP.8, 26 February 2010, ETSA Issues template – No. 2.

Summary

The AER considers GSL payments are business as usual costs, and as such should be removed from the self insurance category and accounted for within another opex category in accordance with the EBSS. These costs will be taken into account in the risk management opex forecast. The AER's adjustments relating to this opex category are as follows:

- $2.0 million reduction to remove variation costs
- $0. 2 million reduction due to double escalation
- $0.3 million reduction due to double inflation.

The AER's decision is shown in table H.10.

Table H.10: AER conclusion on ETSA Utilities total opex allowance for GSL payments ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	1.3	1.3	1.3	1.3	1.4	6.7
AER adjustments	–0.5	–0.5	–0.5	–0.5	–0.5	–2.6
Total GSL opex allowance	0.8	0.8	0.8	0.8	0.8	4.1

Note: Totals may not add due to rounding.

H.4.6 Underground damage and environmental liability

AER draft decision

The AER did not accept the proposed self insurance allowance for underground damage. The AER rejected the proposed allowance because:

- it was concerned about providing an allowance for any activity potentially associated with illegal or unethical activity
- a lack of evidence in its regulatory proposal proving that external insurance was unavailable or providing the basis to determine an efficient premium
- the AER could not determine the incurred cost for regulatory purposes
- the AER considered that it was inappropriate to pass fines and penalties through to customers.

The AER determined in the circumstances that the most appropriate self insurance allowance for underground damage and environmental liability was zero.

Revised regulatory proposal

ETSA Utilities confirmed the self insurance costs related to underground damage and environmental liability as set out in table H.11.

Table H.11: ETSA Utilities proposed underground damage and environmental liability self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Baseline	0.4	0.4	0.4	0.4	0.4	2.1
Variation	0.1	0.1	0.1	0.2	0.2	0.8
Total self insurance	0.6	0.6	0.6	0.6	0.6	3.0

Source: ETSA Utilities, *Revised regulatory proposal*, attachment G.5, p. 42.

ETSA Utilities provided details about the incurred costs for underground damage and environmental liability. ETSA Utilities stated this cost category included activities associated with repair of underground cables used in the delivery of standard control services which, for example may have been damaged by third party actions such as a ‘directional boring’ contractor. It noted this could result in costs associated with repair to the cables and/or environmental clean up of leaked oil.[1058]

ETSA Utilities stated these costs also included costs associated with rehabilitation of ground which may have been subject to contamination by oils or fuels associated with the delivery of standard control services. ETSA Utilities stated this had occurred at depots and substations associated with its distribution network. It recognised it has been an offence to discharge a pollutant since 1993, but stated many of its sites may have been contaminated prior to that time. Further, ETSA Utilities advised there had been no environmental incidents that had breached environmental legislation or which had resulted in orders, fines or penalties imposed on it.[1059]

ETSA Utilities advised it had incorporated $2.1 million of underground damage and environmental liability costs within the risk management category of its opex proposal. ETSA Utilities observed the AER did not make any adjustments to this category in its draft decision.[1060] ETSA Utilities argued it could therefore be inferred that the AER found these costs to be efficient, and the removal of these costs through a zero self insurance allowance contradicts the opex findings in the draft decision.[1061]

ETSA Utilities refuted the argument that allowing for any underground damage and environmental liability costs may reduce the incentive to the business to prevent environmental damage. ETSA Utilities argued that the provision of an allowance should not affect the business incentive to reduce the costs where economical to do so. ETSA Utilities stated any reduction in costs it can extract from efficiencies and process changes will be carried into the efficiency carry over scheme that will benefit the customers in the future.[1062]

[1058] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 38.
[1059] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 38.
[1060] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 38.
[1061] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 38.
[1062] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 39.

ETSA Utilities stated costs related to this category are in no way related to illegal or unethical activities.[1063]

ETSA Utilities also stipulated that any costs covered in this category are net of any recoveries from contractors. However, ETSA Utilities stated, underground damage may only be discovered long after the damage was done and recovering costs from the third party may be impossible.[1064]

AER issues and considerations

The AER notes that a portion of this self insurance category is comprised of costs associated with gradual oil seepage and gradual pollution. The AER considers costs associated with gradual seepage and pollution may be incurred in the past provision of services, rather than standard control services to be provided in the next regulatory control period. In effect, if ETSA Utilities were given an allowance to cover these costs, current and future customers may be paying for costs that were incurred in the provision of services in the past. The AER does not consider that costs associated with underground damage and environmental liability incidents that occurred in the past (but the full consequences of which have not yet been realised) should be passed onto current or future users. Nor does the AER consider that these costs relate to the provision of standard control services in the next regulatory control period. These represent contingent liabilities which the AER considers should be borne by the DNSPs' shareholders.

The fact that the DNSP, or a previous owner of the DNSP's assets, may not have had measures in place in the past to manage the risk is no reason for current or future users to bear the consequences of past underground damage and environmental liability events. The regulatory framework is forward–looking with the objective of adequately compensating the DNSPs for efficient costs and risks incurred over the regulatory control period.

It is difficult to assess whether damage done to the network some time ago was prudently and efficiently investigated or managed before and at the time of the incident. The AER cannot be satisfied that the DNSP, or a previous operator, acted in a prudent and efficient manner when the damage occurred. Neither can the AER be satisfied that the costs incurred reflect the costs of a prudent and efficient operator. The AER does not consider that such costs should be paid by customers, even when such damage may have been caused by imprudence or inefficiencies by a previous operator.

The AER also considers a DNSP may be able to recoup environmental liability costs at a later stage. If, for example, ETSA Utilities was required to clean up or rehabilitate a particular site before sale, it would be reasonable to expect that the value of the funds expended in relation to the clean up would be reflected in the sale price by a prudent and efficient business. The AER therefore considers it inappropriate to pass these costs onto customers, and considers that a DNSP should not be compensated for environmental liability and clean up costs within the opex allowance.

[1063] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 39.
[1064] ETSA Utilities, *Revised regulatory proposal*, January 2010, attachment G.5, p. 40.

The AER accepts that underground damage costs are an acceptable business cost. This is because the repair of underground lines to bring them back into a serviceable condition is directly related to the provision of standard control services during the next regulatory control period. However, when the AER requested a breakdown of costs to illustrate which costs were related to the repair of underground damage and which costs were related to the clean up costs or rehabilitation costs as a result of underground damage, ETSA Utilities stated that it was unable to provide a split between these two aspects.[1065] As such, the AER was unable to determine the respective amounts related to repairs and clean up or rehabilitation costs associated with underground damage. The AER therefore considers that the most appropriate self insurance premium for underground damage and environmental liability is $0.

Summary

The AER does not consider that environmental liability costs should be self insured or recouped through another element of the building blocks for the following reasons:

- costs associated with past events should not be paid for by current and future users
- environmental liability costs do not relate to the provision of standard control services in the next regulatory control period
- it is difficult to assess the prudence and efficiency of business actions when an event may have occurred some time ago
- costs expended in relation to site rehabilitation should be subsequently reflected in the value of land upon which the funds were spent.

The AER accepts costs associated with underground damage are an acceptable business cost for regulatory purposes and may be self insured. However, ETSA Utilities was not able to produce sufficient information to outline the costs associated strictly with repair costs as a result of underground damage. The AER therefore considers that the most appropriate self insurance allowance for underground damage and environmental liability is $0.

The AER's decision is shown in table H.12.

Table H.12: AER conclusion on ETSA Utilities' self insurance allowance for underground damage and environmental liability ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	0.6	0.6	0.6	0.6	0.6	3.0
AER adjustment	–0.6	–0.6	–0.6	–0.6	–0.6	–3.0
Total self insurance	0	0	0	0	0	0

Note: Totals may not add due to rounding.

[1065] ETSA Utilities, email response, Self insurance questions, 14 April 2010.

H.4.7 Worker's compensation

AER draft decision

The AER accepted ETSA Utilities' self insurance proposal for worker's compensation events, on the basis that worker's compensation was an unavoidable business expense for the electricity distribution industry. In addition, ETSA Utilities' subsidiary, Utilities Management Pty Ltd, is registered as a worker's compensation self insurer with WorkCover SA.

Revised regulatory proposal

ETSA Utilities accepted the draft decision in respect of self insurance for worker's compensation.[1066] ETSA Utilities confirmed the self insurance costs for worker's compensation as shown in table H.13.

Table H.13: ETSA Utilities proposed worker's compensation self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	0.4	0.4	0.4	0.4	0.4	1.9
Variation	0.2	0.2	0.2	0.2	0.2	1.0
Total self insurance	0.5	0.6	0.6	0.6	0.6	2.9

Source: ETSA Utilities, *Revised regulatory proposal*, Attachment G.5, p. 44.

AER issues and considerations

The AER reviewed the escalations applied by ETSA Utilities both within the self insurance derivation spreadsheet and within the opex model as part of the process to determine the efficient premium. ETSA Utilities made an adjustment to remove the impact of the double escalation. This resulted in a reduction of $0.4 million over the next regulatory control period.[1067]

The AER also requested that ETSA Utilities remodel an error that was made in the self insurance derivation model. ETSA Utilities advised that the correction of this error resulted in a reduction to underground damage and environmental liability of $0.1 million over the next regulatory control period.[1068]

Summary

The AER considers ETSA Utilities self insurance allowance for workers compensation, after correction for errors, represents an efficient opex allowance.

The AER's adjustments relating to this opex category is a $0.1 million reduction due to double inflation. The AER's decision is shown in table H.14.

[1066] ETSA Utilities, *Revised regulatory proposal*, January 2010, Attachment G.5, p. 44–45.
[1067] ETSA Utilities, email response, AER.EU.RP.8, 23 February 2010, p. 2.
[1068] ETSA Utilities, email response, AER.EU.RP.8, 26 February 2010, ETSA Issues template – No. 2.

Table H.14: AER conclusion on ETSA Utilities proposed worker's compensation self insurance allowance ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	0.5	0.6	0.6	0.6	0.6	2.9
AER adjustment	–0.1	–0.1	–0.1	–0.1	–0.1	–0.5
Total self insurance	0.5	0.5	0.5	0.5	0.5	2.4

Note: Totals may not add due to rounding.

H.5 Reporting requirements

In relation reporting requirements, the AER largely confirms its draft decision. The AER considers that self insurance events should be reported as contingent liabilities, in accordance with Australian Accounting Standards Board (AASB) standard 137. The AER notes ETSA Utilities did not make any comment on the reporting arrangements in relation to self insurance, as outlined in the draft decision.

However, in response to concerns raised by Energex,[1069] the AER reviewed its position on the reporting arrangements for self insurance. The AER considers that any recurrent, low cost events should be included within a DNSPs controllable opex forecast, and thus any reporting related to self insurance would only be for relatively infrequent, high cost events. This includes liability claims, where the AER has reclassified recurrent low value liability claims as controllable opex. These claims would be reported as an opex category as part of ETSA Utilities' annual reporting requirements. Only large and fire liability claims would be required to be reported in the manner outlined in appendix K.

The AER, in having regard to Energex's concerns, now considers that reporting of self insurance events, as outlined in appendix K of this decision, should be undertaken annually as part of the annual reporting requirements of the DNSPs. However, the AER confirms that the form of reporting should be as outlined within the draft decision, and reiterated in appendix K of this decision.

H.6 AER conclusion

For the reasons discussed in section H.4 and as a result of the AER's consideration of ETSA Utilities' regulatory proposal and revised regulatory proposal, submissions and other material, the AER is not satisfied that ETSA Utilities' self insurance forecast reasonably reflects the opex criteria, including the opex objectives. The AER considers that reducing ETSA Utilities' self insurance forecast by $29.9 million results in expenditures that reasonably reflect 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.

[1069] Energex, *Submission on the draft determination*, February 2010, p. 28.

While the AER has rejected several proposed events as self insurance events, the AER accepts ETSA Utilities should be compensated for some of these events in accordance with the NER. Consequently, the AER has rejected the events as self insurance events but allowed for these costs of $21.6 million ($2009–10) within ETSA Utilities' controllable opex forecasts.

The AER requested ETSA Utilities to remodel its self insurance opex forecast to reflect the AER's decision, in addition to the AER's decision on input cost escalation. ETSA Utilities provided an updated self insurance premium forecast of $6.1 million for the next regulatory control period.[1070]

Table H.15 summarises ETSA Utilities' proposed self insurance allowance and the AER's decision, excluding the effects of real input cost escalation.

Table H.15: AER conclusion on self insurance allowance for ETSA Utilities ($m, 2009–10)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
ETSA Utilities	6.9	7.1	7.2	7.3	7.5	36.0
AER adjustments	–1.5	–1.6	–1.7	–1.7	–1.8	–8.3
Less controllable opex excluded from self insurance	4.3	4.3	4.3	4.3	4.4	21.6
Total self insurance	1.2	1.2	1.2	1.2	1.3	6.1

Note: Totals may not add due to rounding.

[1070] ETSA Utilities, email response to AER modelling request, 14 April 2010.

I. Benchmarking

Benchmarking can be defined as a process of comparison of some measure of actual performance against a reference or benchmark.[1071] 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).

I.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:[1072]

> (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:[1073]

> (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:[1074]

> (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.

[1071] 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.
[1072] NER, clause 6.5.6(a).
[1073] NER, clause 6.5.6(c).
[1074] NER, clause 6.5.6(e).

I.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:[1075]

- 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[1076] 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.[1077] 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.

[1075] AER, internal analysis.
[1076] 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.
[1077] 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.[1078] 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.[1079] This analysis was informed by benchmarking work that has been undertaken by Ofgem in the United Kingdom, and by Wilson Cook for the AER.[1080] 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.

1078 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.

1079 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.

1080 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.[1081]

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.[1082] The model also does not take into account any capex/opex tradeoffs.[1083] 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.[1084]

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.[1085] 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.[1086] 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.[1087]

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.[1088] 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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[1081] Wooldridge, J. M., *Introductory Econometrics*, 4th Edition, 2009, pp. 96–99.
[1082] Wooldridge, J. M., *Introductory Econometrics*, 4th Edition, 2009, p. 677.
[1083] More discussion of this can be found below.
[1084] AER, *Draft decision, Queensland draft distribution determination*, November 2009, appendix I, pp. 624–625 and pp. 659–660.
[1085] The AER's analysis of Ergon Energy in this instance compared Ergon Energy only to other DNSPs operating in a regional environment.
[1086] 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.
[1087] Subject to the limitations as discussed in this appendix.
[1088] 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.

I.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'.[1089] 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.[1090] It also stated that the benchmarking in relation to opex was inadequate as the AER:[1091]

- 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.[1092] The EUAA also estimated a reduction of 27 per cent of ETSA Utilities' average annual revenue allowed in the draft decision.[1093]

Cement Australia stated that it was concerned that the AER use benchmarking to help establish an efficient level of networking costs.[1094]

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

[1089] ECCSA, *A response*, February 2010, p. 29.
[1090] EUAA, *Submission to the AER on QLD DNSPs*, February 2010, p. 19.
[1091] EUAA, *Submission to the AER*, February 2010, p. 25
[1092] EUAA, *Submission to the AER*, February 2010, p. 28.
[1093] EUAA, *Submission to the AER*, February 2010, p. 29.
[1094] 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.[1095]

I.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.[1096]

- Huegin Consulting Group (Huegin) reviewed certain aspects of the AER's benchmarking analysis. Huegin took issue with:[1097]

  - 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.

I.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.[1098] While the AER must have regard to the benchmark expenditure that would be incurred by an efficient DNSP over the

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1095 EnergyAustralia, *EnergyAustralia submission on AER draft determinations for Queensland and South Australia*, 16 February 2010, pp. 1–5.

1096 Benchmark Economics, *Ergon Energy Review of Benchmarking: AER review of capital and operating expenditure forecasts*, December 2009, pp. 1–27.

1097 Huegin Consulting Group, *Review of Qld draft determination and Parsons Brickerhoff report on Ergon Energy's regulatory proposal*, January 2010, pp. 69–73.

1098 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.[1099] This issue is also touched on in the Benchmark Economics report provided by Ergon Energy.[1100] 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.[1101] 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.[1102]

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.

[1099] EUAA, *Submission to the AER on QLD DNSPs*, February 2010, p. 26.

[1100] Benchmark Economics, *Ergon Energy Review of Benchmarking: AER review of capital and operating expenditure forecasts*, December 2009, pp. 19–20.

[1101] 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.

[1102] 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.[1103] 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.[1104]

The EUAA further submitted that a line of best fit obtained by OLS regression should not qualify as an efficiency frontier.[1105] 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

[1103] EUAA, *Benchmarking and AER electricity network determinations: appendix*, January 2010, p. 3.
[1104] Gujarati, D.N., *Essentials of Econometrics*, Third Edition, 2006, pp. 149–150
[1105] EUAA, *Benchmarking and AER electricity network determinations: appendix*, January 2010, p. 3.

combined scale variable ('size').[1106] 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.[1107]

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.[1108] 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.[1109] 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).[1110] 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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[1106] 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.

[1107] 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.

[1108] Benchmark Economics, *Ergon Energy Review of Benchmarking: AER review of capital and operating expenditure forecasts*, December 2009, p. 8.

[1109] Benchmark Economics, *Ergon Energy Review of Benchmarking: AER review of capital and operating expenditure forecasts*, December 2009, pp. 14–16.

[1110] 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.[1111] 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.[1112] 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.[1113] 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.[1114] 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.

[1111] EUAA, *Benchmarking and AER electricity network determinations: appendix*, January 2010, p. 1.

[1112] Shuttleworth, G, Benchmarking of electricity networks: Practical problems with its use for regulation, *Utilities Policy 13*, 2005, p. 311.

[1113] As a result of differing business circumstances and having developed under differing regulatory regimes, DNSPs currently have varied cost allocation and accounting policies.

[1114] 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.[1115]

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.[1116] 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.[1117] 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.[1118] The quality of service could also be treated as an output, in order to capture the trade–off between service reliability and cost.[1119]

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.[1120]

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.

1115 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.

1116 Shuttleworth, G, Benchmarking of electricity networks: Practical problems with its use for regulation, *Utilities Policy 13*, 2005, p. 312.

1117 AER, internal analysis.

1118 This depends on the cost elasticity of demand management.

1119 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.

1120 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.[1121] 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.[1122] 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.[1123]

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.

[1121] 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.

[1122] 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.

[1123] Shuttleworth, G, Benchmarking of electricity networks: Practical problems with its use for regulation, *Utilities Policy 13*, 2005, p. 317.

I.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.

J. Debt raising costs for completion method

This appendix sets out the AER's consideration of debt raising costs associated with the completion method.

AER draft decision

The AER did not consider that the costs of the completion method represented efficient costs incurred by a benchmark DNSP. Accordingly, the AER did not provide an allowance associated with the completion method in respect of ETSA Utilities' claim for debt raising costs.[1124] The AER's principal concern with this argument was that it presumed that the circumstances of a specific firm (ETSA Utilities) defined the benchmark firm. The AER also noted that Standard and Poor's indicated that a firm without an implemented refinancing plan (three months ahead of the maturity date) may be evaluated, but there is no automatic downgrade.[1125]

Revised regulatory proposal

ETSA Utilities did not accept the draft decision, which provided no allowance for debt raising costs associated with the completion method.[1126] ETSA Utilities repeated its proposal for an allowance, based upon a unit rate of 11.2 basis points per annum (bppa), calculated in the same way as the standard debt raising costs.[1127] Although no additional evidence to support these costs was provided, ETSA Utilities indicated it would submit a consultant report in late January 2010.[1128]

Submissions

On 16 February 2010 ETSA Utilities submitted a report from PricewaterhouseCoopers (PwC) to support its claim for debt raising costs associated with the completion method.[1129] The AER notes that 16 February 2010 was the closing day for submissions and as a consequence interested parties have not had the opportunity to be consulted on this report.

PwC estimated the likely costs to be incurred by a benchmark service provider under three scenarios:[1130]

- the completion method—the refinancing transaction was wholly executed three months prior to the date it was required
- the commitment method—contracts to commit parties to the refinancing were signed three months prior to the date of the actual funds transfer

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1124 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 238–239.
1125 AER, *Draft decision, SA draft distribution determination*, November 2009, pp. 576–577, (confidential Appendix K).
1126 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 130.
1127 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 130.
1128 ETSA Utilities, *Revised regulatory proposal*, January 2010, p. 131.
1129 ETSA Utilities, *Re: Benchmarking debt raising costs associated with the completion method*, 16 February 2010, and PwC, *ETSA Utilities: Distribution network service provider refinancing costs: Final report*, 15 February 2010 (PwC, *DNSP refinancing costs*, February 2010).
1130 PwC, *DNSP refinancing costs*, February 2010, pp. 8–9.

- the underwriting method—three months prior to the refinancing, the service provider engages a third party to underwrite the issuance of bonds.

PwC concluded that the completion method results in the lowest cost to the service provider and is common practice in financial markets.[1131]

Consultant review

AER engaged Associate Professor John Handley to review ETSA Utilities' revised regulatory proposal and the PwC report.

Handley found that there were conceptual grounds to support the claim for debt raising costs associated with the completion method:[1132]

- refinancing costs have already been referred to by the AER as a legitimate expense for which a DNSP should be provided an efficient allowance
- it is prudent for a benchmark DNSP to have a refinancing plan—that is, a plan to eliminate refinancing risk, which may incorporate one of the completion, commitment or underwriting methods identified by PwC
- the set of comparator firms that inform the benchmark do use refinancing plans, including observed use of the completion method.

However, Handley stated that there were practical difficulties with implementing the allowance proposed by PwC:[1133]

- there may be overlap between the current allowance for standard debt raising costs and the new proposal
- in particular, the current allowance for standard debt raising costs already includes an underwriting component, and the underwriting method is a direct alternative to the completion method
- the inclusion of a credit margin premium—effectively underpricing of the debt—would be double counting, since this was already included in appropriate estimates of the cost of debt
- the time value of money was not consistently handled.

Handley noted that although a DNSP may adopt different arrangements, the allowance approved by the AER would be based on the efficient costs incurred by a benchmark DNSP, which would be the lowest cost option available.[1134]

1131 PwC, *DNSP refinancing costs*, February 2010, p. 5.
1132 Handley, *A note on the completion method, Report prepared for the Australian Energy Regulator, Final version*, 13 April 2010, pp. 6–8 (Handley, *Note on the completion method*, April 2010).
1133 Handley, *Note on the completion method*, April 2010, pp. 9–11.
1134 Handley, *Note on the completion method*, April 2010, p. 8.

AER considerations

Framework for assessment

The AER noted in the draft decision that the evaluation of completion method costs should be in the context of the benchmark firm. The current allowance for (standard) debt raising costs is based upon a benchmark analysis conducted by the Allen Consulting Group (ACG) in 2004.[1135] The AER considers that ETSA Utilities' submission, incorporating the PwC report, addresses the need to assess benchmark costs.[1136]

The benchmark firm is a theoretical concept, and the AER acknowledges that it is unlikely that a real world firm will exactly match the benchmark. In this case, the AER establishes a comparator set, comprised of businesses that closely resemble the theoretical benchmark—that is, the benchmark is informed by the observed actions of the comparator set.[1137] This was stated by ACG:[1138]

> The objective for the financing structure benchmark is often described as the financing arrangements into which an efficiently financed entity would enter. However, as both the theoretical and measurement difficulties preclude the derivation of the 'efficient' financing arrangements, the benchmarks adopted in practice typically reflect observations of standard industry practice.

The opex of the benchmark firm is assessed with regard to prudence, as required by clause 6.5.6 of the NER. The AER considers that if the close comparators to the benchmark firm are observed to undertake a particular action, this supports the conclusion that such an action is prudent. The AER notes that Handley made a similar assessment.[1139]

A cornerstone of incentive regulation is that a particular DNSP does not have to follow the behaviour of the theoretical benchmark firm. The DNSP is free to adopt an alternative approach, accepting the benefits or detriments that arise as a consequence of deviation from the benchmark. This was summarised by ACG:[1140]

> A key objective of setting regulated prices based upon benchmarks for financing structure — rather than based upon actual financing arrangements and costs — is to provide the businesses with an incentive to adopt efficient financing arrangements. In particular, the businesses retain the benefits from adopting more efficient financing arrangements than assumed by the regulator, and customers are protected if regulated entities are inefficient in their financing decisions.

Key issues

The AER notes that:

1135 ACG, *Final report, Debt and equity raising transaction costs, Report to the Australian Competition and Consumer Commission*, December 2004, p. vii (ACG*, Debt and equity raising costs*, December 2004).

1136 PwC, *DNSP refinancing costs* February 2010, p. 7.

1137 AER, *Final decision, WACC parameters*, May 2009, pp. 79–82, 101–110.

1138 ACG, *Debt and equity raising costs*, December 2004, p. vii.

1139 Handley, *Note on the completion method*, April 2010, pp. 7–8.

1140 ACG, *Debt and equity raising costs*, December 2004, p. 3.

- The overarching purpose of the three approaches included in the PwC report—the completion method, the commitment method and the underwriting method—is to reduce refinancing risk. This is defined by ETSA Utilities as:[1141]

> Refinancing risk is the risk that replacement finance will not be available when debts fall due for repayment, thus leading to default.

- The three approaches are proposed by ETSA Utilities as competing alternatives, so (at most) only one of the three would be required.[1142] ETSA Utilities sought an allowance for debt raising costs associated with the completion method on the grounds that this method entails the lowest cost of the three.[1143]

- The proposal for costs associated with the completion method is in addition to the (standard) debt raising costs estimated by the AER on the basis of the ACG methodology.[1144]

Based on the above, the AER considers that there are three interrelated assessments that need to be made:

a. To what extent should the benchmark firm act to reduce refinancing risk?

b. Which of three alternative methods is the most efficient means to reduce refinancing risk—that is, to the extent required by (a)?

c. Does the current allowance for (standard) debt raising costs already encompass the appropriate actions to reduce refinancing risk—that is, use of the most efficient method in accordance with (b) to the extent required by (a)?

Validity of a refinancing plan

The AER considers that it is prudent for the benchmark firm to manage refinancing risk. The benchmark firm maintains an investment-grade credit rating (BBB+), and therefore should meet the requirements of credit rating agencies such as Standard and Poor's for a firm of this credit rating. These requirements are detailed in a Standard and Poor's statement provided by ETSA Utilities in its regulatory proposal:[1145]

> For the Australian investment-grade corporates, we expect to see a measured and logical approach to meet upcoming debt maturities. We would want to see that the company has a credible strategy for repaying or refinancing debt maturing up to 18 months ahead. As maturities move into the forward 12–month time horizon, we will start placing more weight within the short-term rating analysis on the materiality of upcoming maturities and the company's refinancing strategy and execution ability.

[1141] ETSA Utilities, *Regulatory proposal, Attachment F.14: CFO declaration regarding debt raising costs and supporting information*, confidential, 1 July 2009, p. 2.

[1142] ETSA Utilities, *Regulatory proposal, Attachment F.14: CFO declaration regarding debt raising costs and supporting information*, confidential, 1 July 2009, pp. 2–7.

[1143] ETSA Utilities, *Re: Benchmarking debt raising costs associated with the completion method*, 16 February 2010, p. 2.

[1144] ETSA Utilities, *Regulatory proposal*, July 2009, p. 155 and ETSA Utilities, *Revised regulatory proposal*, January 2010, pp. 130–131.

[1145] Standard and Poor's, 'Refinancing and liquidity risks remain, but Australia's rated corporates are set to clear the debt logjam', *RatingsDirect*, 22 April 2008, p. 7.

The AER considers the benchmark firm will manage its refinancing risk through a refinancing plan. The AER notes that Handley concurred with this assessment:[1146]

> It is prudent for a DNSP to implement a refinancing plan in advance of when the debt falls due (in order to reduce refinancing risk).

The AER considers that the refinancing plan will set out a timeline for actions by the firm to ensure that it does not default on its debt, and so may include use of the completion, commitment or underwriting methods. Consistent with the description above from Standard and Poor's,[1147] the AER notes that the refinancing plan is not limited to the three specific methods investigated by PwC but encompasses a broader range of actions by the firm. Standard and Poor's also stated:[1148]

> Prudent liquidity and liability management by corporates means having sufficient cash to cover near-term maturities or a refinancing plan that we view as having little execution risk, such as planned market access with committed credit facilities as a back up.

The AER considers that the refinancing plan may also include management of maturity dates, cash reserves and other credit facilities (such as a working capital account) to reduce refinancing risk.

A refinancing plan is not a new requirement

The AER notes that ETSA Utilities suggested the completion method was required as a consequence of the global financial crisis (GFC) changing the requirements of credit rating agencies:[1149]

> It should also be noted that in the current economic climate, the S&P rating requirements for refinancing of an impending debt maturity to be completed, committed or underwritten at least 3 months prior to its maturity date means that credit ratings agencies (such as S&P) are exerting a higher degree of rigour in monitoring such requirements than would otherwise be the case.

However, the AER considers that the requirement to manage refinancing risk did not arise with the GFC but has been a long-term fundamental requirement for the benchmark firm. This is supported by Standard and Poor's, where it noted:[1150]

> Liquidity and liability management have always been key components of our rating methodology and their importance within credit analysis have been borne out in the current credit market conditions.

PwC made a similar comment:[1151]

[1146] Handley, *Note on the completion method*, April 2010, p. 7.

[1147] Standard and Poor's, 'Refinancing and liquidity risks remain, but Australia's rated corporates are set to clear the debt logjam', *RatingsDirect*, 22 April 2008, p. 7.

[1148] Standard and Poor's, 'Refinancing and liquidity risks remain, but Australia's rated corporates are set to clear the debt logjam', *RatingsDirect*, 22 April 2008, p. 6.

[1149] ETSA Utilities, *Regulatory proposal, Attachment F.14: CFO declaration regarding debt raising costs and supporting information*, confidential, 1 July 2009, p. 2. See also ETSA Utilities, *Regulatory proposal*, July 2009, p. 155.

[1150] Standard and Poor's, 'Refinancing and liquidity risks remain, but Australia's rated corporates are set to clear the debt logjam', *RatingsDirect*, 22 April 2008, p. 6.

> Although the mitigation of refinancing risk has been heightened by the Global Financial Crisis, refinancing risk has always been a major focus for borrowers.

Similarly, Handley noted:[1152]

> Whilst recent events in world credit markets have arguably drawn more attention to the issue of refinancing risk, in my view, the prudence of an appropriate refinancing plan was well accepted before then and will continue to remain thereafter.

The AER notes that the Standard and Poor's document provided by ETSA Utilities is exclusively concerned with 2008 market conditions.[1153] Although it may be indicative of tighter conditions at the time—during the worst of the GFC—there has been no evidence presented to suggest that these conditions would apply across the regulatory control period. Rather, statements from Australian and international economic authorities support the conclusion that more normal market conditions will exist from 1 July 2010 to 30 June 2015.[1154]

The AER therefore considers that there is no qualitative difference between the refinancing plans required by the benchmark firm in earlier regulatory control periods and the current need for a refinancing plan.

Limits on the refinancing plan

The AER considers that there will be limits on the extent to which the benchmark firm acts to manage refinancing risk. From a theoretical perspective, there will be a point where the marginal cost to further reduce refinancing risk outweighs the marginal benefit of doing so.

The AER notes that there is a possibility to trade-off debt raising costs against the cost of debt. Actions that increase the credit rating of a bond issue may increase the transaction costs of raising debt, but consequently decrease the interest costs that must be paid by the DNSP.[1155] The AER will only allow the efficient costs for the benchmark firm to take the minimum actions required to maintain the benchmark credit rating. This is consistent with Handley's advice:[1156]

> In this regard, it is noted that efficient is usually taken to mean least cost (and which relate to action which maintain, but not improve, the benchmark credit rating).

Evaluating the three PwC approaches

The PwC report presents the benchmark costs of three approaches to reduce refinancing risk: the completion method, the commitment method, and the underwriting method.

1151 PwC, *DNSP refinancing costs*, February 2010, p. 23.
1152 Handley, *Note on the completion method,* April 2010, pp. 7–8 (and footnote 11).
1153 Standard and Poor's, 'Refinancing and liquidity risks remain, but Australia's rated corporates are set to clear the debt logjam', *RatingsDirect*, 22 April 2008, pp. 2–7.
1154 RBA, *Minutes of the Monetary Policy Meeting of the Reserve Bank Board,* 2 March 2010.
1155 As an example, consider credit wrapping, which is assessed in ACG, Debt and equity raising costs, December 2004, pp. xix–xx.
1156 Handley, *Note on the completion method,* April 2010, p. 8.

The completion method

The completion method—executing the refinancing transaction three months prior to the date it is required—was costed by PwC at between 20 and 24 bppa.[1157] Handley stated:[1158]

> … the PwC approach to estimating the cash cost of the Completion Method (of about $1.3 million) is reasonable.

The AER notes that there was some inconsistency when converting up-front costs (130 basis points) to annual unit rates:

- ETSA Utilities simply divided the up-front cost by 10 years to estimate a cost of 13 bppa[1159]
- PwC amortised the up-front costs using the cost of debt, and estimated a cost of 20 to 24 bppa.

The AER considers that the preferred approach is to adjust for the time value of money by discounting annual payments. In the context of the PTRM, this discount rate should be the nominal vanilla WACC, not the cost of debt as implemented by PwC.[1160]

The AER also notes that the cost of the completion method arises from the differing interest rates applying to funds borrowed and funds lent. This is directly linked to the size of the debt risk premium, and the term spread between 10 year and 3 month Commonwealth government securities. In both cases, current values have significantly changed from those in the PwC report. These values are presented in table J.1.

[1157] PwC, *DNSP refinancing costs*, February 2010, p. 5.

[1158] Handley, *Note on the completion method*, April 2010, p. 10.

[1159] Although ETSA Utilities interpreted PwC's calculation as supporting a unit rate of 13 bppa, its revised regulatory proposal is only for 11.2 bppa, which is consistent with the figure from its regulatory proposal.

[1160] Discounting debt-related cashflow at the cost of debt would be appropriate if all payment streams were discounted according to their individual level of risk—for instance, discounting equity-related cashflow at the cost of equity. The PTRM does not do this, adopting the simpler (but conceptually sound) approach of discounting all cashflow at the WACC.

Table J.1: Cost of the completion method using updated data

Item	15 December 2009 (PwC report)	29 March to 23 April 2010 (averaging period)
Risk-free rate (10 year CGS) (%)	5.40	5.65
Debt risk premium (%)	4.29	3.33
Interest rate on funds borrowed (%)	**9.69**	**8.98**
3-month government treasury notes (%)	3.70	4.15
BBSW margin above treasury notes (%)[a]	0.5–0.0	0.5–0.0
BBB+ margin above BBSW(%)[b]	0.5–0.0	0.5–0.0
Interest rate on funds lent (%)	4.70–3.70	4.70–3.70
Difference in interest rates	**4.99–5.99**	**3.83–4.83**
Up-front cost (basis points)	125–150	96–121
Discount rate (%)	9.69	9.72
Unit rate (bppa)	**20–24**	**15–19**

Source: PwC, *DNSP refinancing costs*, February 2010, pp. 12, 14–15; RBA, *Interest Rates and Yields – Money Market – Daily –F1* and *Indicative Mid Rates of Commonwealth Government Securities – 2009 to Current – F16*, available at www.rba.gov.au/statistics/tables, accessed 26 April 2010; AER analysis.

Note: The agreed averaging period is based on the period set out in chapter 11.

(a) The PwC report modelled both investments in treasury bills and in bank deposits

(b) This margin is applied where bonds are redeemed early, which PwC modelled at varying take up rates between 0 and 100 per cent.

After adjusting for current market data and accommodating the time value of money, the AER considers that the costs of the completion method are in the range of 15 to 19 bppa.

The commitment method

The commitment method—signing contracts to commit parties to the refinancing three months prior to the date of the actual funds transfer—is costed by PwC at between 22 and 24 bppa.[1161]

The AER does not consider that PwC has correctly calculated the cost of the commitment method. In particular, PwC included an opportunity cost for the bond buyer:[1162]

> The opportunity cost over a 3 month period of receiving the agreed yield on the bond immediately after committing to purchase the bond…

[1161] PwC, *DNSP refinancing costs*, February 2010, p. 5.
[1162] PwC, *DNSP refinancing costs*, February 2010, p. 16.

The AER acknowledges that estimation of opportunity costs inevitably involves assumptions about agent preferences. However, PwC assumed a scenario where the investor would prefer to purchase a bond immediately, and must be compensated for the delay between commitment and execution. This ignores the scenario where the investor would prefer to purchase the bond in three months time, and wants certainty in advance that such a purchase can be made. It is not controversial to note that lenders, as well as borrowers, desire certainty in advance for their investment. Indeed, this is implicitly stated elsewhere by PwC:[1163]

> All else being equal, most fixed interest investors would prefer to hold the bond to maturity than to accept a buy-back proposal. Accepting a buy-back would result in the investor receiving cash ahead of expectations, therefore requiring the investor to quickly find reinvestment opportunities for the cash.

Under such a scenario, there is no opportunity cost for the investor. The commitment method is beneficial for both buyer and seller of the bond, and the benchmark firm would not have to compensate the investor in the manner suggested by PwC.

PwC stated that commitments longer than a few days are practically non-existent, and that no parties want advance binding commitment of this type.[1164] The AER considers that this does not appear reasonable because it ignores the fact that most bond issues undertaken by the benchmark firm are to retire existing debt. That is, there is an existing bond that will expire, so a new bond is being issued for the same amount. Relevantly, PwC stated:[1165]

> The majority of investors are expected to be fixed interest managers whose mandate requires them to hold bonds and as a result would have an aversion to hold cash received from a buy-back.

These same fixed interest managers will be averse to holding cash at maturity, and will seek opportunities to buy bonds at that time. The commitment approach is therefore likely to be desirable for such investors, since they can lock in the new bond in advance, effectively rolling over their investment with little risk.

The extent to which opportunity costs will be reduced via this mechanism will depend on the proportion of bond buyers who prefer to invest in three months time. Although this proportion is not known, the AER considers that it is unreasonable for PwC to assume that no transactions of this type occur. Nonetheless, the AER models the maximum possible range of opportunity cost (that is, between zero and one hundred per cent). Table J.2 presents the AER’s revised calculation of commitment method costs, including updated market data.

1163 PwC, *DNSP refinancing costs*, February 2010, p. 11.
1164 PwC, *DNSP refinancing costs*, February 2010, pp. 16–17.
1165 PwC, *DNSP refinancing costs*, February 2010, p. 13.

Table J.2: Costs of the commitment method using updated data

Item	15 December 2009 (PwC report)	29 March to 23 April 2010 (averaging period)
Cost of the completion method (bppa)	22–24[a]	15–19
Opportunity cost (as a proportion of completion method costs)	100%	0–100%
Unit rate (bppa)	**22–24**	**0–19**

Source: PwC, *DNSP refinancing costs*, February 2010, pp. 17–18 and AER analysis.
(a) Although PwC estimated the cost of the commitment method based on the costs of the completion method, it does not include the lower half of the commitment method range (from 20 to 22 bppa).

After adjusting for current market data, accommodating the time value of money, and allowing for plausible variation in the opportunity cost, the AER considers that the costs of the commitment method are in the range of 0 to 19 bppa.

The underwriting approach

The underwriting method—engaging a third party to underwrite the transaction, three months prior to the refinancing date—is costed by PwC at between 46 and 54 bppa.

The AER does not consider that PwC has appropriately costed the underwriting method. There are different underwriting options detailed by PwC, including:[1166]

> Underwriters would mitigate these risk through a combination of:
> …
> Underwrite the volume only, rather than volume and price. Under such scenario, the underwriter may incorporate a “market flex” provision in the pricing of the bond, providing the underwriter the flexibility to increase the yield/credit margin of the bond until sufficient bids are received from investors to complete 100% sale of the bonds.

The AER considers that this type of underwriting is appropriate for the benchmark firm. The cost of debt for the benchmark firm is set during the agreed averaging period. Three months in advance of the averaging period, the benchmark firm would enter a contract with the underwriter to issue the debt during the averaging period. The benchmark firm does not need to lock in a price at this point, since it knows that whatever movements occur in the cost of debt, it will be compensated for. Hence, it is able to enter an underwriting contract to sell at the prevailing price in the averaging period, whatever that may be.

The advantage for the benchmark firm is that this type of underwriting is far cheaper, as PwC stated:

> For an underwriting that incorporates volume underwriting only, our cost estimate is that an underwriting fee of 25 bps to 50 bps would apply.[1167]

[1166] PwC, *DNSP refinancing costs*, 15 February 2010, p. 19.
[1167] PwC, *DNSP refinancing costs*, February 2010, p. 20.

Amortised at the allowed nominal vanilla WACC, the underwriting cost is 4 to 8 bppa.

Further, even if the firm was to engage in underwriting on volume and price, the AER considers that the cost calculation by PwC is overstated. PwC stated:[1168]

> Underwriters would mitigate these risk through a combination of:
> …
> Require the underwritten price (i.e. credit margin) to be at premium to where benchmark issuers/credits would normally be expected to price comparable bond transactions. The premium would be required to provide the bank comfort that it would be able to successfully sell all the bonds.

PwC estimated that this credit margin premium would be between 30 and 50 bppa. Handley noted:[1169]

> However, it appears that this credit margin premium may in effect represent underpricing of the new debt. As discussed in an earlier report, assuming allowed revenues are determined using an appropriate estimate of the cost of debt then it is my view that, underpricing should not be allowed as a (direct) cost of raising debt capital (otherwise double counting would result).

The AER notes that extensive prior analysis of empirical evidence found that the market based methodology used to set the debt risk premium prices the cost of debt such that there is no requirement to add an underpricing allowance.[1170] Since management of refinancing risk is not a new requirement, it would be reasonable to assume that the credit margin premium described by PwC has been encapsulated in this empirical data. This leads to the underwriting method costs reported in table J.3.

Table J.3: Cost of the underwriting method using updated data

Item	**15 December 2009 (PwC report)**		**29 Mar to 23 April 2010 (averaging period)**	
Scenario	**Low**	**High**	**Low**	**High**
Up-front cost (basis points)	100	25	25	50
Discount rate (%)	9.69	9.69	9.72	9.72
Converted up-front cost (bppa)	16	4	4	8
Credit margin premium (bppa)	30	50	0	0
Total unit rate (bppa)	46	54	4	8

Source: PwC, *DNSP refinancing costs*, 15 February 2010, pp. 20–21; AER analysis.

1168 PwC, *DNSP refinancing costs*, February 2010, p. 19.
1169 Handley, *Note on the completion method*, April 2010, p. 11.
1170 AER, *Final decision, NSW distribution determination 2009–10 to 2013–14*, 28 April 2009, pp. 543–550.

After adjusting for current market data, accommodating the time value of money, accounting for volume only underwriting, and eliminating indirect costs, the AER considers that the costs of the commitment method are in the range of 4 to 8 bppa.

Summary of PwC approaches

Table J.4 summarises the AER's conclusion on the costs of the three approaches considered in the PwC report, with appropriate revisions and updates.

Table J.4: Comparison of the cost of the three PwC approaches

Method	PwC estimate	AER revised estimate
Completion method (bppa)	20–24	15–19
Commitment method (bppa)	22–24	0–19
Underwriting method (bppa)	46–54	4–8

Source: PwC, *DNSP refinancing costs*, February 2010 and AER analysis.

Based on the three approaches in the PwC report, and taking account of the midpoint of each range, the AER considers that the efficient benchmark costs for a refinancing plan are based on the underwriting method.

Comparison with the (standard) debt raising allowance under the ACG methodology

The AER notes that ETSA Utilities' proposal of an allowance for costs associated with the completion method is in addition to the (standard) debt raising costs based on the ACG methodology. Therefore, it is important to examine the ACG methodology to ensure that there is no double counting of costs. As Handley stated:[1171]

> In the draft determination, the AER has stated that an allowance of 9.1 basis points per annum (bppa) for debt raising costs is a reasonable benchmark for ETSA Utilities. However, Table 8.16 indicates that the bulk of this amount – 7.33 bppa – represents gross underwriting fees. Since the Completion Method and Underwriting share a common purpose, then it is not clear why there should be allowance for both the costs of the completion method and gross underwriting fees.

The AER notes that the terms of reference set by ETSA Utilities for PwC sought an estimate of general refinancing costs.[1172] Specifically, the terms of reference did not include an instruction to exclude costs that are already included in the (standard) debt raising costs allowance.

The AER considers that the ACG methodology used for assessing debt raising costs takes account of the management of refinancing risk. The 2004 ACG report was a comprehensive review of the transaction costs involved in raising debt (and equity).[1173] The brief was not constrained, but asked for inclusion of all aspects of the debt raising process for a benchmark firm. The AER notes the review included

[1171] Handley, *Note on the completion method*, April 2010, p. 9.
[1172] PwC, *DNSP refinancing costs*, February 2010, p. 30.
[1173] ACG, *Debt and equity raising costs*, December 2004, pp. 2–7.

detailed interviews with relevant entities, and that this specifically included an interview with Standard and Poor's.[1174]

The issue of refinancing risk was known and relevant when ACG undertook its analysis, consistent with the statements by Standard and Poor's, PwC and Handley referred to above. The AER considers that it is reasonable to conclude that ACG took into account the need for a refinancing plan to mitigate refinancing risk (to an appropriate level) when estimating the appropriate benchmark for debt raising costs.

Although the figures have been updated since 2004, the (standard) debt raising cost allowance still uses the same cost components recommended by ACG. This explicitly includes an underwriting component, currently estimated to be 7.2 bppa. The underwriting fee was described by ACG as:[1175]

> Traditionally, as in stockbroking, the underwriting fee represented a reward for risk taking. If the issue were not sold, the underwriter would take it up and guarantee proceeds to the issuer.

The AER notes that the underwriting description from the ACG report matches that in the PwC report. In particular, PwC included a 'volume only' underwriting method, where the underwriter did not guarantee the price at which the debt would be raised.[1176] ACG explicitly noted this type of underwriting, although it used a different label:[1177]

> With "best efforts" underwriting, a "bookbuild" is undertaken to determine the market–clearing price.

The AER notes that the underwriting cost estimate based on the ACG methodology (7.2 bppa) falls within the AER revised cost range based on the PwC report (4 to 8 bppa), albeit at the upper end of this range. The AER has decided to continue to use the ACG-derived estimate of 7.2 bppa for the underwriting component, noting that this is conservative relative to the midpoint of 6 bppa that would apply based on the PwC range. The AER considers that this advances both internal consistency—all components of the allowance are based on the same source—and regulatory consistency—since this figure is based on the same methodology as applied in previous regulatory decisions.

Finally, the AER considers that the ACG report presents a more comprehensive assessment of the benchmark costs associated with debt raising than the PwC report. ACG explicitly models—in addition to underwriting fees—legal and roadshow fees, company credit rating fees, issue credit rating fees, registry fees and paying fees.[1178] ACG added these categories to the underwriting fee to derive a range for debt raising costs of between 9 and 11 bppa.[1179]

1174 ACG, *Debt and equity raising costs*, December 2004, p. 6.
1175 ACG, *Debt and equity raising costs*, December 2004, pp. 37–38.
1176 PwC, *DNSP refinancing costs*, February 2010, p. 19.
1177 ACG, *Debt and equity raising costs*, December 2004, p. 38.
1178 ACG, *Debt and equity raising costs*, December 2004, pp. 51–52.
1179 This cost varies based on the size of the debt assumed.

PwC did not state whether any of these components have been included in its considerations, and if they were included in the overall cost estimates, this was not indicated. In one instance, PwC stated that it explicitly excluded legal costs:[1180]

> This amount does not reflect the additional administrative and legal costs that would be incurred as a consequence of negotiating a deferred settled bond transaction for a period of as long as 3 months.

On balance, the AER considers that the ACG methodology provides the most comprehensive total estimate of the costs involved in raising debt, including non-underwriting components.

AER conclusion

The AER considers that the benchmark firm should be compensated for the efficient costs of a refinancing plan. However, the AER does not consider that the allowance proposed by ETSA Utilities—based on the PwC report—should be added to the (standard) direct debt raising costs allowance based on the ACG methodology. The AER considers that this would result in double counting the costs of managing refinancing risk.

The AER considers that the allowance for (standard) direct debt raising costs already includes the efficient costs of a refinancing plan and that no increase in these costs is required.

[1180] PwC, *DNSP refinancing costs*, February 2010, p. 17.

K. Annual reporting requirements

In a number of chapters of this draft decision, the AER has indicated that ETSA Utilities will have to report certain information on an annual basis. This information is generally required for the administration of incentive schemes, to ensure compliance with approved control mechanisms, or for annual pricing purposes.

The purpose of this appendix is to provide a summary of the information ETSA Utilities must report 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 ETSA Utilities.

Further, the AER will require ETSA Utilities to provide regulatory accounts, consistent with its approved cost allocation methodology and in similar terms to the reporting requirements under ESCOSA's *Electricity Industry Guideline 1: Electricity Regulatory Information Requirements – Distribution*, 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 K.1: Annual reporting requirements

	Reporting requirement	**Purpose**
Annual inflation adjustment – chapter 4.	The percentage change in the Australian Bureau of Statistics 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 weighted average price cap (WAPC) each year.
Actual demand quantities – chapter 4.	Customer numbers, energy consumption, maximum demand broken down by tariff class.	Calculation of the WAPC each year.

	Reporting requirement	Purpose
Undergrounding allowance – chapter 4	Any proposed undergrounding allowance, including sufficient detail for the AER to be satisfied that clause 7.3(c)(ii) of the Electricity Pricing Order (SA) is met.	Calculation of the WAPC each year.
Transitional EDPD factors (K,Q, PU & SI and any under/over recovery of ESCOSA's demand management allowance) – chapter 4	A calculation of these transitional adjustments, including sufficient detailed information for the AER to confirm the calculations.	Calculation of the WAPC each year.
Transmission use of system (TUOS) unders & overs – chapter 4	Information as set out in appendix F of this decision.	Calculation of TUOS charges each year.
Ring fencing compliance – chapter 4	Annual ring fencing compliance report against the applicable guideline and approved cost allocation method.	To ensure compliance with the NER ring fencing requirements and to ensure the correct application of the control mechanisms for standard and alternative control services.
Service target performance incentive scheme (STPIS) – chapter 12	Report annual performance against the following parameters, consistent with section 3.1 of the national distribution STPIS: • Unplanned SAIDI • Unplanned SAIFI • MAIFI. ETSA Utilities is to divide its electricity network into segments by network type as specified in clause 3.1(c) of the national distribution STPIS for the purposes of reporting this information. Report performance against the customer service parameter: telephone answering.	The AER will use the unplanned SAIDI, unplanned SAIFI and the customer service performance to determine: • the penalties or rewards to apply by reference to the relevant performance targets set out at table 12.4 of the this draft decision. • the targets to apply for the 2015–20 regulatory control period.

	Reporting requirement	Purpose
STPIS (cont) – chapter 12	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 2010–15 data collection process.	
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 • actual costs of other specific uncontrollable costs incurred by ETSA Utilities, which ETSA Utilities proposes the AER considers for exclusion after assessment against the relevant principles expressed in clause 6.6.1(j) of the NER and the EBSS.	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 EBSS.

	Reporting requirement	Purpose
Demand management incentive scheme – chapter 14	Submission of annual report, as per requirements set out in AER, *DMIS – Energex, Ergon Energy and ETSA Utilities, October 2008*. Required information includes: • DMIA expenditure for each year of the next regulatory control period. Details of reporting requirements are set out in section 3.1.4 of the DMIS. • Calculations and explanations of foregone revenues for each year of the next regulatory control period. Details of reporting requirements are set out in section 3.2.4 of the DMIS.	Ex–post assessment of expenditure and compliance with the DMIA criteria, and approval of expenditures. Ex–post assessment of revenues foregone as a result of implementation of demand management projects approved under the DMIA, and approval of compensation.
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 period (a regulatory year). This reporting requirement is in addition to the requirements of the NER.

	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 service provider should disclose self insurance events each regulatory year and provide a brief description of the nature of the self insurance event in accordance with AASB 137 in its regulatory and audited financial accounts.
		AASB 137 requires 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.

L. Submissions

The AER received submissions on the draft decision and ETSA Utilities' revised regulatory proposal from the following interested parties:

AGL Energy Limited

Board of Tourism Kangaroo Island, Kangaroo Island Council and the Regional Development Australia Board joint submission

CitiPower Pty and Powercor Australia Ltd joint submission

DUET Group

EnergyAustralia

Energy Consumers Coalition of South Australia

Energy Users Association of Australia (2)

ETSA Utilities (2)

Hon Patrick Conlon MP, Minister for Energy

South Australian Council of Social Service

South Australia Department for Transport, Energy and Infrastructure

SP AusNet

Total Environment Centre Inc.

Trans Tasman Energy Group

TRUenergy Australia Pty Ltd

United Energy Distribution Pty Limited

UnitingCare Australia

Victorian electricity distribution businesses (joint submission)