ETSA Utilities

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ETSA Utilities Revised Regulatory Proposal 2010–2015

14 January 2010

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Executive summary

1

CONTEXT

South Australia's electricity distribution network is a strategic asset that constitutes a core component of the State's energy infrastructure, and which supports the ongoing growth and development of our State.

Similarly, ETSA Utilities is a key part of the fabric of the South Australian economy and community—proudly serving South Australians for over 60 years, initially as part of the original Electricity Trust of South Australia, and more recently as a stand-alone electricity distribution business established in the disaggregation of the State's electricity supply industry in the late 1990s.

As the principal electricity distribution network services provider in South Australia, our core business is the operation, construction and maintenance of the distribution network. On 1 July 2009, ETSA Utilities submitted a regulatory proposal (the Original Proposal) to the Australian Energy Regulator (AER) for the regulatory control period from 1 July 2010 to 30 June 2015 in accordance with the National Electricity Rules (the Rules).

The AER made a draft distribution determination on ETSA Utilities' Original Proposal, which was dated 25 November 2009 and published on 30 November 2009 (Draft Determination).

ETSA Utilities has carefully reviewed the matters raised by the AER in its Draft Determination, including, in particular, where the AER has made adjustments to ETSA Utilities' Original Proposal. This Revised Proposal has been prepared in response to the issues raised in the AER's Draft Determination.

This Revised Proposal is structured to mirror the chapters of the Original Proposal (except for the removal of the Business Overview from the Original Proposal and the addition of Control Mechanism for Alternative Control Services in the Revised Proposal). ETSA Utilities notes that although it has incorporated many of the AER's adjustments to its Original Proposal, this should not necessarily be taken as ETSA Utilities' acceptance of the rationale provided by the AER or its consultants for any relevant adjustment.

Finally, this Revised Proposal has been the subject of independent legal review for compliance with Chapter 6 of the Rules.

Under National Electricity Law (NEL), the AER's distribution determination must contribute to the achievement of the National Electricity Objective, which is the promotion of *'efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*

- *price, quality, safety, reliability and security of supply of electricity; and*
- *the reliability, safety and security of the national electricity system.'*

In line with the NEL objectives, ETSA Utilities considers that the Revised Proposal appropriately addresses the issues raised by the AER in its Draft Determination and balances the need to achieve appropriate service levels and sustainably address new expectations and cost drivers, whilst managing risk, obtaining a commercial return and delivering reasonable price outcomes for customers.

2

REVISIONS TO THE ORIGINAL PROPOSAL

ETSA Utilities notes that in its Draft Determination, the AER did not accept ETSA Utilities' energy sales forecasts and capital and operating expenditure forecasts in full. This Revised Proposal addresses these specific matters raised by the AER in its Draft Determination.

Consequent revisions to the Original Proposal include, but are not limited to:

- updated energy sales forecasts;
- updated capital expenditure forecasts;
- updated operating expenditure forecasts;
- the separation of the costs of providing metering services from those of standard control services, and the development of a separate price control for metering alternative control services;
- revised input cost escalators derived using methodologies congruent with those applied by the AER for the purpose of its Draft Determination, subject to important modifications and updates where relevant;
- a revised Weighted Average Cost of Capital (WACC); and
- other adjustments as required to address the issues raised in the Draft Determination.

The revisions contained within this Revised Proposal have been developed with consideration of the issues raised within the AER's Draft Determination, ETSA Utilities' consultants' advice, and additional analysis undertaken by ETSA Utilities.

2.1

REVISED SALES FORECASTS

The AER rejected ETSA Utilities' energy sales forecast as unrealistic. Instead, the AER substituted an alternative and significantly higher sales forecast by the Australian Energy Market Operator (AEMO).

ETSA Utilities has identified a number of limitations with this alternative forecast approach, which make it unsuitable for the purpose of forecasting ETSA Utilities' energy sales.

The energy sales forecast incorporated in the Original Proposal has been updated using recently available economic outlook and consumption trends. ETSA Utilities has been provided with extensive consultancy assistance in forecasting economic growth. This research has revealed three plausible economic scenarios, each of which may reasonably reflect future outcomes. A combination of these economic scenarios has been used for the Revised Proposal.

In addition to refreshing the economic forecast, ETSA Utilities reviewed and updated the analysis and supporting information to derive the impact of government energy efficiency/greenhouse policy measures. There is no doubt that governments are accelerating the development of these measures for households and businesses to complement the introduction of the Carbon Pollution Reduction Scheme (CPRS). The commitment of governments in this respect is demonstrated in the Council of Australian Governments' (CoAG) Intergovernmental Agreement and the National Strategy on Energy Efficiency (developed in the second half of 2009), which foreshadows a comprehensive suite of energy efficiency policy initiatives.

The Original Proposal incorporated adjustments to the sales forecast to take into account the influence of seven energy efficiency measures, which are not represented in historical data trends. An expert consultant has found that there is a sound basis for the incorporation of adjustments for each of those measures.

The adjustments for energy efficiency measures incorporated in this Revised Proposal have been derived giving special attention to issues raised by the AER's consultant, AEMO. Details of the analysis are provided with clear referencing to the data relied on which includes ETSA Utilities' customer information, government papers and reports by independent consultants.

Figure 1 presents ETSA Utilities' forecast average energy sales growth rates by sector.

2.2

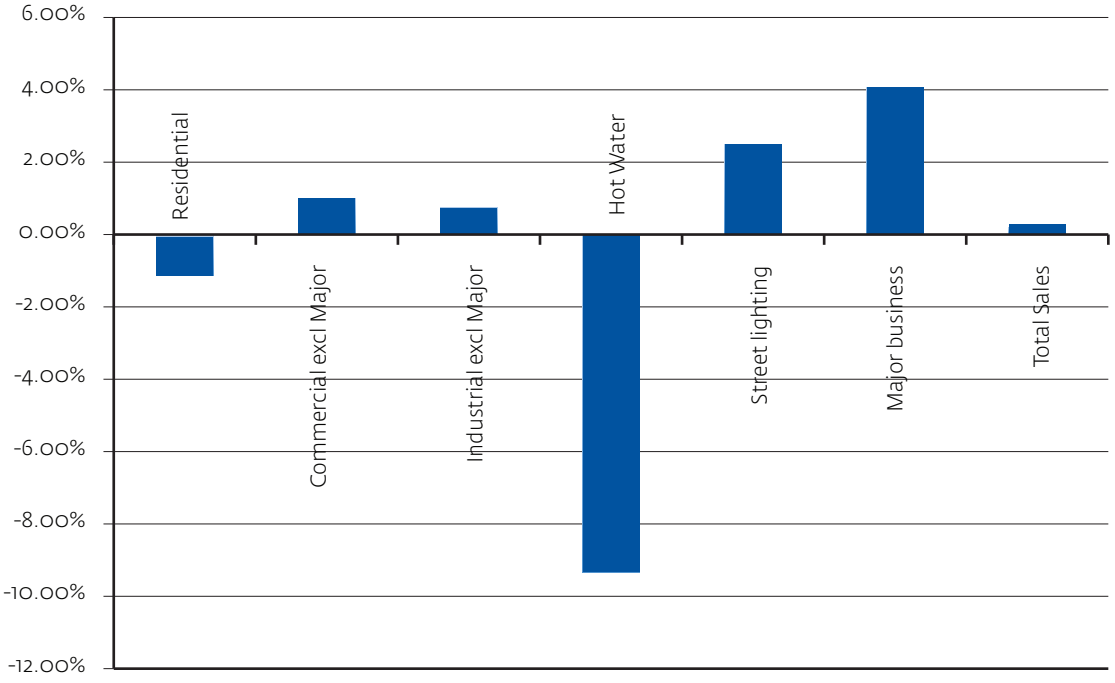
REVISED CLASSIFICATION OF SERVICES

ETSA Utilities' Original Proposal incorporated the AER's proposed classification of services contained in the Framework and approach paper, other than the intended reclassification of metering services as alternative control services. ETSA Utilities also submitted its draft Negotiating Framework for negotiated services for the approval of the AER as part of the Original Proposal.

In its Draft Determination, the AER confirmed its view that the alternative control service classification should apply to 'variable' and 'exceptional' metering services, as defined in the Framework and approach paper.

In ETSA Utilities' view, the AER's decision to classify certain metering services as alternative control services is inappropriate, as it is inconsistent with existing regulatory arrangements, has not been adequately justified or consulted upon, and results in inefficient outcomes. Nevertheless, ETSA Utilities has ascertained that it is able to implement the AER's requirements by 1 July 2010, although it will require interim arrangements be put in place initially.

Figure 1: ETSA Utilities' energy sales forecast by sector



2.3

REVISED EXPENDITURE

2.3.1
Operating Expenditure

ETSA Utilities proposes a revised operating expenditure program (excluding metering services) of approximately $1,081 million (real, June 2010) for the 2010–2015 regulatory control period. This is approximately 4 percent higher than the total operating expenditure allowance of $1,044 million (real, June 2010) proposed by the AER[1] in its Draft Determination—an allowance which also included ETSA Utilities' alternative control metering services costs.

Compared to ETSA Utilities' Original Proposal, the revised total operating expenditure forecast by ETSA Utilities for the 2010–2015 regulatory control period, excluding metering services, is approximately 4 percent lower than originally forecast[2]—an original forecast which also excluded operating expenditure associated with feed-in tariffs. Adjusting ETSA Utilities' original forecast such that it includes the operating expenditure associated with feed-in tariffs and excludes the operating expenditure associated with metering services results in ETSA Utilities' revised total operating expenditure forecast being approximately 5 percent lower than its original forecast.

ETSA Utilities has accepted the AER's Draft Determination for its proposed expenditures, with some exceptions, which include (but are not limited to) the following:

- Escalation of emergency response;
- Asset age escalation;
- Self insurance; and
- Debt raising costs.

ETSA Utilities' revised operating expenditure is summarised in Table 1.

2.3.2
Capital Expenditure

ETSA Utilities proposes a revised total net capital expenditure forecast for the 2010–2015 regulatory control period, excluding metering services, of approximately $1,793 million (real, June 2010)[3]. This is approximately 10 percent higher than the total net capital expenditure allowance of $1,628 million (real, June 2010) proposed by the AER[4] in its Draft Determination.

Table 1: ETSA Utilities' revised total forecast operating expenditure for the 2010–2015 regulatory control period (excluding metering)

Year	2010/11	2011/12	2012/13	2013/14	2014/15
Controllable costs					
Network operating costs	28.2	28.6	29.1	29.8	30.6
Network maintenance costs	78.3	80.2	83.2	87.1	89.5
Customer services	21.3	21.8	22.3	22.8	23.5
Allocated costs	48.4	51.8	54.0	58.0	59.0
Total controllable costs	176.2	182.4	188.6	197.7	202.6
Uncontrollable costs					
Superannuation	9.8	9.9	10.0	10.2	10.4
Self insurance	3.0	3.2	3.3	3.5	3.8
Feed-in tariffs	7.0	8.7	10.1	11.1	11.7
Debt raising costs	3.5	3.6	3.7	3.8	3.9
Total uncontrollable costs	23.2	25.3	27.2	28.6	29.8
Total operating expenditure forecast	**199.5**	**207.7**	**215.8**	**226.4**	**232.3**

Real, June 2010 $M

1 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.245.

2 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.150.

3 Any differences between this amount and the total of Table 1 are due to rounding.

4 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.175

2.4

Compared to ETSA Utilities' Original Proposal, the revised total net capital expenditure forecast by ETSA Utilities for the 2010–2015 regulatory control period, excluding metering services, is approximately 20 percent lower[5]. This reflects a range of factors, including the removal of a significant capital project from forecast capital expenditure, and its subsequent inclusion as a component of the pass through regime.

ETSA Utilities has accepted the AER's Draft Determination for its proposed expenditures, with some exceptions, which include (but are not limited to) the following key categories:

- Capacity—Low Voltage;
- Asset replacement;
- Safety—substation fencing;
- Security of supply—network control;
- Escalators; and
- Equity raising costs.

ETSA Utilities' revised capital expenditure is summarised in Table 2.

REVISED WACC

In response to the Draft Determination, and without necessarily agreeing with the basis for the AER's Draft Determination in respect of these parameters, ETSA Utilities has revised its Original Proposal to:

- adopt a SORI determined value for the market risk premium parameter of 6.5 %; and
- measure the debt risk premium by reference to the CBA Spectrum.

However, for the reasons set out in this Revised Proposal, ETSA Utilities does not accept the AER's Draft Determination with respect to the use of an imputation credit factor of 0.65 and maintains that an imputation credit factor of 0.5 is consistent with the requirements of the Rules.

Table 2: ETSA Utilities' revised total forecast net capital expenditure for the 2010–2015 regulatory control period (excluding metering services)

Year	2010/11	2011/12	2012/13	2013/14	2014/15
Network expenditure—demand driven					
Capacity	131.9	176.1	127.5	120.7	115.0
Customer Connection (gross)	153.9	155.6	140.8	146.5	149.0
Customer Contributions	(124.5)	(125.2)	(112.3)	(116.8)	(119.2)
Total demand driven—net	161.4	206.6	156.0	150.5	144.8
Network expenditure—quality, reliability and security of supply					
Asset Replacement	57.6	65.2	63.2	64.7	63.9
Security of Supply	13.8	16.3	16.8	13.9	8.7
Reliability	4.7	4.7	4.6	4.6	4.6
Total quality, reliability and security of supply	76.2	86.2	84.6	83.2	77.2
Network expenditure—safety and environment	25.3	34.3	35.9	35.7	35.0
Non-network expenditure	65.6	57.2	66.6	71.8	79.6
Other—superannuation and equity raising costs	24.0	8.6	8.7	8.8	9.0
Total capital expenditure forecast (net)	352.5	392.9	351.8	350.1	345.6

Real, June 2010 $M

5 Based on expenditure in ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.108.

2.5

REVISED OPENING ASSET BASE

The AER has accepted ETSA Utilities' proposed opening RAB, except for adjustments to the Regulated Asset Base (RAB) for the valuation of easements and the correction of a modelling error. ETSA Utilities has not incorporated the AER's Draft Determination for the roll forward of the RAB to 2010 in this Revised Proposal, with respect to:

- the valuation of easements; and
- ESCOSA's treatment of capital contributions

ETSA Utilities proposes 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). ETSA Utilities considers that the AER's grounds for its Draft Determination in respect of the valuation of easements have been affected by fundamental errors.

ETSA Utilities proposes an increase to the opening RAB as at 1 July 2005 of $16.3 million, to correct for the erroneous adjustment made by the Essential Services Commission of South Australia (ESCoSA) in determining the opening asset base at 1 July 1999. ETSA Utilities' position remains that there is a compelling basis for the AER to correct the error made by ESCoSA.

ETSA Utilities has calculated a revised RAB forecast for the next regulatory control period. This calculation uses the AER's Roll Forward Model and Post-Tax Revenue Model (PTRM) and applies the same methodology as in the Original Proposal. It incorporates the changes to the valuation of easements, ESCoSA's treatment of capital contributions and changes to the proposed capital expenditure allowance.

ETSA Utilities has determined that its revised opening RAB as at 1 July 2010 is $2,983.5 million ($June 2010)[6].

2.6

REVISED REVENUE AND X FACTORS

ETSA Utilities has calculated the annual revenue requirements for the provision of standard control services and alternative control services for each year of the next regulatory control period, and developed the P_0 and X factors to be applied as part of the price controls to apply to these services. These calculations have been undertaken in accordance with the requirements of the National Electricity Rules, and employ the AER's PTRM.

The revenue requirements and prices presented in this Revised Proposal, while they are representative, are at this stage indicative or 'placeholder' numbers only, as they have been calculated by reference to necessarily interim inputs that will be finalised in the future. Indicative prices presented in chapter 16 are, while limited by their relevant price controls, potentially subject to further amendment in connection with ETSA Utilities' pricing proposal to the AER in May 2010. Table 3 presents the annual revenue requirements proposed by ETSA Utilities in this Revised Proposal for standard and alternative control services.

The AER's Draft Determination excluded the EDPD carryover effect from the building blocks. The PTRM has been prepared in line with the Draft Determination. However, there will be a significant carryover to be returned to customers. Allowing a preliminary estimate of $28 million for this item, and a smooth price path for customers, the PTRM P_0 and X_1 have been determined such that a constant price increase of about 10.5 percent is passed onto customers on average. Table 4 presents the proposed P_0 and X factors for standard and alternative control services for the next regulatory control period.

Table 3: Annual revenue requirements for standard control and alternative control services (unsmoothed)

	2010/11	2011/12	2012/13	2013/14	2014/15
Standard control services	642.7	699.1	757.3	819.2	874.7
Alternative control services	19.0	21.0	23.3	25.4	27.7

Real, June 2010, $M

Source: Tables 16.4 and 16.5

Table 4: P_0 and X Factors for standard control and alternative control services

	2010/11	2011/12	2012/13	2013/14	2014/15
	P_0	X_1	X_2	X_3	X_4
Standard control services	-10.4%	-10.5%	-10.5%	-10.5%	-10.5%
Alternative control services	-9.2%	-9.2%	-9.2%	-9.2%	-9.2%

Source: Tables 16.6 and 16.7

6 This includes an amount attributed in this Revised Proposal to metering services of $80.5 million ($June 2010).

3

OUTCOMES FOR SOUTH AUSTRALIANS

Consistent with the Original Proposal, ETSA Utilities is confident that the Revised Proposal presents arguments that represent a prudent, constrained, efficient and sustainable response to the Draft Determination with regard to electricity distribution services and associated risks.

Implementation of this Revised Proposal, with the proposed building blocks and indicative price path, would result in a real price increase for a typical residential customer's electricity bill of an average of $36 annually over the next regulatory control period. A typical residential customer's total electricity bill currently amounts to approximately $1,200 per annum (including GST).

1

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Introduction

1

INTRODUCTION

On 1 July 2009, ETSA Utilities submitted a regulatory proposal (the Original Proposal) to the Australian Energy Regulator (AER) for the regulatory control period from 1 July 2010 to 30 June 2015 in accordance with the National Electricity Rules (the Rules).

The AER made a draft distribution determination on ETSA Utilities' Original Proposal, which was dated 25 November 2009 and published on 30 November 2009 (Draft Determination).

This document and its attachments comprise:

- ETSA Utilities' revised regulatory proposal in response to the AER's Draft Determination for the regulatory control period, 1 July 2010 to 30 June 2015; and
- ETSA Utilities' interim submission on the AER's Draft Determination,collectively referred to in this document as ETSA Utilities' Revised Proposal.

The Revised Proposal is supported by:

- a disc containing copies of additional detailed internal ETSA Utilities documentation to substantiate the information presented in the Revised Proposal and its principal attachments;
- additional detailed internal documentation that substantiates the information presented in the Original Proposal and its principal attachments as presented to the AER on July 1 2009 for those aspects of the Original Proposal where ETSA Utilities proposes no revision;
- other specific responses according to the requirements of the Regulatory Information Notice (RIN) dated 22 April 2009; and
- a disc containing copies of other documents referred to and relied upon by ESTA Utilities in this Revised Proposal.

1.1

PURPOSE OF THE REVISED PROPOSAL

ETSA Utilities' Original Proposal has been the subject of compliance confirmation, public consultation and detailed review by the AER and its consultants. On 30 November 2009, the AER published its Draft Determination in response to ETSA Utilities' Original Proposal. ETSA Utilities has made revisions to its Original Proposal so as to incorporate the substance of any changes required to address matters raised by the Draft Determination or the AER's reasons for the Draft Determination. As noted previously, this document also forms ETSA Utilities' interim submission on the AER's Draft Determination.

This Revised Proposal has been prepared in accordance with clauses 6.10.2(c) and 6.10.3 of the Rules.

1.2

STRUCTURE AND APPROACH

This Revised Proposal is structured to mirror the chapters of the Original Proposal (except for the removal of the Business Overview from the Original Proposal and the addition of Control Mechanism for Alternative Control Services in the Revised Proposal). ETSA Utilities has reviewed all of the matters raised by the AER in its Draft Determination including, in particular, where the AER has made adjustments to ETSA Utilities' Original Proposal. ETSA Utilities has prepared this Revised Proposal to be consistent with the Draft Determination, with the exception of the specific deviations which are discussed in each chapter. Where ETSA Utilities has not revised its Original Proposal, the Original Proposal including the relevant attachments and supporting information remains the current regulatory proposal. ETSA Utilities notes that although it has incorporated many of the AER's adjustments to its Original Proposal, this should not be taken as ETSA Utilities' acceptance of the rationale provided by the AER or its consultants for any relevant adjustment.

ETSA Utilities has updated the information required to be submitted by Schedule 6.1 of the Rules and the Regulatory Information Notice (RIN) dated 22 April 2009, to reflect the Revised Proposal. This updated material is either contained in the relevant chapter of the Revised Proposal, the revised RIN pro forma template or supporting information submitted with the Revised Proposal.

The structure of the Revised Proposal is as follows:

Chapter	Category
2	Classification of services and negotiating framework
3	Control mechanism for standard control services
4	Control mechanism for alternative control services
5	Peak demand and sales forecasts
6	Forecast capital expenditure
7	Forecast operating expenditure
8	Pass-through events
9	Demand management
10	Service standard framework
11	Efficiency benefit sharing scheme
12	Regulated asset base
13	Weighted average cost of capital
14	Depreciation
15	Estimated cost of corporate income tax
16	Indicative revenue and pricing

1.3

CONFIDENTIALITY

Clause 6.8.2(c)(6) of the Rules requires ETSA Utilities to indicate any parts of the Revised Proposal that it deems to be confidential and for which it proposes suppression from publication on that ground. ETSA Utilities claims confidentiality over a number of attachments and has provided the confidential information in these attachments to the AER separate to the Revised Proposal. ETSA Utilities requests that the AER does not disclose the information contained in these attachments to any person outside the AER, except with the written specific approval of ETSA Utilities.

1.4

COMPLIANCE

Independent legal review has confirmed that this Revised Proposal is fully compliant with the requirements of the National Electricity Rules, including references within the Rules to other subsidiary instruments.

Further, as required by the Rules, two Directors of ETSA Utilities have certified the reasonableness of the key assumptions underlying the capital and operating expenditure forecasts. The certification is provided as Attachment A.1 to the Revised Proposal.

2

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Classification of services and negotiating framework

2

CLASSIFICATION OF SERVICES AND NEGOTIATING FRAMEWORK

In this chapter of the Revised Proposal, ETSA Utilities reviews the AER's Draft Determination on the classification of its Distribution Services and the Negotiating Framework.

In the Framework and approach paper[7], the AER indicated its likely approach to the classification of services. This proposal broadly followed the existing arrangements in place under the EDPD, with:

- prescribed distribution services being classified as direct control services, and further classified as standard control services; and
- excluded services being classified as negotiated distribution services.

The AER indicated its intention to depart from the former regulatory approach in respect of classifying 'variable' standard small customer metering services and two 'exceptional' cases of large customer metering services as alternative control services.

In its Original Proposal, ETSA Utilities agreed with the AER's proposed classification of services, with the exception of the metering services that the AER had indicated its intention to depart from the previous regulatory approach. A minor variation to the classification of services was proposed by ETSA Utilities, in the interests of simplifying the administrative arrangements and reducing costs. ETSA Utilities agreed that the 'variable' and 'exceptional' metering services could be unbundled, but proposed that they would remain classified as standard control services.

ETSA Utilities also submitted its draft Negotiating Framework for negotiated services for the approval of the AER.

In its Draft Determination, the AER confirmed that the alternative control service classification would apply to the 'variable' and 'exceptional' metering services, as defined in the Framework and approach paper.

The AER also set out the Negotiated Distribution Service Criteria (NDSC), which would apply during the 2010–15 regulatory control period and requested that a number of modifications be made to the Negotiating Framework, mainly to align with the NDSC requirements.

7 Final *Framework and approach Paper ETSA Utilities 2010–15, AER*, November 2008.

2.1

RULE REQUIREMENTS

Clauses 6.12.1(1), (15) and (16) of the Rules require the AER to make two constituent decisions concerning the classification of services:

1. the classification of the services to be provided by ETSA Utilities during the regulatory control period (under Part B of the Rules); and
2. the NDSC for the DNSP and any associated negotiating framework to apply to the DNSP for the regulatory control period (under Part E of the Rules governing the making of a distribution determination).

2.2

ETSA UTILITIES' ORIGINAL PROPOSAL

Chapter 3 of ETSA Utilities' Original Proposal described the proposed classification of its distribution services. ETSA Utilities indicated its support for most aspects of the AER's proposed classification of distribution services. The Original Proposal was substantively consistent with the AER's Framework and approach paper, differing only in some minor respects.

Accompanying the Original Proposal, ETSA Utilities also submitted a Negotiating Framework for the approval of the AER. This document was intended to accommodate two important features of the existing excluded services regime:

- the existence of specific jurisdictional requirements concerning customer capital contributions; and
- that certain types of high volume, repetitive services that were classified as negotiated services in the Framework and approach paper are covered by a Price List under the current regulatory arrangements.

2.2.1 Classification of services

There was one material aspect of the AER's proposed classification of services with which ETSA Utilities did not agree, and where ETSA Utilities proposed what it considered to be a simpler but equally effective arrangement to meet the AER's requirements. This related to the classification of metering related services.

ETSA Utilities proposed two changes to the AER's proposed classification of distribution metering services in order to better meet the requirements of the Rules. These were:

1. Classification of the 'variable' component of metering service for small customers as a standard control service, rather than as an alternative control service. The metering contestability issues raised by the AER and others were to be resolved by unbundling meter charges from the price of network connection; and
2. Classification of the 'exceptional' Type 1–4 metering of large customer metering installations as standard control services, rather than alternative control services. As with the small customer charges, the charges for those services would also be recovered as separate price components.

In addition, ETSA Utilities commented that the AER's description of standard small customer metering services should be framed in terms of the service involved, rather than the type of meter employed. The classification would not then be affected by a potential change in the technology of standard metering hardware, such as from Type 6 accumulation meters to Type 5 manually read interval meters.

The reasons for proposing these changes to the AER's Framework and approach classifications were set out in detail in the Original Proposal.

ETSA Utilities provided a full list of the services that it currently provides as excluded distribution services, including some additional services and clarification of the definitions of other services that had been included in the Framework and approach paper.

2.2.2 Negotiating Framework

ETSA Utilities will continue to provide a broad range of services to customers, which are defined as Excluded Services under the current regulatory regime. Specific jurisdictional arrangements are currently in place for these services. In the Framework and approach paper, the AER proposed that these services would be classified as negotiated services for the 2010–15 regulatory control period.

ETSA Utilities developed its draft Negotiating Framework to incorporate different categories of negotiable services into a single document. The document was tailored to accommodate legacy arrangements associated with:

- Chapter 3 of the current Electricity Distribution Code (EDC), which amongst other things provides specific requirements on the process and timing of connection provision on customer capital contributions[8]; and
- Guideline 14, which contains the pricing principles, information disclosure and dispute provisions for ETSA Utilities' excluded services. ETSA Utilities publishes a price list for a range of repetitive, high volume, relatively low value services, subject to this Guideline.[9, 10]

Within the Negotiating Framework, ETSA Utilities subdivided the range of negotiable services into the following classifications:

- Individually negotiated services, where an individual quotation would remain necessary because of the diversity of services and variability of costs. Those services were further subdivided into connection services, associated with connection to the network, and miscellaneous services.
- Price List services, reflecting the arrangements in place under the current scheme.

In the case of Price List services, a process for consultation in establishing the prices, the associated pricing principles and information disclosure was proposed, similar to that which had been established in NSW.

8 Electricity Distribution Code EDC/06 (As last varied in December 2006), Essential Services Commission of South Australia, 1 January 2003.

9 Excluded Services Regulation—Distribution Electricity Industry Guideline No. 14, Essential Services Commission of South Australia, December 2005.

10 Excluded Service Charges effective 1 January 2009, ETSA Utilities, 2 November 2009.

2.3

THE AER'S DRAFT DETERMINATION

Chapter 2 of the AER's Draft Determination sets out its proposals concerning the classification of services and the negotiating framework associated with those services which have been classified as negotiated distribution services.

Within this chapter, the AER set out its proposed requirements concerning the assignment of customers to tariff classes, in section 2.6.2. This matter was covered in chapter 4 of ETSA Utilities' Original Proposal and is now covered in chapter 3 of this Revised Proposal, as it is more closely associated with the operation of the control mechanism for standard control services.

2.3.1
Classification of services

Chapter 2 of the AER's Draft Determination did not accept ETSA Utilities' Original Proposal to classify variable standard small customer metering services, and the exceptional cases of large customer metering services, as standard control services. It maintained that those metering services should be classified as alternative control services.

In arriving at this decision, the AER noted the relevant factors to which it must have regard under clause 6.2.2 of the Rules. In relation to the Rule requirement that the AER must have regard to the desirability of a consistent regulatory approach to similar services (clause 6.2.2(c)(4)), the AER commented that there was inconsistency between jurisdictions in relation to the classification of metering services.[11] ETSA Utilities notes that in the jurisdictions referred to by the AER, being NSW, Victoria and Queensland, metering services are not, or are not proposed to be, classified as alternative control services.

On the matter of describing the above-mentioned metering services in terms of the actual service provided, rather than in terms of the type of meter employed, the AER did not alter its description of the services.

The AER accepted a number of ETSA Utilities' proposed additions and clarifications to the list of negotiated services, subject to submissions in response to its Draft Determination.

2.3.2
Negotiated Distribution Service Criteria and Negotiating Framework

Following ETSA Utilities' submission of its Original Proposal and draft Negotiating Framework, the AER published the proposed NDSC, which would apply to ETSA Utilities.[12]

Chapter 3 of the AER's Draft Determination reviewed the proposed NDSC. Appendix C to the Draft Determination sets out the NDSC, which the AER did not alter in response to submissions. Appendix D set out a number of detailed amendments, which the AER has required to be made to ETSA Utilities' proposed Negotiating Framework.

The AER's requirements concerning changes to ETSA Utilities' Negotiating Framework for negotiated distribution services were also set out in Chapter 3. The main changes are summarised as follows:

- removal of the pricing principles, which ETSA Utilities had proposed to apply to Price List services and substitution of the requirements of the NDSC;
- a requirement that the Price List (for high volume, repetitive services) be indicative of the negotiated service prices and subject to negotiation;
- broadening of the types of information that may be provided to applicants; and
- amendments to the dispute resolution provisions to reflect their administration by the AER.

Appendix D of the Draft Determination sets out the AER's detailed requirements concerning amendments to ETSA Utilities' proposed Negotiating Framework.

11 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p 16.

12 Call for submissions—Proposed Negotiated Distribution Service Criteria for ETSA Utilities, AER, July 2009.

2.4

ETSA UTILITIES' RESPONSE TO THE AER'S DRAFT DETERMINATION

2.4.1
Classification of services

In ETSA Utilities' view, the AER's decision to classify certain metering services as alternative control services is inappropriate, as the AER did not:

- maintain consistency with the existing jurisdictional arrangements in South Australia;
- adequately justify why ETSA Utilities' alternative and simpler proposal, which would have achieved the same objective of unbundling metering costs to facilitate metering competition, was rejected;
- adequately consider the administrative implications of its decision on ETSA Utilities or those retailers that operate in the South Australian jurisdiction. The system, billing and reporting implications of the AER's decision are not trivial and are not, as the AER has stated, solely one-off costs[13];
- consult with retailers to determine whether their billing systems can accept the more complex network pricing arrangements which would ensue; nor
- consult with retailers to determine in what form they would pass through the network pricing components in their retail bills to customers.

ETSA Utilities also notes that the AER has not changed its description of basic 'fixed' and 'variable' metering services to avoid reference to the Type of meter (Type 5 or Type 6). With the rapid advances in metering technology that are taking place, this may well impose an artificial barrier to ETSA Utilities' adoption of new metering technology during the 2010–15 regulatory control period.

ETSA Utilities notes the AER's proposal to include additional negotiated services and clarifications and has incorporated this in its Revised Proposal.

2.4.2
Negotiated Distribution Service Criteria and Negotiating Framework

ETSA Utilities notes the AER's NDSC set out in Appendix C of the Draft Determination. ETSA Utilities has incorporated the AER's NDSC in this Revised Proposal.

ETSA Utilities also notes the changes to the draft Negotiating Framework required by the AER and has incorporated those changes in this Revised Proposal. Those changes will have the effect of increasing the administrative burden placed upon ETSA Utilities, as described in section 2.5 below.

13 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, AER, p15.

2.5

REVISED PROPOSAL

2.5.1
Classification of services

Standard control services

The standard control services and alternative control services were set out in Appendix 1 of the AER's Draft Determination as items A.1 to A.6 inclusive and have not been repeated in this Revised Proposal. ETSA Utilities has incorporated the AER's classification of services in this Revised Proposal.

Alternative control services

Notwithstanding that ETSA Utilities considers the AER's decision to classify variable standard small customer metering services and exceptional cases of large customer metering services as alternative control services to be inappropriate, it has had further opportunity to assess whether it would be possible to implement the necessary changes to its systems and processes before 1 July 2010. ETSA Utilities has now concluded that these arrangements could be progressively introduced, with interim arrangements put in place initially.

The limitations of the current billing system will restrict the number of metering tariff components that ETSA Utilities will be able to introduce in 2010–11. Modifications to the billing system will permit the introduction of additional metering alternative control service tariff components from the following year. The introduction of additional tariff categories will be dealt with as part of the annual tariff adjustment process.

While not agreeing with the basis for the AER's Draft Determination to classify variable standard small customer metering services and exceptional cases of large customer metering services as alternative control services, and notwithstanding the administrative challenges and costs associated with the implementation of this classification, in this Revised Proposal ETSA Utilities has incorporated the AER's classification of certain metering services as alternative control services.

The additional operating costs associated with the establishment and administration of these metering services as alternative control services have been factored into the cost build up for these services.

There is an additional fee that ETSA Utilities proposes for inclusion as an alternative distribution service. That fee would apply where an existing ETSA Utilities meter at a customer premises was removed and replaced with a meter supplied by another metering provider. ETSA Utilities proposes that such fee would equate to the sum of:

- the average written-down value of the customer's meter, which would represent the loss to ETSA Utilities occasioned by the replacement; and
- the operating cost incurred as a result of the meter change-over not otherwise recovered.

By recognising this fee as a capital contribution under the alternative control service pricing arrangements, the integrity of the alternative control building block model costs would be preserved.

Accordingly, ETSA Utilities proposes an additional item for inclusion in the list of alternative control services, as follows:

[A.6A] Meter customer exit fee

a. The asset related and administrative cost associated with an ETSA Utilities meter being replaced by that of another meter provider.

Negotiated distribution services

ETSA Utilities has incorporated the classification of negotiated distribution services set out in Appendix 1 of the AER's Draft Determination as items A.7 to A.16. This table has not been repeated in this Revised Proposal.

Revised Proposal

ETSA Utilities has incorporated the classification of services proposed in Appendix A of the AER's Draft Determination in this Revised Proposal.

ETSA Utilities has incorporated an additional item for inclusion in the list of alternative control services, as follows:

[A.6A] Meter customer exit fee

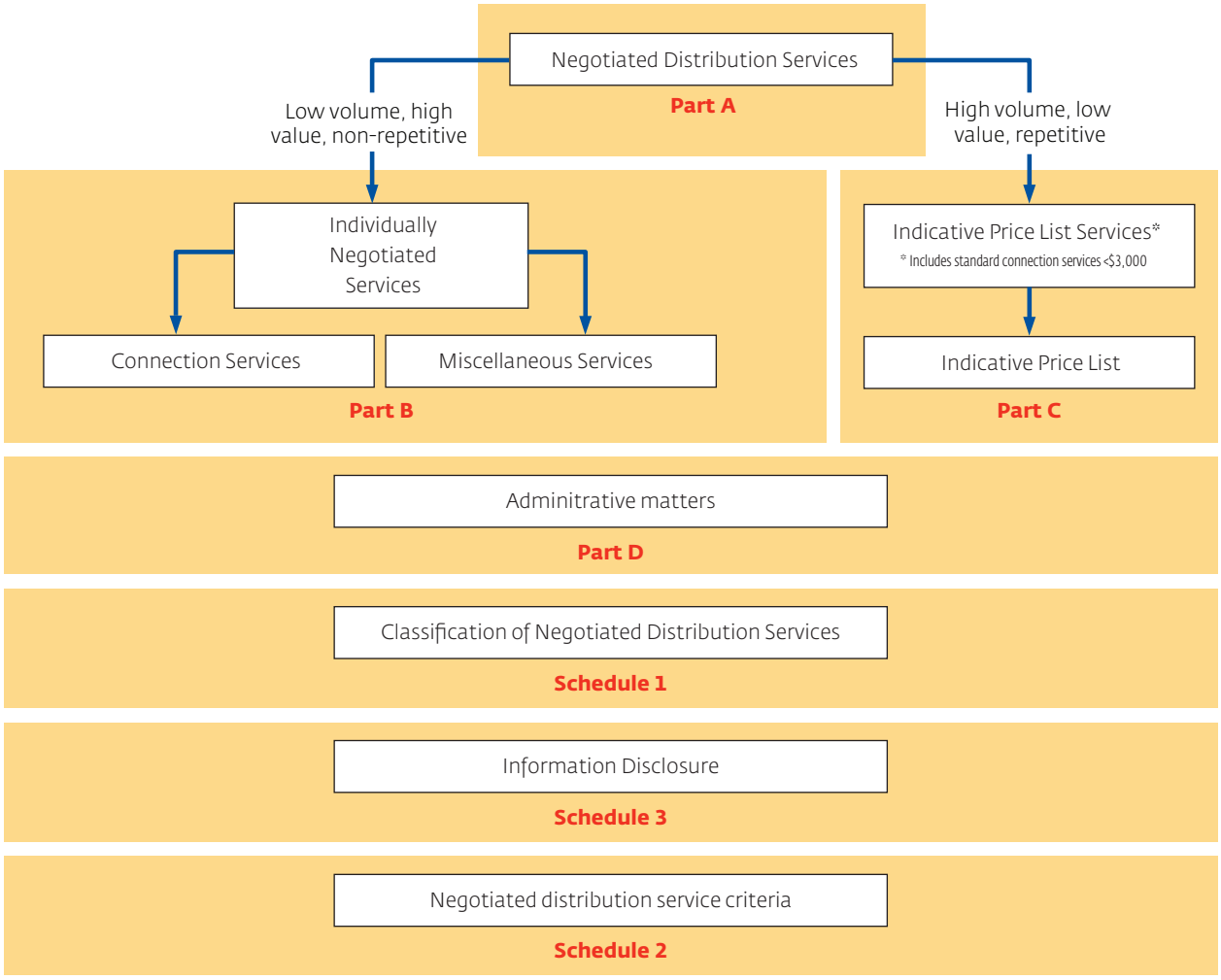
a. The asset related and administrative cost associated with an ETSA Utilities meter being replaced by that of another meter provider.

2.5.2 Negotiating Framework

ETSA Utilities has incorporated a number of amendments to the Negotiating Framework, in accordance with the AER's Draft Determination. The revised Negotiating Framework is presented as Attachment B.1 to this Revised Proposal.

The revised structure of this document is presented in Figure 2.1.

Figure 2.1: Structure of revised Negotiating Framework



The AER's amendments to the Negotiating Framework and associated processes will have a marked effect on the administrative requirements imposed upon ETSA Utilities.

ESCoSA followed an extended period of discussion and consultation before establishing the current prescriptive regime, where customer charges are either fixed (in the Price List) or determined in accordance with EDC Chapter 3. This efficient arrangement requires very little subsequent administrative effort to be spent negotiating the charge/price for such services.

ETSA Utilities considers that the AER's proposed amendments to the Negotiating Framework will significantly impact on the resources required to negotiate the provision of a negotiated distribution service. The major impact of this change is expected to be in negotiating the provision of new, non-standard or upgraded connection services.

ETSA Utilities capitalises all work associated with new connections or alterations to connections, as it relates to additions or amendments to the distribution system. Therefore ETSA Utilities will require additional capital expenditure to accommodate the increased resources required to negotiate these distribution services under the Negotiating Framework.

ETSA Utilities has always employed a clearly specified regime for the connection of customers to the distribution system and has applied fixed prices (ie. effectively non-negotiable in individual situations) for high volume low cost distribution services. Therefore, it is difficult to determine the additional resource requirement under a negotiation regime versus ETSA Utilities' previously clearly specified regime.

In an effort to determine the likely additional costs that ETSA Utilities would incur under the proposed Negotiating Framework, ETSA Utilities undertook a high level benchmarking exercise with sister companies, Powercor and CitiPower in Victoria. The Victorian regime is less prescriptive than currently applies in South Australia. ETSA Utilities determined the percentage of administrative costs versus the costs of the projects over the last few years. ETSA Utilities then used the average administrative percentage for both Powercor and CitiPower, which determined that an additional $1.2 million (2008 dollars) per annum in capital expenditure (which equates to about 13 full time employees) is required.

Additional capital expenditure costs have therefore been factored into the capital expenditure requirements of this Revised Proposal, in chapter 6.[14]

There will also be some additional administrative requirement occasioned by the AER's proposal that all Price List services be individually negotiable and the Price List be regarded as indicative. However, as the impact of this cannot be determined with reasonable certainty no additional operating costs have been included in this Revised Proposal.

ETSA Utilities is aware that the South Australian Government (via the Department of Transport, Energy and Infrastructure) is proposing to derogate from the NER and continue the current application of Chapter 3 of the EDC. The form of that derogation is not currently known and therefore it is difficult to determine the effect on ETSA Utilities' future negotiations with customers. It is understood that the derogation would only impact on new customer connections and upgrades to connections and would not alter the requirement imposed by the AER to individually negotiate Price List services. Consequently, even with the derogation in effect, ETSA Utilities would still require additional resources under the revised Negotiating Framework.

Revised Proposal

ETSA Utilities has modified the Negotiating Framework to incorporate the AER's requirements in the Draft Determination. The amended Framework is submitted as an attachment to this Revised Proposal.

14 CSO3: Negotiated framework extra resources derivation.xls

Table 2.1 provides a summary of the amendments made to the revised Negotiating Framework in accordance with the AER requirements (as detailed in Appendix D of the AER's Draft Determination).

Table 2.1: Ammendments to the Negotiating Framework

No.	AER required change	EU response
1	Removal of the pricing principles in schedule 3 and referred to throughout the negotiating framework	Reference to pricing principles replaced with references to the NDSC
2	Removal of schedule 4—connections requiring network extension and/or augmentation	Removed
3	Amendment to section 6, to capture clause 6.7.5(c)(2) of the NER. The amendment must acknowledge that the list of information types provided by section 6 in no way restricts the type of information to be provided if reasonably required by the applicant	See clause 6.1(g)
4	Removal of the footnote in section 6, page 5, stating that for price list services, commercial information will be provided by virtue of the annual price list. Section 6 must be amended, ensuring clause 6.7.5(c)(2) of the NER is met for all negotiated distribution services including Price List services	Amended—see footnote No.1 on the bottom of page 5. Where Service Applicants are directed in the first instance to the information published annually
5	Amendment to section 7, to remove references to ETSA Utilities' proposed pricing principles. Section 7 or elsewhere in the negotiating framework as appropriate, must be amended, ensuring clause 6.7.5(c)(3) of the NER is met for all negotiated distribution services, including Price List services. This clause requires ETSA Utilities to identify and inform service applicants of the reasonableness of costs and their movements, how its prices/charges reflect these costs, and include arrangements for the assessment and review of the charges and the basis upon which they were made. The AER requires that the NDSC be the basis referred to in this clause	Amended to reflect requirements. In particular, see clause 6.1(e)
6	Amendment to part C or elsewhere in the negotiating framework as appropriate, to address clause 6.7.5(c)(5) such that time—limit provisions be applied to all negotiated distribution services, including Price List services	Amended—see clause 21 and Table 3 in Part C of the revised Negotiating Framework
7	Amendment to sections 14 and 20, removing reference to ETSA Utilities' internal dispute resolution process. The amendment must, consistent with clause 6.7.5(c)(6) of the NER, provide that all disputes are to be dealt with by the AER in accordance with Part 10 of the NEL and Part L of the NER	References to internal dispute resolution procedures removed. See clause 15 and 24
8	Amendment to part C or elsewhere in the negotiating framework as appropriate, such that consistent with clause 6.7.5(c)(7) of the NER, arrangements are specified for the payment of ETSA Utilities' reasonable direct expenses in processing an application to provide negotiated distribution services, including Price List services	See clause 25 of the revised Negotiating Framework
9	Amendment to part C or elsewhere in the negotiating framework as appropriate, such that consistent with clause 6.7.5(c)(8) of the NER, ETSA Utilities must determine the potential impact on other distribution network users of the provision of all negotiated distribution services, including Price List services	Amended—see clause 23
10	Amendment to section 16.1, removing reference to incurred and/or committed costs in relation to the termination of negotiations that are beyond those captured by clause 6.7.5(c)(7) of the NER.	Clause removed

3

We do everything in our power to deliver yours

Control mechanism for standard control services

3

CONTROL MECHANISM FOR STANDARD CONTROL SERVICES

In this chapter of the Revised Proposal, ETSA Utilities responds to the AER's Draft Determination on the control mechanism to apply to standard control services.[15]

The control mechanism proposed by the AER is similar to the Weighted Average Price Cap (WAPC), initially defined by the AER in its Framework and approach paper[16]. The proposed control mechanism has been modified to incorporate some of the detailed changes that ETSA Utilities advocated in its Original Proposal. It also incorporates some further changes proposed by the AER.

In the Original Proposal, ETSA Utilities proposed a formula to demonstrate compliance with the side constraint on tariff classes, which was similar in structure to the WAPC. The AER has accepted this arrangement.

ETSA Utilities has two concerns with regard to the implementation of the proposed control mechanism, as follows:

- retention of the $(1+D_t)$ term in the WAPC and side constraint formulae, to accommodate any foregone revenue adjustment under Part B of the DMIS scheme: and
- the need for a mechanism to recover working capital, required to fund Transmission Use of System (TUoS) payments.

15 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, Chapter 4.

16 Final Framework and approach paper—ETSA Utilities 2010–15, AER, 15 November 2008, p56.

3.1

RULE REQUIREMENTS

In clause 6.12.1 of the Rules there are a number of constituent decisions that must be made by the AER as part of each distribution determination. Those decisions pertaining to the control mechanism for standard control services include:

- the control mechanism (including the *X* factor) for standard control services (to be in accordance with the relevant Framework and approach paper) (clause 6.12.1(11));
- how compliance with a relevant control mechanism is to be demonstrated (clause 6.12.1(13));
- a decision on the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another (including any applicable restrictions) (clause 6.12.1(17)); and
- how ETSA Utilities is to report to the AER on its recovery of Transmission Use of System (TUoS) charges for each regulatory year of the regulatory control period, and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges (clause 5.12.1(19)).

3.2

ETSA UTILITIES' ORIGINAL PROPOSAL

In its Original Proposal, ETSA Utilities proposed the following modifications to the control mechanism for standard control services, which the AER had described in the Framework and approach paper.

3.2.1
Scope of the WAPC

The scope of the WAPC would be extended to include certain 'variable' metering services, which would be treated as standard control services, rather than as alternative control services under a separate WAPC.

3.2.2
The WAPC formula

Detailed changes would be made to the WAPC formula in order to provide:

- a pass through term in percentage form;
- an *X* factor X_t, which could vary in different years of the determination;
- the inclusion of EDPD amounts in the building block analysis, rather than in the WAPC formula; and
- a clarification of the definition of CPI_t.

3.2.3
Tariff side constraints

The formulation of the test to apply to side constraints on the price movement of standard control services was proposed by ETSA Utilities. The five tariff classes, to which it was proposed that the side constraint would apply, were nominated. ETSA Utilities also undertook to submit tariffs consistent with clause 9.29.5(d) of the transitional Rules, which limits the maximum increase in the fixed supply charge component for small customers to $10 per annum.

3.2.4
Reasonable estimates

A reasonable estimates approach was proposed by ETSA Utilities, to permit possible changes to tariff structures under the WAPC during the 2010–15 regulatory control period. This approach was the same as that currently employed by the NSW DNSPs.

3.2.5
TUoS recovery

ETSA Utilities proposed an approach to reconcile the recovery of the TUoS payments to ElectraNet and the avoided TUoS payments made to embedded generators. That reconciliation differed in two material respects from the procedure that the AER had at that time proposed for the draft NSW Determinations:[17]

- to reduce price fluctuations, it made use of the most recently available estimated volumes for the current year (t-1) in the reconciliation, rather than relying solely upon audited (t-2) volumes; and
- provision was made in the reconciliation for interest on the working capital needed to support the timing difference between the payments made to ElectraNet and others, and the subsequent recovery of those funds from customers.

3.2.6
Assigning customers to tariff classes

In its Original Proposal, ETSA Utilities described in detail the process it currently employs for the assignment and reassignment of customers to tariff classes. This was considered to align with the requirements of clause 6.18.4 of the Rules.

ETSA Utilities proposed that, in the absence of an Ombudsman scheme equivalent to that in NSW, the AER should become the external body to review small customer objections to ETSA Utilities' tariff assignment/reassignment decisions.

17 Draft decision—New South Wales draft distribution determination 2009–10 to 2013–14, AER, 21 November 2008, Appendix I.

3.3

THE AER'S DRAFT DETERMINATION

Chapter 4 of the AER's Draft Determination contains the following decisions on the control mechanism for standard control services, in response to ETSA Utilities' proposals and other considerations. The matter of assigning customers to tariff classes is dealt with in chapter 2 of the Draft Determination.

3.3.1
Scope of the WAPC

In the Draft Determination the AER did not accept ETSA Utilities' proposal that 'variable' metering services should be treated as standard control services, rather than alternative control services (see chapter 2 of this Revised Proposal). It therefore did not accept ETSA Utilities' proposal to extend the scope of the WAPC to include those metering services. The AER maintained that those metering services should be classified as alternative control services.

3.3.2
The WAPC formula

The following detailed changes were made to the WAPC formula in the Draft Determination:

- a pass through term in percentage form proposed by ETSA Utilities was accepted;
- an *X* factor X_t, which could vary in different years of the regulatory control period as proposed by ETSA Utilities was accepted;
- the inclusion of EDPD amounts in the building block analysis, rather than in the WAPC formula as had been proposed by ETSA Utilities, was not accepted;
- the $(1+ D_t)$ term was deemed to be redundant by the AER and removed; and
- the AER proposed an alternative expression for the definition of CPI_t.

In the Draft Determination, the AER also proposed to incorporate an adjustment related to the actual expenditure against the Demand Management Incentive Allowance approved by ESCoSA, as a component of the EDPD carryover amount.

3.3.3
Tariff side constraints

The AER accepted ETSA Utilities' proposed formulation of the side constraint to apply to the price movement of standard control services tariff classes. Detailed changes were also proposed to this formula, to maintain consistency with the WAPC formula. Those changes were:

- the $(1+ D_t)$ term was deemed to be redundant by the AER and removed; and
- the AER proposed an alternative expression for the definition of CPI_t.

The AER also accepted ETSA Utilities' undertaking to submit tariffs consistent with clause 9.29.5(d) of the Rules.

3.3.4
Reasonable estimates

The AER accepted ETSA Utilities' proposed reasonable estimates approach, to permit possible changes to tariff structures to be managed under the WAPC during the currency of the 2010–15 regulatory control period.

3.3.5
TUoS recovery

The AER accepted ETSA Utilities' proposal for reconciling TUoS over and under recovery amounts, using the most recent (t-1) estimates of TUoS recovery.

The AER did not accept ETSA Utilities' proposed provision for funding the timing difference between TUoS related payments and the subsequent recovery of those funds from customers.

3.3.6
Assigning customers to tariff classes

The AER reviewed the information contained in ETSA Utilities' Original Proposal and the Tariff Manual concerning the assignment and reassignment of customers to tariff classes. These were assessed for consistency with clause 6.18.4 of the Rules, which specifies the principles that the AER must have regard to in formulating provisions of a distribution determination governing the assignment and reassignment of customers to tariff classes.

The AER considered that the provisions concerning the internal review of tariff assignment decisions needed to be set out in the Tariff Manual or equivalent procedure.

On the matter of external review, it noted that if a jurisdictional energy Ombudsman scheme is established to review such disputes, ETSA Utilities would be required to notify customers of this review mechanism, as an alternative to review by the AER under Part 10 of the NEL.

The AER's procedure for assigning customers to tariff classes was set out in Appendix B of the Draft Determination.

3.4

ETSA UTILITIES' RESPONSE TO THE AER'S DRAFT DETERMINATION

ETSA Utilities notes the AER's confirmation that a WAPC will be applied to its standard control services during the 2010–15 regulatory control period.

3.4.1 Scope of the WAPC

Chapter 2 of this Revised Proposal covers the classification of services. In chapter 2, ETSA Utilities has incorporated the AER's Draft Determination that 'variable' metering services should be classified as alternative control services.

ETSA Utilities has also incorporated the AER's Draft Determination that the scope of the WAPC should not be extended to include those metering services as standard control services.

3.4.2 The WAPC formula

In the Draft Determination, the AER set out the formula for the WAPC in section 4.6.1. In this Revised Proposal, ETSA Utilities:

- has incorporated the AER's formulation of the pass through term in a percentage form;
- has incorporated the AER's formulation of an X factor which could vary in different years of the regulatory control period;
- has incorporated the inclusion of EDPD amounts in the WAPC formulation; and
- has incorporated the AER's alternative form of expression proposed for the definition of CPI_t.

ETSA Utilities has not however, incorporated the modification of the WAPC formula by removing the $(1+D_t)$ term. Whilst the DMIA expenditure allowance has been included as an adjustment to ETSA Utilities' operating costs, any foregone revenue adjustment under Part B of the scheme needs to be accommodated using this factor.

3.4.3 Adjustment for demand management expenditure under the EDPD

The AER has proposed to include an adjustment related to the Demand Management Incentive Allowance approved by ESCoSA under the EDPD. That adjustment is proposed to form a component of the EDPD adjustment term in the WAPC.[18]

Part A of the EDPD sets out ESCoSA's statement of reasons. In section 4.4.1 of Part A, ESCoSA stated that any over-spend of the demand management allowance would be at ETSA Utilities' cost and any underspend would be returned to customers during the 2010–2015 regulatory period.[19] However, Part B of the EDPD, which sets out the price determination, does not provide a tariff adjustment mechanism for any underspend of the demand management allowance.

Clause 9.29.5 of the Rules sets out the jurisdictional derogations and transitional arrangements relating to the transition from the EDPD made by ESCoSA, to the distribution determination to be made by the AER. Clause 9.29.5 requires the AER to make provision for certain matters in its distribution determination, including:

- incorporation of transitional arrangements to take into account the change from a pre-tax to a post-tax revenue model (clause 9.29.5(b)(1));
- allowance for ETSA Utilities to carry forward impacts associated with the calculation of Maximum Average Distribution Revenue under the price determination to the 2010/11 and 2011/12 regulatory years (clause 9.29.5(b)(2));
- for the efficiency benefit sharing scheme under the AER's distribution determination to be consistent with ESCoSA's statement of regulatory intent (clause 9.29.5(c));
- a side constraint to tariffs for small customers (clause 9.29.5(d) and (e)); and
- for any reduction in transmission network charges as a consequence of a regulatory reset to be paid to all customers (clause 9.29.5(f)).

The EDPD does not make provision for an adjustment to revenues relating to any under expenditure of the EDPD's demand management allowance. In particular, actual expenditure relative to the demand management allowance has no impact that is associated with the calculation of the Maximum Average Distribution Revenue. Therefore, ETSA Utilities does not consider that clause 9.29.5(b)(2) of the transitional provisions provides a basis for the AER to adjust tariffs in the 2010–15 regulatory control period to reflect any underspend on the EDPD's demand management allowance.

ETSA Utilities has not identified a relevant basis which would permit the AER to provide for an adjustment to revenues relating to any underspend of the EDPD's demand management allowance. Notwithstanding this, and noting the comments of ESCoSA in Part A of the EDPD, ETSA Utilities has incorporated in this Revised Proposal the inclusion of an 'unders/overs adjustment related to the demand management allowance approved by ESCOSA as an additional component of the EDPDt term' as proposed by the AER. This should not be taken as ETSA Utilities accepting the reasons given by the AER as to the basis for the inclusion of such an adjustment.

18 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p 51.

19 ESCoSA, 2005–2010 Electricity Distribution Price Determination: Part A Statement of Reasons, April 2005, p 60.

3.4.4
Tariff side constraints

The AER has set out the side constraint formula in section 4.6.2 of the Draft Determination.

In this Revised Proposal, ETSA Utilities has incorporated the AER's formulation of the test to apply to side constraints on the price movement of standard control service tariff classes, noting there are minor differences between this formula and that proposed by ETSA Utilities in relation to the removal of the $(1+D_t)$ term and the alternative definition of CPI_t.

ETSA Utilities has also incorporated the AER's alternative form of expression proposed for the definition of CPI_t.

For the reasons set out in section 3.4.2, ETSA Utilities believes the $(1+D_t)$ term needs to be retained in this formula.

ETSA Utilities also confirms its undertaking to submit tariffs which are consistent with clause 9.29.5(d) of the Rules.

3.4.5
Reasonable estimates

In this Revised Proposal, ETSA Utilities has incorporated the AER's reasonable estimates approach set out in Appendix E of the Draft Determination. This will permit possible changes to tariff structures during the 2010–15 regulatory control period.

3.4.6
TUoS recovery

ETSA Utilities has incorporated the AER's proposal for reconciling TUoS over and under recovery amounts using the most recent (t-1) estimates of TUoS recovery as set out in Appendix F of the Draft Determination.

ETSA Utilities has not incorporated the AER's decision not to make provision in the TUoS overs and unders account for an interest cost adjustment for the delay between when TUoS related payments are made, and when they are subsequently recovered from customers.

The AER stated in the Draft Determination that:

> *'The AER considers that the type of cash flow issue identified by ETSA Utilities is a one–off effect which would have occurred over the first 45 days of ETSA Utilities' operation in the NEM. ETSA Utilities operates on a continuous basis, and TUOS payments from customers can be used to offset TUOS payments to ElectraNet, even where the payments are not referencing the same period. The AER therefore does not accept the additional interest charge because this one–off effect has already occurred.'*[20]

ETSA Utilities does not agree with the rationale put forward by the AER for not providing for an interest cost adjustment. It is obliged on a monthly basis to make payments to ElectraNet and others in respect of TUoS and avoided TUoS charges before recouping these funds from customers over the ensuing four months. As described in Attachment C.6 of ETSA Utilities' Original Proposal, there is an average period of approximately 28 days between the payment and receipt of these amounts[21]. This report has been resubmitted as Attachment C.1 to this Revised Proposal.

ETSA Utilities is therefore obliged to maintain working capital to finance the early payment of TUoS charges on a continuous basis. The necessity of working capital for business operations is recognised in other aspects of the regulatory revenue modelling.

ETSA Utilities believes that the AER's Draft Determination not to permit the recovery of the working capital for the within period financing of TUoS charges is inconsistent with the following:

- 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 EDPD, where this financing cost was recognised by ESCoSA and formed part of the ETSA Utilities' revenue allowance.

No alternative provision is made elsewhere in the AER's modelling for the working capital to cover this financing cost. ETSA Utilities therefore reiterates its proposal that the within period financing of TUoS charges should be factored into the TUoS under and over recovery calculation.

20 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p 52.

21 Attachment C.6—Treatment of TUoS recovery, ETSA Utilities, May 2009.

3.5

REVISED PROPOSAL

The following material replaces or supplements that contained in chapter 4 of ETSA Utilities' Original Proposal.

3.5.1 The WAPC and side constraint formula

The AER has proposed a number of detailed changes to the WAPC formula for standard control services. With one exception, ETSA Utilities has incorporated these minor changes. However, ETSA Utilities believes it is inappropriate to modify the WAPC formula by removing the $(1+D_t)$ term.

The DMIA expenditure allowance has been included as an adjustment to ETSA Utilities' operating costs spread evenly over the period, however there is no requirement as to when the expenditure occurs over the period. In fact, the only assessment of under expenditure or expenditure not approved, must wait until the end of the 2010–15 period. Accordingly, the $(1+D_t)$ term in the WAPC is not applicable to the actual DMIA expenditure.

On the other hand, approved foregone revenue relating to loss of sales from a project implemented under the DMIS relates to each year that the project effectively operates. Therefore, ETSA Utilities can see no reason that the $(1+D_t)$ term should not be retained and applied to the approved foregone 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 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.[22]

Further, ETSA Utilities proposed in its Original Proposal that the recognition of foregone revenue should not be limited to demand management projects under the DMIS, but should be extended to approved foregone revenue associated with any demand management project, which is undertaken over the period. ETSA Utilities remains convinced that recognition of foregone revenue associated with all demand management projects is essential to overcome the inherent barrier if such adjustment is not incorporated in the WAPC. ETSA Utilities describes the reasons supporting this position in section 9.4 of this Revised Proposal.

Accordingly, ETSA Utilities advocates that the $(1+D_t)$ term is not made redundant as proposed by the AER, but be retained to adjust for approved foregone loss of revenue associated with all demand projects undertaken within the period.

For the same reasons, ETSA Utilities also believes the $(1+D_t)$ term needs to be retained in the side constraint formula.

3.5.2 Assigning customers to tariff classes

The AER concluded in the Draft Determination not to permit 'variable' metering services to be classified as standard control services. ETSA Utilities has incorporated this aspect of the AER's Draft Determination in this Revised Proposal, and, as a consequence, the tariff classes need to be changed from those nominated in ETSA Utilities' Original Proposal.

The practical limitations and preferences concerning the way in which tariffs may be grouped into classes are as follows:

- A side constraint which is applied to a tariff with a very small number of customers becomes akin to a single customer constraint, particularly if one customer is dominant. This can restrict price movement to the point that the side constraint effectively applies to individual customers. This situation would apply to ETSA Utilities' sub-transmission and zone substation customers. All sub-transmission and zone substation customers have therefore been grouped together as a single tariff class for the purpose of side constraint compliance.
- Customers are expected to migrate between tariffs where it is financially advantageous for them to do so. Indeed ETSA Utilities' tariff strategy will be promoting such movement, for example, from the inclining block business single-rate to the more cost reflective two rate tariff or demand tariff. In order for this price movement to be facilitated, all LV business customers have been grouped into one tariff class for the purpose of compliance with the side constraint.
- Many residential and small business customers on inclining block tariffs also have controlled load off peak hot water for which the consumption and price is separately itemised on their bill. In the interests of simplicity, these customers could, and should, be covered by a single side constraint on their price movement. Therefore the controlled load and inclining block tariffs of these customers have been grouped to form a single tariff class. This will also facilitate a simple transition for customers shifting from single-rate with controlled load, to two-rate, where that option is available.

22 AER, *Framework and Approach Paper: ETSA Utilities 2010–15—Final*, November 2008, p 95.

- The 'fixed' metering component associated with energy data services for Type 6 meters has been included within the tariff classes of Low voltage business and Residential customers.

The tariff groups now proposed for the assessment of compliance with the side constraint are as follows:

1. Major business;
2. High voltage business;
3. Low voltage business (including unmetered supplies); and
4. Residential.

These groupings are considered to be appropriate in addressing the potential issues described above, whilst allowing the maximum flexibility for ETSA Utilities to efficiently price its standard control services, and to permit customers to readily move between tariffs.

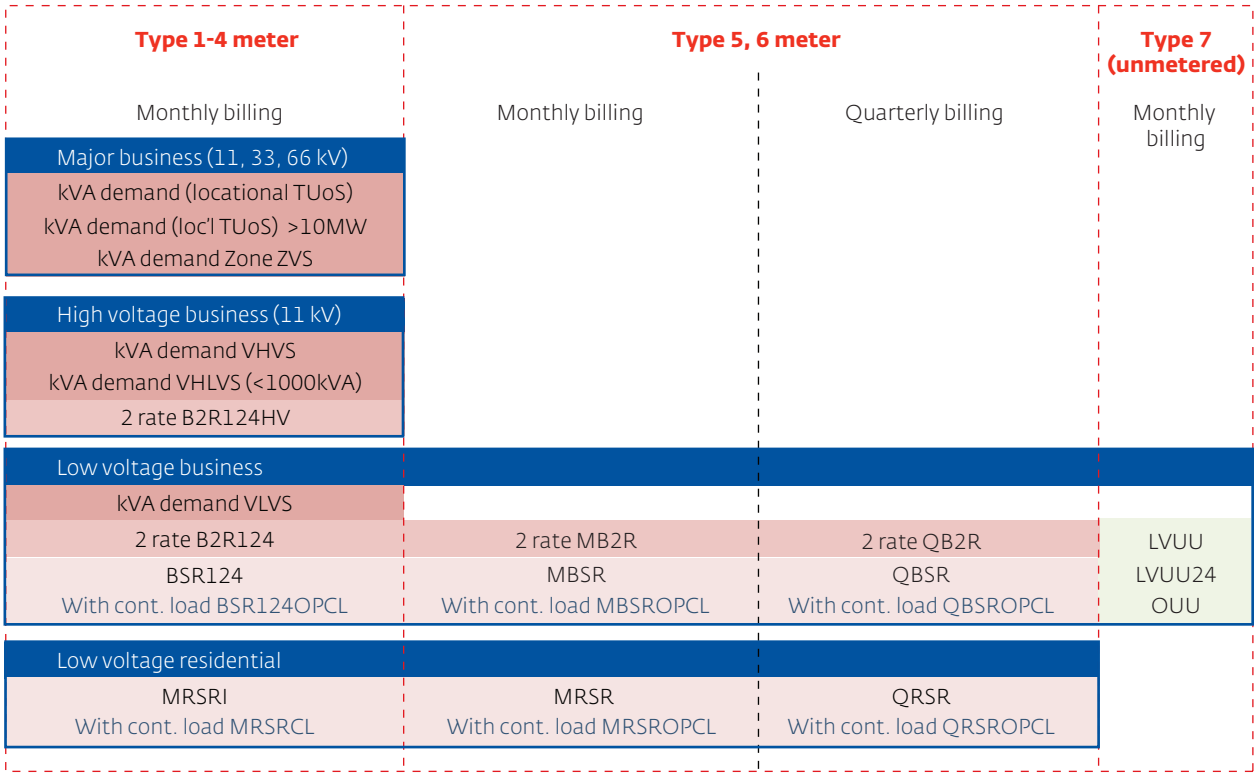
ETSA Utilities has illustrated the grouping of its individual tariffs into tariff classes in Figure 3.1 using red outlines. This illustration does not include within the current range some obsolete and legacy tariffs, most of which are expected to be able to be withdrawn as customers migrate to standard tariffs before the 2010–15 regulatory control period. It should also be noted that metering tariff components covering the aspects of Energy Data Services and Meter Provision have been included as a separate tariff class.

ETSA Utilities notes, and has incorporated in this Revised Proposal the AER's requirements concerning the assignment of tariffs to customers set out in Appendix B of the Draft Determination.

ETSA Utilities will incorporate those requirements into its documented procedure on tariff assignment and submit the revised document to the AER with its Pricing Proposal.

Chapter 4 of this Revised Proposal, which deals with the control mechanism for alternative control services, notes that the Draft Determination does not set out the AER's decisions and reasons for decisions on a number of issues, including tariff components. Given this, and as discussed in section 4.3 of Chapter 4, ETSA Utilities anticipates that the AER and ETSA Utilities will need to consult closely in the lead up to the AER's Final Decision on matters related to alternative control services, such as tariff classes.

Figure 3.1: ETSA Utilities' proposed tariff classes



3.5.3 Recovery of Transmission Use of System charges

As noted in section 3.4.6 above, ETSA Utilities will continue to pay TUoS charges to ElectraNet throughout the course of the 2010–15 regulatory control period. It will also be required to continue paying avoided TUoS charges to embedded generators, under clause 5.5(h)-(j) of the Rules. These charges will be recovered from retailers and end use customers in addition to DUoS charges for the use of ETSA Utilities' network.

There is a significant difference between the timing of the payments for TUoS, which are made early in each month to ElectraNet and embedded generators, and the recovery of those amounts from customers. ETSA Utilities is obliged to finance this working capital requirement on an ongoing basis and is reasonably entitled to expect that this funding cost will be met as part of the regulatory revenue requirement.

Attachment C.6—Treatment of TUoS recovery—to ETSA Utilities' Original Proposal set out the reasoning behind, and an appropriate process to estimate this funding cost. In relation to this specific issue, ETSA Utilities refers to and relies upon Attachment C.6 of its Original Proposal.

Revised Proposal

On the arrangements associated with standard control services, ETSA Utilities' Revised Proposal has incorporated the following:

- *retention of the $(1+D_t)$ term in the WAPC and side constraint formulae, to accommodate approved foregone revenue adjustments associated with demand management projects undertaken within the period;*
- *alteration of the tariff classes from the Original Proposal, to allow the 'variable metering services' charges to be recovered as alternative control services; and*
- *a change to the provisions of the AER's Draft Determination, to permit recovery of the cost of funding the working capital occasioned by the timing difference between when TUoS and related payments are made and when they are recovered from customers.*

A revised tariff assignment procedure reflecting the AER's requirements will be submitted with ETSA Utilities' Pricing Proposal.

4

We do everything in our power to deliver yours

Control mechanism for alternative control services

4

CONTROL MECHANISM FOR ALTERNATIVE CONTROL SERVICES

In this section of the Revised Proposal, ETSA Utilities responds to the AER's Draft Determination on the control mechanism to apply to alternative control services.[23]

In the Framework and approach paper, the AER indicated that its likely approach to the classification of services would be to classify certain variable standard small customer metering services and exceptional cases of large customer metering services as alternative control services. The Framework and approach paper indicated that these services were to be the subject of a separate building block determination and a WAPC form of price control, similar to that proposed to apply to standard control services.[24]

In the Original Proposal, ETSA Utilities expressed concern with the additional administrative requirements and system changes that would accompany this classification of services. ETSA Utilities agreed that these metering services could be unbundled, but proposed their classification as standard control services, subject to a single WAPC.

In its Draft Determination, the AER has confirmed that the alternative control classification of services would apply to 'variable' and 'exceptional' metering services, as defined in the Framework and approach paper. It also confirmed that a separate WAPC form of price control would apply to these services in the 2010-15 regulatory control period.

23 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, Chapter 4.

24 Final Framework and approach paper—ETSA Utilities 2010-15, AER, November 2008.

4.1

RULE REQUIREMENTS

In clause 6.12.1 of the Rules, there are a number of constituent decisions that must be made by the AER as part of a distribution determination. The decisions pertaining to the control mechanism for alternative control services include:

- a decision on the control mechanism for alternative control services (to be in accordance with the relevant Framework and approach paper) (clause 6.12.1(12); and
- a decision on how compliance with a relevant control mechanism is to be demonstrated (clause 6.12.1(13).

4.2

ETSA UTILITIES' ORIGINAL PROPOSAL

In the Original Proposal, ETSA Utilities expressed concern with the additional set-up and ongoing administrative costs which would accompany the classification of variable standard small customer metering services and the exceptional cases of large customer metering services as alternative control services. Those costs related to the information requirements for a separate building block determination, and separate accounting, reporting and price approval arrangements. ETSA Utilities was concerned with the capability of its existing accounting and billing systems to support the changed requirements and the potential cost of modifying these systems to comply with the requirement to provide the relevant metering services as alternative control services. Moreover, there was the overriding issue of whether making the necessary changes in time to introduce the billing of separate tariff components by 1 July 2010 would be practicable.

Primarily for these reasons, ETSA Utilities proposed a simplified arrangement whereby the 'variable' and 'exceptional' metering service components would be classified as standard control services. It was proposed that the associated metering tariffs would be treated in the same manner as tariffs for the use of the network and be included under the WAPC form of price control.

ETSA Utilities also proposed that the metering tariffs would be grouped within a separate tariff class, for the purpose of demonstrating compliance with the side constraint on standard control services.

4.3

THE AER'S DRAFT DETERMINATION

The AER's Draft Determination rejected ETSA Utilities' proposal to extend the scope of the WAPC to include certain metering services, to be treated as standard control services. It maintained that those metering services should be classified as alternative control services and should be the subject of a separate building block PTRM and WAPC.

The AER determined that the WAPC formula to apply to these alternative control services was the same as that set out in the Framework and approach paper.[25] For brevity, the associated formula is not repeated in this chapter of the Revised Proposal.

The AER's Draft Determination states that the AER will assess the building block components as part of its final distribution determination for ETSA Utilities based on ETSA Utilities' Revised Proposal and submissions from interested parties.[26] As set out below, ETSA Utilities has incorporated in this Revised Proposal, the AER's Draft Determination to classify variable standard small customer metering services and exceptional cases of large customer metering services as alternative control services.

ETSA Utilities has also incorporated in this Revised Proposal, the AER's Draft Determination that there should be a separate building block PTRM and WAPC in respect of alternative control services.

The Draft Determination does not set out the AER's decisions and reasons for decisions on issues such as: the building block components; tariff components; forecast customer numbers; or relevant X factors in respect of alternative control services.[27] Without commenting on this matter further at this stage, ETSA Utilities notes that the AER's Draft Determination on alternative control services may not satisfy the requirements of the Rules relating to draft determinations, in particular those in clauses 6.12.1 and 6.12.2 of the Rules. ETSA Utilities therefore anticipates that the AER and ETSA Utilities will need to consult closely in the lead up to the AER's Final Determination on these issues.

25 Final Framework and approach paper, ETSA Utilities, AER, November 2008, appendix D, p 130.

26 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 427.

27 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 427.

4.4

ETSA UTILITIES' RESPONSE TO THE AER'S DRAFT DETERMINATION

For the reasons set out in section 2.4 of this Revised Proposal, ETSA Utilities does not consider that the AER has given the appropriate weighting to the factors it considered in classifying variable standard small customer metering services and exceptional cases of large customer metering services as alternative control services.

Notwithstanding that ETSA Utilities considers this decision by the AER to be inappropriate, it has had further opportunity to assess different options and determine whether it would be possible to make the necessary changes to its systems and processes to implement the AER's requirements before 1 July 2010. ETSA Utilities has now concluded that these arrangements could be made utilising existing systems by that date, but that an ongoing comprehensive solution requires systems changes that can only be implemented after the start of the next regulatory control period (ie July 2010).

It must be noted that billing system constraints will require an interim arrangement with a small number of initial metering tariff components. ETSA Utilities had developed six operationally practical cost reflective alternative control services meter provision tariff components, which will at least initially need to be recovered through three meter provision tariffs. This arrangement will allow for the implementation of the AER's requirements by 1 July 2010, but the existing network billing system must be modified to remove this limitation during the first year of the next regulatory control period.

Accordingly, while not agreeing with the reasons for the AER's Draft Determination to classify variable standard small customer metering services and exceptional cases of large customer metering services as alternative control services, in this Revised Proposal, ETSA Utilities has incorporated the AER's classification of these metering services as alternative control services.

Attachment D.1 describes ETSA Utilities' compliance with the AER's classification of metering services as alternative control services.

4.5

REVISED PROPOSAL

ETSA Utilities has incorporated the AER's classification of certain metering services as alternative control services, subject to the WAPC set out in section 17.3 of the Draft Determination. ETSA Utilities has incorporated the AER's Draft Determination that ETSA Utilities will demonstrate compliance with this control mechanism by providing details of the proposed metering tariffs as part of its annual pricing proposal.

The additional costs associated with the implementation and ongoing maintenance of this arrangement have been factored into the operating cost forecasts for alternative control services in this Revised Proposal.

4.5.1 Minor changes to the WAPC formula for alternative control services

The AER proposed a number of changes to the WAPC formula set out in the Framework and approach paper for standard control services. It did not make the same changes to the corresponding alternative control services formula.[28] The relevant changes to the alternative control services formula, to align the two, are as follows:

- An X factor X_t, which could vary in different years of the regulatory control period; and
- An alternative expression was proposed for the definition of CPI_t.

Revised Proposal

To preserve consistency with the WAPC proposed for standard control services, ETSA Utilities has incorporated the above minor changes to the formula for alternative control services in this Revised Proposal.

4.5.2 Reasonable estimates approach to permit tariff changes

In section 4.4, ETSA Utilities referred to the need to adopt an interim arrangement with a limited number of tariff components because of billing system limitations.

It is therefore likely that ETSA Utilities may need to make changes to the metering tariffs during the course of the regulatory control period in order to improve the cost reflectivity of these tariffs. This may require the introduction of an expanded range of tariffs.

Unless the reasonable estimates approach to tariff changes in Appendix E of the AER's Draft Determination could also be applied to alternative control services, such refinement of the metering tariffs would not be possible during the course of the regulatory control period.

28 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p421.

Revised Proposal
ETSA Utilities has therefore incorporated into this Revised Proposal the reasonable estimates approach for alternative control services, to facilitate cost reflective tariffs during the regulatory control period.

4.5.3 Meter customer exit fee

In section 2.5.1 of this Revised Proposal, ETSA Utilities has proposed a meter customer exit fee, for inclusion as an alternative control service. That fee would apply where an existing ETSA Utilities meter at a customer premises was removed and replaced with a meter supplied by another metering provider. ETSA Utilities proposes that such fee would equate to the sum of:

- the average written-down value of the customer's meter, which would represent the loss to ETSA Utilities occasioned by the replacement; and
- the operating cost incurred as a result of the meter change-over not otherwise recovered.

By recognising the asset component of this fee as a capital contribution under the alternative control service pricing arrangements, the integrity of the alternative control services building block model would be preserved and the capital costs associated with meters removed from the asset base would not continue to be recouped from the remaining customers.

Revised Proposal
Notwithstanding that ETSA Utilities considers the AER's Draft Determination to be inappropriate with regard to classifying variable standard small customer metering services and exceptional cases of large customer metering services as alternative control services, ETSA Utilities has incorporated the AER's classification of certain metering services as alternative control services.

5

We do everything in our power to deliver yours

Peak demand and sales forecasts

5

PEAK DEMAND AND SALES FORECASTS

In this chapter of the Revised Proposal, ETSA Utilities considers the AER's Draft Determination on the peak demand and sales forecasts, which were used to determine the revenue requirements and distribution price path for the 2010–15 regulatory control period.[29]

ETSA Utilities' Original Proposal contained three discrete forecasts. These were:

- *Sales forecast:* This is a forecast of total sales on a per annum basis[30] and was developed by economic consultant National Institute of Economic and Industry Research (NIEIR), with additional supporting analysis undertaken by Maunsell Australia Pty Ltd (Maunsell). A forecast of customer numbers is a component of the sales forecast;
- *Global peak demand forecast:* This uses the same economic assumptions as the sales forecast. Its primary function is to check the overall consistency of the spatial peak demand forecast; and
- *Spatial peak demand forecast:* This forecast is used to derive the growth related capital expenditure at various locations throughout the network and a component of the operating expenditure.

The forecasts all used the most current available information at the time of submission, on demand and sales trends, the economic outlook and Government energy efficiency/greenhouse policy measures and programs. It is noted that the timing of the May 2009 Federal Budget meant that the effect of some of the associated energy efficiency/greenhouse initiatives were taken into account with limited available detail as to their impact on sales. Initiatives such as the green loan scheme and energy efficient homes package have since been clarified resulting in some modifications to ETSA Utilities' forecasts in respect to the latter initiative.

The AER obtained consultancy assistance to review ETSA Utilities' peak demand and sales forecasts.[31,32] In the Draft Determination, the AER:

- accepted ETSA Utilities' customer number forecast as realistic, based on MMA advice. However the AER did not accept ETSA Utilities' overall sales forecast as reasonable. Instead, the AER substituted an energy sales forecast developed by the AEMO, for that which ETSA Utilities had provided; and
- accepted ETSA Utilities' global and spatial peak demand forecasts as reasonable, based on advice from the AEMO.

This Revised Proposal provides an updated forecast of the sales volumes, using the most recently available economic outlook and consumption trends, and an updated understanding and analysis of the energy efficiency/greenhouse policy measures. In arriving at this forecast, ETSA Utilities has been provided with extensive consultancy assistance in forecasting economic growth. This research has revealed three plausible economic scenarios, each of which may reasonably reflect future outcomes. A combination of these economic scenarios has been used for the updated forecast.

29 AER, Draft decision—South Australia Draft distribution determination 2010–11 to 2014–15, 25 November 2009, Chapter 6.

30 The sales forecast is built up from the volumes of all components of tariffs, including fixed daily charges, energy charges and demand charges. The principal component of the sales forecast is the energy sales, in GWh.

31 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts.

32 McLennan Magasanik Associates, 21 September 2009, Review of ETSA Utilities customer number forecasts for the 2010 to 2015 price review.

In this Revised Proposal, ETSA Utilities has not updated the following forecasts, since the submission of the Original Proposal, as there has been no material change that would require the revision of:

- *Spatial peak demand forecast:* The lead time associated with the production of the spatial demand forecast precludes its full update and, in any case, the most recent summer period is not yet complete. There has been no significant large customer load development since the submission of the Original Proposal to require incremental update of this forecast and the associated growth related components of the capital and operating expenditure forecasts.

  The spatial peak demand forecast is formulated to represent longer term trends, requiring development of the network. This forecast therefore should not fluctuate with short term variations in economic conditions, such as the modest improvement in economic outlook, which has eventuated since the submission of the Original Proposal.

- *Customer number forecast:* The customer number forecast is a component part of the sales forecast and, in the case of residential customer numbers, has a significant effect on the forecast outcome. The principal driver of the residential customer numbers forecast is the dwelling stock, built up from underlying growth drivers of state population and persons per dwelling. The outlook for these two principal drivers has not changed since the Original Proposal, and so the customer number forecast remains in line with that accepted as reasonable by the AER in the Draft Determination.

5.1

RULE REQUIREMENTS

The principal requirements concerning forecasting are set out in clauses 6.5.6 and 6.5.7 of the Rules. These require the AER to accept a DNSPs operating and capital expenditure forecasts for the purpose of making a regulatory determination, provided that the AER is satisfied that those forecasts reasonably reflect a realistic expectation of demand and suitably address the other operating and capital expenditure criteria.

The DNSPs spatial peak demand forecast determines the need for expansion at different locations within the network, and hence drives a component of both the capital and operating expenditure forecasts.

With the WAPC form of regulatory control, which applies to ETSA Utilities, the sales forecast (which is derived from the customer number and energy sales forecasts) forms an input to the PTRM. This forecast is used to convert the allowable revenue requirement into a price path and X factors.

The Rules do not specifically refer to the sales forecast, except to the extent that it influences forecast operating and capital expenditure. The AER has interpreted clauses 6.5.6 and 6.5.7 as applying to both peak demand (which directly influence capital and operating expenditure) and sales forecasts (which are indirectly related), meaning that it must be satisfied that each of these forecasts reflect a realistic expectation of demand. ETSA Utilities adopts this interpretation of the NER.

5.2

ETSA UTILITIES' ORIGINAL PROPOSAL

The peak demand and energy forecasts, which formed the basis of ETSA Utilities' Original Proposal, were formulated using the most recently available information at the time. Whilst the forecast processes differed in detail, they were based on historical peak demand and sales trends, which were normalised to account for the significant influence of weather.

5.2.1
Economic scenario

Economic consultants within NIEIR developed the forecast of economic drivers, upon which the sales and global peak demand forecasts in ETSA Utilities' Original Proposal were based.[33]

NIEIR's approach to developing this economic forecast involves a number of stages:

- a review of the world economic outlook and the detailed consideration of its interactions with the Australian economy;
- within this world context, the Australian economic outlook is then reviewed and the history and trends of a broad range of well established national economic indicators are determined; and
- the economic outlook for South Australia is then developed as a subset of the national economy, having regard to its unique characteristics.

The principal South Australian economic indicators that NIEIR developed are as follows:

- Gross State Product (GSP);
- business Gross Value Added (GVA) by sector;
- population;
- private consumption expenditure;
- private business investment;
- dwellings investment; and
- government expenditure.

These economic indicators are drivers for the sales and global demand forecast trends. This forecast was prepared in April 2009 and the Original Proposal submitted the following month.

5.2.2
Sales forecast

ETSA Utilities' sales forecast was developed using rigorous processes by NIEIR. Maunsell was engaged to undertake additional supporting analysis of the effect of energy efficiency on appliance consumption. Detailed reports by these consultants were submitted as Attachments to the Original Proposal. Recognising the significant impact of air conditioning usage on both energy and demand, ETSA Utilities also engaged McLennan Magasanik and Associates (MMA) to study trends in the market for air conditioners in South Australia.[34]

33 National Institute of Economic and Industry Research, April 2009, Electrical energy projections for ETSA Utilities in South Australia to 2018–19—A report for ETSA Utilities.

34 McLennan Magasanik Associates, November 2008, Report to ETSA Utilities—The air conditioner market in South Australia.

To enhance the forecast accuracy and facilitate the understanding of underlying trends, historical data was disaggregated into discrete sectoral components.

The forecast of electricity sales volume was based upon a detailed review of the principal underlying drivers of consumption for constituent sectors of the customer base. The starting point for this forecast was weather normalised historic consumption data. Econometric models were then used to project future consumption. Where historical trends could not reflect an influence on future consumption, such as with a range of new energy efficiency initiatives, post-model adjustments were made to the forecast trends.

The residential customer number forecast, which forms a component of the sales forecast, was built up primarily from state population, dwelling starts and persons per dwelling. The number of customers was not specifically modelled for the commercial and industrial sectors, as their consumption was projected from an econometric model of GSP and output by business sector and sub sector.

The sales consumption sectors, their principal drivers, and the post-model adjustment of consumption trends, are summarised in Table 5.1.

The forecast energy sales outcome of the Original Proposal is summarised in Table 5.2. Here, significant differences in forecast growth trends between customer sectors are evident. Over the 2010–15 regulatory control period, overall energy sales were forecast to decline at an average rate of 1.0 percent per annum.

Table 5.1: Principal elements of ETSA Utilities' sales forecast

Customer sector	Consumption driver	Post-model trend adjustment
Residential	• Housing stock • Type of dwelling (new/old) • Appliance stock and usage patterns • Energy consumption per dwelling • Household income • Residential Retail electricity prices • Gas prices • Weather	• Appliance energy efficiency standards • Greenhouse policy decisions
Commercial (subdivided to 9 ASIC categories)	• Economic activity (GSP) • Business sub sector forecast activity • Business Retail electricity prices • Gas prices • Weather	
Industrial (subdivided to 13 ASIC categories)	• Economic activity (GSP) • Business sub sector forecast activity • Business Retail electricity prices • Gas prices	
Major Business	• Economic activity (GSP) • Business sub sector forecast activity • Major Business Retail electricity prices • Gas prices • Significant major projects separately identified	
Controlled load	• Penetration of storage hot water appliances • Energy consumption per appliance • Weather	• Residential Energy Efficiency Standards • Greenhouse policy decisions • Rate of replacement with alternative appliances
Public lighting	• Number of luminaires • Energy usage per luminaire	
Solar photovoltaic energy generation (negative consumption)	• Penetration of solar photovoltaic generator installations • Energy production per installation	• Take-up of Solar Feed-In Tariff • In-house Usage

5.2.3
Global peak demand forecast

The global peak demand forecast used the same basic economic assumptions as the sales forecast and was also developed by NIEIR, whose detailed report was submitted as an Attachment to the Original Proposal.

As the focus of this model is on peak demand, rather than annual consumption, the forecast is constructed from the daily load profiles of four consumption sectors with markedly different peak demand characteristics:

- residential;
- business;
- major business; and
- hot water.

Another distinction between peak demand and sales is that the impact of summer temperature on demand is much greater, whereas the price elasticity of demand is much lower. For comparison with the spatial peak demand, a forecast with a statistically derived 10 percent probability of exceedence (10 percent PoE) was developed. [35]

The primary purpose of this global demand forecast is to check for the overall consistency of the spatial peak demand forecast at numerous locations throughout the network, by comparing global growth with the growth in aggregated spatial demand. This check also serves to demonstrate consistency with the sales forecast, which is based on the same fundamental economic parameters as the global demand forecast. An overall peak demand growth of 3.0 percent was forecast for the 2010–15 regulatory control period, whereas the sales growth was forecast to decline. This progressively worsening average load factor is due to the twin effects of energy efficiency measures (which reduce energy consumption) and increased air conditioning penetration (which increases peak demand).

5.2.4
Spatial peak demand forecast

ETSA Utilities' planning to enable the peak demand to be met and managed is exacerbated by the nature of customers' consumption. This in turn is driven by relatively harsh summer weather conditions and a load profile that is demonstrably peakier than that of DNSPs in other jurisdictions.

Spatial demand forecasting is carried out at three levels within ETSA Utilities' network, as follows:

- *Connection Point forecast:* at each of the 45 points of connection to ElectraNet's transmission network, where electricity is supplied in bulk to ETSA Utilities' distribution network. These bulk supply connection points are at a voltage level of 132 or 66 kV[36];
- *Zone Substation forecast:* at each of the 266 zone substations plus 163 smaller substations, customer substations and regulators in ETSA Utilities' network, where the supply voltage is transformed from subtransmission levels[37] of 66 or 33 kV to the High Voltage levels of 11 or 7.6 kV; and
- *High Voltage Feeder forecast:* of the loading on 1024 individual 11 and 7.6 kV feeders.

These spatial demand forecasts are based on the detailed assessment of trends and anticipated developments at each of ETSA Utilities' zone substations and smaller substations. Because of the peaky nature of the load and limited levels of network security, individual zone substation and feeder level demand forecasts are based on the maximum recorded peak load.

The Transmission Connection Point load forecasts which ETSA Utilities develops by aggregating the zone substation demands, require significant adjustments to be made to accommodate the effects of demand diversity and have been accepted by the AEMO as having a 10 percent PoE, for the purpose of determining power system security and reliability under clause 4.9.1(e) of the Rules.

Table 5.2: ETSA Utilities summary sales volume (excludes major industrial loads)

Customer sector	Sales Volume 2008/09 GWh	Sales Volume 2014/15 GWh	Growth 08/09 to 14/15 %pa
Residential (including solar PV)	3,577	3,130	–2.2%
Commercial (including public lighting)	3,343	3,849	2.4%
Industrial	3,630	3,282	–1.7%
Controlled load	708	334	–11.8%
Total ETSA Utilities	**11,258**	**10,596**	**–1.0%**

35 A forecast is described as having a 50% Probability of Exceedance (PoE) if there is a statistical probability of 50%, that the peak demand will exceed the forecast level. This equates to the likelihood that the forecast will be exceeded on one year in two. Likewise, for a forecast with a 10% PoE, the forecast would be exceeded in 10% of years, or an average of one year in ten.

36 The term transmission network here has the same meaning as in the Rules.

37 In ETSA Utilities' case, subtransmission assets include lines and cables which operate at voltages of 66 and 33 kV and substations and switching stations connected at those primary voltages with a secondary voltage of 11 or 7.6 kV.

ETSA Utilities follows what has been generally accepted as sound utility practice in the development of its spatial demand forecasts.[38] Attachment E.9 to this Revised Proposal describes the spatial demand forecast process in more detail. Summary details of this process were described in chapter 5 of the Original Proposal. The influence of peak demand growth on ETSA Utilities' capital expenditure program was described in detail in chapter 6 of the Original Proposal.

5.3

THE AER'S DRAFT DETERMINATION

The AER engaged the Electricity Supply Industry Planning Council (the Planning Council) to review ETSA Utilities' peak demand and energy sales forecasts and their methodologies. As of 1 July 2009, the Council became part of the Australian Energy Market Operator (AEMO) and most of its functions were assumed by the AEMO, including the report to the AER on ETSA Utilities' peak demand and energy sales forecasts.

The customer number forecast is a component part of the sales forecast. The AER engaged MMA to review ETSA Utilities' customer number forecast and its methodology.

5.3.1 Sales forecast

The two principal components of the sales forecast are the customer number forecast and the energy sales forecast.

Customer numbers forecast

MMA reviewed ETSA Utilities' forecast of customer numbers for both residential and non-residential sectors, for consistency with past trends. MMA considered that both components of the customer number forecast appeared reasonable.[39]

The AER concluded that ETSA Utilities' customer number forecasts provided a realistic expectation of the demand forecast required to achieve the capital and operating expenditure objectives of the Rules. The AER accepted ETSA Utilities' customer number forecast as an appropriate input for the PTRM.[40]

Energy sales forecast

The AEMO developed its own energy sales forecasting model for the purpose of comparison with ETSA Utilities' forecasts. The model employed differed from the model previously used by the Planning Council for forecasting electricity sales in South Australia. The AEMO concluded that as its model and that used by ETSA Utilities delivered very similar outcomes with the same assumptions concerning economic drivers, they operated in a broadly similar manner.[41]

The AEMO reviewed the key forecast drivers underpinning the energy sales forecasts, and made the following significant observations in comparing ETSA Utilities' forecast with their own, which was ultimately adopted by AER:

- *Economic drivers:* a suite of economic indicators prepared by KPMG Econtech in March 2009 forecast lower growth in dwellings investment but much higher growth in the manufacturing and other industry sectors. The AEMO also forecast lower annual retail price increases during the 2010–15 regulatory control period as they did not take into account the effect of the network price increase;[42]
- *Water heating sales:* a forecast of hot water sales based on the most recent five year trend and an assumed life of 20 years for these appliances was used, resulting in a much smaller rate of decline in sales to this sector;[43]
- *Post-model adjustments:* the majority of the post-model adjustments which ETSA Utilities had made to reflect energy efficiency measures in the residential sector were not adopted by the AEMO, as it considered recent historical trends incorporated these measures, and in some cases assumed that the efficiency trends were offset by growth.[44] It is noted that the AER made no reference in its Draft Determination to the South Australian REES scheme, which commenced on 1 January 2009 with targets set by the South Australian Government aimed at achieving significant and broad ranging effects on the adoption of energy efficiency measures in South Australia; and
- *Retail electricity price:* For retail electricity price forecasts, the AER did not accept that the distribution price outcomes arising from ETSA Utilities' energy sales forecast provided an appropriate input for a retail price adjustment.[45] This is despite the AEMO recognising in their report that 'Future retail electricity prices will reflect movements in the underlying wholesale cost of energy, *network charges* and carbon pricing.'

38 Australian Energy Market Commission, 13 May 2009, Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion—Sinclair Knight Mertz, Appendix E.

39 McLennan Magasanik Associates, 21 September 2009, Review of ETSA Utilities customer number forecasts for the 2010 to 2015 price review, pp.15, 17.

40 AER, Draft decision—South Australia Draft distribution determination 2010–11 to 2014–15, 25 November 2009, p.97.

41 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts AEMO, p.48.

42 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts AEMO, pp.19–28.

43 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts AEMO, p.69.

44 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts AEMO, pp.28–37.

45 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts, p.93.

The AEMO energy sales forecast was prepared for three economic growth scenarios.

The AEMO forecast a compound growth in energy sales over the 2010–15 regulatory control period of 2.9 percent for the base scenario, compared with ETSA Utilities' forecast of -0.7 percent for the same period. This overall growth trend includes major industrial loads.

The AER concluded that ETSA Utilities' energy sales forecast did not provide a realistic expectation of the demand forecast required to achieve the capital and operating expenditure objectives of the Rules.[46] The AER did not accept ETSA Utilities' energy sales forecast for input into the PTRM, but instead substituted the energy sales forecast developed by the AEMO.[47]

5.3.2
Peak demand forecasts

Based on the AEMO review, the AER accepted ETSA Utilities' spatial peak demand forecast methodology as reasonable, being supported by the reconciliation of three levels of independent demand forecasts to ensure consistency. The AER also accepted ETSA Utilities' global peak demand model as providing a reasonable forecast, notwithstanding that there were significant differences between the AEMO/ Monash University modelling approach and that employed by ETSA Utilities.

The AER concluded that ETSA Utilities' global and spatial peak demand forecasts provided a realistic expectation of the demand forecast required to achieve the capital and operating expenditure objectives of the Rules.[48]

5.4

ETSA UTILITIES' RESPONSE TO THE AER'S DRAFT DETERMINATION

5.4.1
Economic scenario

In the Draft Determination, the AER rejected ETSA Utilities' sales forecast and substituted a forecast prepared by the AEMO. The economic assumptions underpinning the AEMO's electricity forecasts for the South Australian distribution network were prepared by KPMG Econtech during March 2009. A supplement to the KPMG Econtech forecast incorporated revised assumptions on the electricity price effect, to accommodate changes in mid 2009 to the RET scheme and the CPRS.

KPMG Econtech's forecast was used for the purpose of preparing the AEMO's 2009 Statement of Opportunities. ETSA Utilities notes that this forecast is used for the purpose of determining the adequacy of generation capacity across the NEM.

The AER referred to the South Australian Government' s 2009 Budget, which incorporated a GSP forecast out to 2012/13. ETSA Utilities understands that unlike the Commonwealth Government, the focus of the South Australian Government in its economic forecasting is primarily on employment and labour market outcomes, rather than a broad set of economic indicators. As such, South Australian Treasury do not have their own (econometric or other) model for forecasting South Australian economic outcomes in the two forecast years of the Budget, instead relying on Federal Treasury's forecasts as a platform from which adjustments are made as determined by differing conditions in the State relative to the national average. In the forecast years of a Budget, different local (meaning South Australian) economic conditions form the basis for adjustments away from the national forecasts[49].

ETSA Utilities also notes that the South Australian Government's Budget forecast only covers the first three years of the determination's regulatory period.

ETSA Utilities observes that the most recent ABS measure of the South Australian GSP, of 1.4 percent in 2008–09, differs from both the KPMG Econtech scenarios, upon which the AEMO forecast was based, and NIEIR's forecast, on which ETSA Utilities' sales were based.[50] This outcome serves to reinforce the desirability of improving the forecast accuracy by averaging, an approach which ETSA Utilities has adopted in this Revised Proposal. The economic scenario is described in section 5.5.1.

5.4.2
Sales forecast

The sales forecast comprises two main elements: the customer number forecast; and the energy sales forecast.

Customer number forecast

ETSA Utilities notes and accepts the AER's conclusion that the customer number forecast in the Original Proposal provides a realistic expectation of the demand forecast required to achieve the capital and operating expenditure objectives of the Rules.

Energy sales forecast

ETSA Utilities notes the AER's conclusion that ETSA Utilities' energy sales forecast did not provide a realistic expectation of the demand forecast required to achieve the capital and operating expenditure objectives of the Rules.

ETSA Utilities does not accept the AER's conclusion concerning the energy sales forecast in the Original Proposal, nor does it accept the AER's substitution of the energy sales forecast developed by the AEMO in the PTRM to develop the price path and X factors of the Draft Determination.

46 AER, Draft decision—South Australia Draft distribution determination 2010–11 to 2014–15, 25 November 2009, p.95.

47 AER, Draft decision—South Australia Draft distribution determination 2010–11 to 2014–15, 25 November 2009, p.96.

48 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts, 1 October 2009, p.85.

49 South Australian Budget Statement, p.8–6, footnote (e) to table 8.1.

50 Australian Bureau of Statistics, 22 December 2009, 5220.0—Australian National Accounts: State Accounts, 2008–09 (Reissue).

This Revised Proposal provides an updated energy sales forecast, using updated economic parameters and assumptions wherever fresh information is available. The updated energy sales forecast maintains the same methodology and basic assumptions applied in the Original Proposal, with certain inputs and assumptions updated with current information where this is available. Some of the key updates include:

- current forecasts of economic activity; and
- changes to post-model adjustments incorporating new information and detailed analysis.

ETSA Utilities has significant concerns with the approach used by the AEMO to develop its alternative energy sales forecast. The AEMO reports that it considers the differences in the sales forecasts produced by their model and those of ETSA Utilities:

> *'largely reflect the use of different economic assumptions (including the treatment of energy efficiency savings) rather than effective underlying model differences.'*

ETSA Utilities considers that a reasonable alignment of outcomes for a single economic scenario does not demonstrate that outcomes will remain aligned with the other scenarios, particularly where there are significant differences in the construction of the models and the applied economic drivers.

In order to assist in the resolution of whether the AEMO model used by the AER for determining ETSA Utilities' sales forecast is suitable for that purpose, ETSA Utilities engaged a recognised industry specialist to review the AEMO sales model. A report prepared by Frontier Economics forms Attachment E.1 to this Revised Proposal.[51]

In addition to the concerns that ETSA Utilities has with the appropriateness of the AEMO sales model, ETSA Utilities also does not agree with the post-model adjustments, water heating sales assumptions, customer segmentation and price effects proposed by the AEMO and adopted by the AER. ETSA Utilities engaged MMA to review the post-model adjustments relating to energy efficiency/greenhouse policy measures made by the AEMO and to advise on appropriate adjustments. This report is presented as Attachment E.2 to the Revised Proposal.[52]

Attachment E.3 summarises the review of the sales model, price effects, customer segmentation, hot water sales forecast and post-model adjustments proposed by the AEMO and adopted by the AER. From this review, ETSA Utilities is strongly of the view that the modelling applied by the AEMO is not fit for the purpose of forecasting ETSA Utilities' sales, and can not be relied on to produce reasonable forecasts. In addition, ETSA Utilities has concluded that the AEMO's approach to customer segmentation is inadequate and its analysis of price effects, hot water sales and post-model adjustments are flawed.

5.4.3 Peak demand forecast

ETSA Utilities notes and accepts the AER's conclusions that the spatial and peak demand forecasts in the Original Proposal provide a realistic expectation of the demand forecast required to achieve the capital and operating expenditure objectives of the Rules.

Notwithstanding this acceptance, ETSA Utilities has also obtained advice concerning the Monash demand model from Frontier Economics. The Frontier Economics report on this model is submitted as Attachment E.4 to this Revised Proposal.[53]

ETSA Utilities notes that the half hourly output of the Monash demand model is dependent upon inputs from the AEMO sales model. For the reasons discussed in Attachment E.3, the AEMO sales model is not suitable to be used to forecast ETSA Utilities' sales. The output of the Monash demand model is thereby compromised.

51 Attachment E.1: Frontier Economics, January 2010, Econometric review of the THE AEMO sales models methodology—A Report Prepared for ETSA Utilities.

52 Attachment E.2: McLennan Magasanik and Associates, December 2009, Review of post-model adjustment methodology.

53 Attachment E.4: Frontier Economics, January 2010, Econometric review of the Monash demand model methodology—A Report Prepared for ETSA Utilities.

5.5

REVISED PROPOSAL

In this section of the Revised Proposal, ETSA Utilities provides updates of the energy sales forecast and global demand forecasts, which constituted part of the Original Proposal.

Some of the desirable characteristics of forecasting models have been mentioned in Attachment E.1, in connection with the review of the AEMO sales model's methodology. These best practice forecast attributes are set out in section 5.5.3, and NIEIR's approach to modelling the sales forecast is demonstrated to fulfil all of these requirements.

Revised forecasts have not been submitted for spatial demand or for customer numbers. The forecasts of these quantities in the Original Proposal were accepted by the AER as reasonable and there has been no material change in the intervening period, which would necessitate their revision:

- in the case of the spatial peak demand forecast, the time required to produce the spatial demand forecast precludes its full update, and there has been no recent large customer load development; and
- the principal driver of the residential customer numbers forecast is population and persons per dwelling which determine the dwelling stock requirement. These drivers have not changed materially since the Original Proposal.

Accordingly, ETSA Utilities has not updated these forecasts in the Revised Proposal.

A revised reconciliation of the global and spatial peak demand forecasts in included in section 5.5.10, to demonstrate the overall consistency of the forecasts and their underpinning economic assumptions.

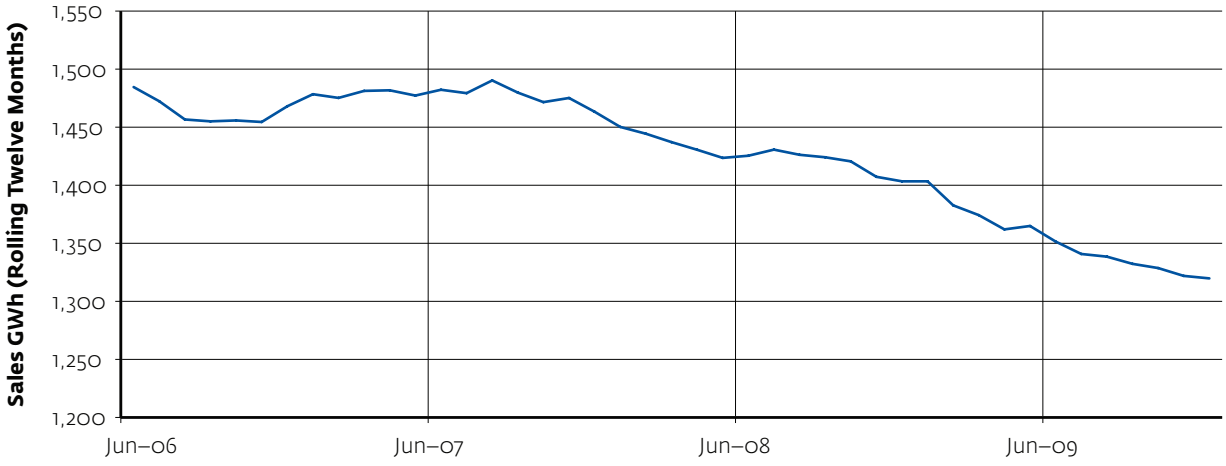
5.5.1 The South Australian economic outlook

The State's economic outlook will be significant in determining sales growth during the regulatory control period. ETSA Utilities has sought independent advice from a number of reputable industry sources on this aspect of the forecast, and is keenly aware of the divergence of opinion on the economic outlook by the various economic research organisations.

Under normal circumstances economic forecasters will project different outlooks, even for relatively short periods of twelve months, let alone for the six years that is required for forecasting ETSA Utilities' sales to determine prices. With the world having experienced the Global Financial Crisis (GFC) and the uncertainty around the sustainability and rate of recovery from this crisis, this normal divergence in economic forecasts is exacerbated. Accordingly, ETSA Utilities has sought independent advice from a number of reputable industry sources in order to derive an economic outlook that can be used to reasonably project sales over the 2010–15 regulatory control period.

ETSA Utilities has recorded muted sales during the first six months of 2009–10, which seemingly indicates a continued decline in the industrial segment, and a modest commercial recovery from the GFC. These trends are illustrated by Figure 5.1, which demonstrates the trend in the industrial sector, and by Figure 5.2, where the commercial sector recovery can be seen to be offset by industrial sector.

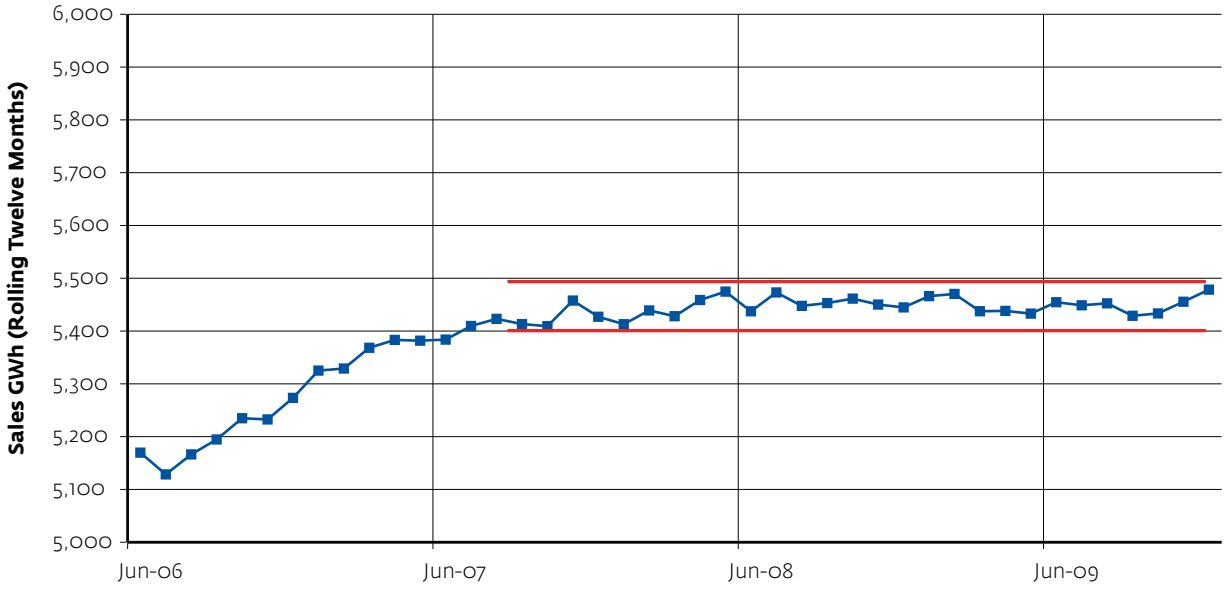
Figure 5.1: ETSA Utilities' Major Customer Sales



Recent events involving some of the more significant industries in South Australia provide supporting evidence of ongoing lower economic activity:

- in May 2009, General Motors cut back production at its Elizabeth plant from two shifts to single shift operation. This was followed, late in 2009, by a voluntary redundancy offer to a significant number of staff;
- the October 2009 announcement by Bridgestone of their shutdown of tyre manufacturing in South Australia, with a loss of approximately 600 workers at the Adelaide plant;
- the decline in the food and wine industries is continuing, with the most recent casualties of import competition and deteriorating export terms of trade being in November 2009, with the closure of Constellation Wines' Stonehaven Winery at Padthaway and the announcement of reduced production at the Riverland Berri fruit juice factory; and
- BHP's Olympic Dam mine expansion is not expected to proceed at the rate indicated in the EIS, which is still being assessed. As announced in 2009, the Olympic Dam project office has been significantly reduced and ETSA Utilities understands that at present staffing is limited to the level required to finalise the EIS approval process. ETSA Utilities notes that the AEMO, in its base case for the 2009 Statement of Opportunities has not incorporated the expansion of Olympic Dam. Accordingly, the progressive build-up in production is not expected to have any significant implications for the State's economic activity until beyond the 2010–15 regulatory control period.

Figure 5.2: ETSA Utilities' Business excluding Major Customer Sales



ETSA Utilities has obtained its advice on the economic outlook from a number of reputable industry sources, one of whom (KPMG Econtech) was used by the AEMO to provide the economic basis to undertake its forecast, while the other (Access Economics) was referred to by the AEMO as support for adopting the KPMG EconTech forecast. These two economic outlooks are in addition to that supplied by NIEIR. ETSA Utilities has chosen a scenario that represents a combination of their forecasts. These economic forecasts are submitted as Attachments E.5, E.6 and E.7 to this Revised Proposal.[54,55,56]

The high-level characteristics of the three economic scenarios that were obtained are summarised in Table 5.3.

The NIEIR model used to forecast ETSA Utilities' non-residential sales are segmented to the industry sector and sub sector level.[57] Accordingly, only the Access Economics and NIEIR forecasts would provide data with a suitable level of granularity to be used as forecast inputs. ETSA Utilities has therefore used a simple average of the sector and sub sector level components of these two economic forecasts as inputs to the sales forecasting model. The resultant weighted average of the sectoral GSP components is 1.9 percent, which is equivalent to KPMG Econtech's forecast of the average GSP. ETSA Utilities' derivation of this economic scenario is provided in Attachment E.8.

The sales forecasts that underpin this Revised Proposal have been prepared by NIEIR using these revised economic projections within the same forecasting model that was used for the Original Proposal. Sales forecasts are by customer sector and sub sector, based upon the economic drivers that underpin the sales for each sector.

5.5.2 Peak demand forecasts

Spatial peak demand forecast

The spatial peak demand forecast submitted as part of the Original Proposal was accepted by the AER as providing a realistic expectation of the demand forecast required to achieve the capital and operating expenditure objectives of the Rules.

The forecast in the Original Proposal is based on summer 2008-09 loads. At the time of submission of the Revised Proposal, summer 2009-10 is not yet over. The lead-time required to review the spatial demand forecast precludes its full review for resubmission with the Revised Proposal.

No significant recent network load developments or connections have emerged to influence the capital works program since the submission of the Original Proposal. The spatial peak demand forecast has therefore not been altered in this Revised Proposal.

For completeness, the process associated with developing the spatial peak demand forecast has been described in Attachment E.9 to this Revised Proposal.

Global peak demand

The global peak demand forecast submitted as part of the Original Proposal was also accepted by the AER as providing a realistic expectation of the demand forecast required to achieve the capital and operating expenditure objectives of the Rules.

As described in section 5.5.1 of this Revised Proposal, the economic assumptions underpinning both the sales and global demand forecasts have been updated. For this reason, the global peak demand forecast has also been refreshed. This forecast is described in Attachment E.10.[58]

Table 5.3: Economic forecast scenarios

Source	Access Economics	KPMG Econtech	NIEIR
Average GSP growth p.a. 2009-15	2.9%	1.9%	1.0%
Forecast granularity	By industry sector and sub-sector	Industry sector only	By industry sector and sub-sector

54 Attachment E.5: Access Economics, January 2010, forecast of economic variables for SA.

55 Attachment E.6: KPMG Econtech January 2010, forecast of economic variables for SA.

56 Attachment E.7: NIEIR January 2010, energy sales forecast.

57 The use of sub-sector levels is required in order to take into account the significantly differing electricity intensities between the sectors.

58 Attachment E.10: NIEIR January 2010, global peak demand forecast.

The global peak demand forecast also includes post-model adjustments for demand reductions, due to energy efficiency/greenhouse policies not reflected in the historical data. The impact of energy efficiency/greenhouse policy measures on demand is less significant than their intended effect on sales volumes, as set out in section 5.5.7. Attachment E.10 contains details of these post-model adjustments.

A revised reconciliation of the spatial demand and global demand forecasts is presented in section 5.5.10. The purpose of this reconciliation is to demonstrate the overall alignment between the demand growth rates of these different 'bottom-up' and 'top-down' forecasting approaches. This comparison also serves to illustrate that the energy sales forecast, which uses the same economic assumptions, is consistent with the spatial demand forecast, that is a driver of the capital and operating expenditure requirements.

5.5.3
ETSA Utilities' energy sales forecasting model

Desirable features of a sales forecasting model

Frontier Economics has set out in its report the usual approaches to forecasting energy sales and the desirable features of an energy sales forecasting model.[59] Table 5.4 summarises those requirements and records how the NIEIR forecasting model employed by ETSA Utilities matches the requirements.

Table 5.4 illustrates that the NIEIR forecasting process employed by ETSA Utilities has been designed to satisfy all of the desirable forecasting model requirements and incorporate features aligned with econometric best practice.

NIEIR has a long established reputation of providing economic advice and forecasts to all sectors of the electricity supply industry and regulators. A summary of NIEIR's relevant experience is included as Attachment E.11 to this Revised Proposal.[60]

5.5.4
'Business as usual' sales forecasts

The forecast analysis of sales is set out in this section for each customer segment. These forecasts represent 'business as usual', based on the environment and policy framework which applied in the period prior to the new regulatory control period, with the exception of the following new policy initiatives:

- the forecasting models for residential and commercial/industrial sales contain adjustments for 'own price' (electricity) and 'substitute price' (gas) drivers. The impact of the Federal Government's proposed introduction of the CPRS is included in the forecast price and thereby factored into the output of these models; and
- the impact of a range of Federal and South Australian Government policy decisions on incentives and regulations, which affect the rate of decline in electric resistance hot water sales have been factored into the forecast consumption estimates for that sector.

A range of other post-model adjustments are applied to the residential and commercial/industrial customer segments, to take into account other changes in government policy, particularly in relation to the effect of the suite of energy efficiency measures which have been proposed.

The sales modelling was carried out by NIEIR using the same models that were used for the Original Proposal. The model was updated with the economic parameters described in section 5.5.1, representing a combination of forecasts by different economic forecasters.

59 Attachment E.1: Frontier Economics, AEMO modelling, January 2010, pp.8–11.

60 Attachment E.11: NIEIR's relevant experience.

Table 5.4: Energy sales forecasting model

Element	Requirement	NIEIR modelling approach
Forecast approach	To suit available customer segment data, a combination of approaches is common: • Top-down (economic) • Bottom-up (appliance build up) • Trend analysis	A combined approach to forecasting is employed for each segment: • Commercial • Industrial • Residential • Hot water • Public lighting • Post-model adjustments • All customer segments
Dependent variable	Should capture as closely as possible the commodity on which the customer makes consumption decisions.	Dependent variable is sales in GWh.
Independent variables: Economic drivers	Typical drivers are: • Economic activity • Own price • Substitute price	Economic drivers are: • residential segment real income • commercial and industrial–GVA by industry sector and sub sector Forecast price segmented by customer class. Gas price by customer segment.
Other independent variables	To capture any other significant driver of consumption. Weather normalisation, summer and winter.	Residential customer numbers • Summer and winter weather normalisation for residential, business and commercial • Price (including CPRS)
Non stationarity of variables(1)	Variables should be tested for stationarity.	Variables have been tested for stationarity.(2)
Segmentation	• Used to capture and explain differences in customer segment response • All drivers linked as closely as possible to the customer segment being modelled	• Business forecast is at sector and sub sector level using ABARE energy data • Residential forecast has new/old segmentation • Hot water, public lighting segments separately considered
Model dynamics	Need to accommodate short and long run reactions to price change (price elasticity).	Long run price response is phased in over several years.
Post-model adjustments	Needed where relationships have not been captured in historical data.	Post-model adjustments for: • Small scale solar PV units • Energy Efficiency policy changes
Averaging of forecasts	Averaging of forecast outcomes improves accuracy.	Averaging of economic drivers by sector and subsector for non-residential segment.
Sensitivity analysis	Choice of independent variables should include any for which sensitivity analysis is required.	Facilitated by independent variables that are commonly used economic parameters.

Note:

(1) A non-stationary variable is one where its relationship to energy sales over the period of analysis is not constant.

(2) NIEIR's projections of energy consumption are derived from growth equations. This is a common approach to modelling non-stationary variables. By taking the first difference (percentage change) of the variable, a non-stationary series can be converted to a stationary one and standard modelling and hypothesis testing (t-distribution test) can be applied.

5.5.5 Common forecasting model characteristics

Two separate models were employed by NIEIR to model ETSA Utilities' sales for the residential and commercial/industrial customers. These models use different economic drivers, reflecting the different characteristics of those sectors. The two models, however, share a common approach to analysing the impact of the following major drivers of sales:

- weather and day type normalisation; and
- electricity price modelling (including the effect of the CPRS).

These two common aspects of the models are described below.

Weather and day type normalisation

Historical data on sales is analysed for the day type and for summer and winter day temperature, to enable the customers' response to these significant factors to be determined. The historical data is then normalised, to ensure that varying weather conditions and day type does not compromise the sales trends established from it.

Day type correction is made for weekends, public holidays and the Christmas close down period.

ETSA Utilities and NIEIR have refined the process used for the weather normalisation of historic data since the submission of the Original Proposal, and updated the model to include the most recent data. The changes made follow the preferred approach to weather normalisation set out by Frontier Economics.[61] NIEIR's model allows an overlap of normalisation for cooling degree days (CDD) for 7 months of the year and heating degree days (HDD) for 8 months of the year.[62] Such a model has been in use for several years, allowing weather compensation in the typical winter and summer months as well as for unusual conditions in the 'shoulder' months.

Not unexpectedly, the increasing penetration of air conditioning (which has been confirmed by customer analysis[63]) has resulted not only in increasing summer peak demand but also a progressive trend to greater weather response in both summer and winter energy.

The modelling of weather effects is extended to three principal customer segments (residential, hot water and commercial/industrial). Three customer segments have been reconciled back to the overall sales volume correction and have incorporated the individual sales volume corrections. The daily sales weather modelling showed significant summer responses by residential and business, and significant winter responses by residential. Hot water responses are of a second order. Large industrial customers have very little response to weather, and so have not been included.

Electricity price effect (including CPRS)

The Carbon Pollution Reduction Scheme

The Federal Government released a White Paper on the CPRS in December 2008, which outlined the design of an emissions trading scheme and confirmed its introduction by 2010–11. In May 2009, the Government announced a delay to the introduction of the CPRS to July 2011, and set a cap to the price of permits of $10 per tonne in 2011–12. The commencement of emissions trading has since been deferred to July 2012. The Government introduced the legislation to establish the CPRS to the Senate in November 2009. The Senate rejected this legislation the following month.

The United Nations Conference on Climate Change in Copenhagen in December 2009 failed to achieve a comprehensive international treaty with binding emissions targets. Notwithstanding this, the introduction of the CPRS is still the Federal Government's policy and no fundamental change to this policy or delay in its implementation has been announced.

ETSA Utilities has therefore retained the price effect arising from the introduction of the CPRS in the sales forecast of this Revised Proposal.

Modelling the price effect on sales

Significant electricity retail price increases are expected to take place during the 2010–15 regulatory control period, due to a combination of effects:

- energy cost increases;
- the introduction of the CPRS;
- transmission network price increases; and
- distribution network price increases.

The effect of price changes are modelled for each sector of the customer base using long term price elasticity of demand of -0.33 for residential customers and -0.31 for business and commercial customers. The use of a long-term price-elasticity applied gradually over several years is consistent with the approach used by MMA, which was commissioned by the AER to review the NSW DNSP's 2009 regulatory proposals.[64] In that decision, the AER also allowed the network price increase effect to be included in the price elasticity response that determined the overall sales forecast.

The customer demand response to price is well recognised as having short and long run components.[65] In the short run, the appliance and equipment stock remains unchanged and the demand response is a result of changed usage patterns. In the long run, the customer has a variety of other options including fuel substitution and the replacement of equipment and appliances with more energy efficient alternatives. Where durable goods are involved, the price elasticity of demand invariably increases with time.

61 Attachment E.1: Frontier Economics, AEMO modelling, January 2010, p.9.

62 CDD are determined for days above 18 degrees and HDD for days below 18 degrees.

63 McLennan Magasanik and Associates, The air conditioner market in South Australia—Report to ETSA Utilities, November 2008.

64 AER, New South Wales Distribution Determination 2009/10–2013/14, Final Decision, pp.103–104.

65 See, for example, the literature survey in: Dr Shu Fan and Prof Rob J Hyndman, Monash University, The price elasticity of electricity demand in South Australia and Victoria–Project 08/04—ESIPC and VenCorp, 22 October 2008, pp.8,9.

To approximate this build-up effect on sales of a price change, ETSA Utilities has assumed that the price effect takes place over a period of six years, whereas the AEMO assumed a uniform one-year lag.[66] Table 5.5 provides a comparison of the price elasticity assumptions used by ETSA Utilities and the AEMO. The total cumulative effect on sales, over the 2010–15 regulatory control period, is similar to the AEMO's assumption of a one year lagged step change despite the difference in the headline price elasticity adopted under each approach.

ETSA Utilities has made an initial sales forecast excluding the impact of the distribution network price. This initial sales forecast has then been used to determine the network price, which has then been used to determine the sales impact of the total customer retail price, ie a single-step solution has been employed to determine the distribution network price effect on consumption, rather than a more precise solution involving more than one iteration. Therefore, there is no circularity in ETSA Utilities' approach, whilst reasonably taking into account a forecast of the retail price expected to be experienced by customers.

In this Revised Proposal, the distribution network price is the only component of the retail price which has been altered from the prices assumed in the Original Proposal. This change reflects the updated revenue and sales forecast.

5.5.6 Electricity sales by customer segment

For the purpose of analysing sales, ETSA Utilities has segmented its customer base as follows:

- residential;
- commercial and industrial excluding Major (by sector and manufacturing sub sector);
- major business (by sector and manufacturing sub-sector);
- hot water; and
- public lighting.

The sales for each of these segments are considered under the following headings.

Residential sales

ETSA Utilities' forecast was developed with NIEIR's econometric models of residential sales. These models link residential sales growth to:

- real income per capita;
- real electricity prices;
- the price of gas; and
- weather conditions.

In addition, the residential customer base has been segmented into new and old customers, which display markedly different consumption characteristics, as described in section 5.5.3 of the Original Proposal.

The forecast sales to the residential segment resulting from the application of the above assumptions are set out in Table 5.9.

The residential sales are also subject to the post-model adjustments set out in section 5.5.7. The effect on residential sales for the in house use of solar photovoltaic generation is included in section 5.5.7.

Commercial and industrial sales

NIEIR's existing South Australian electricity forecasting model was used to drive the electrical energy projections for each scenario.

The NIEIR model is an industry-based model which uses:

- the ABARE energy demand data;
- projections of gross state product and output by industry; and
- other variables including real electricity prices, gas prices and weather conditions.

The GSP projections have been based on a combination forecast from NIEIR and Access Economics.

Table 5.5: Price elasticity assumptions

	Residential	Business	Total GWh
Price elasticity	-0.33 (-0.055 per year for 6 years)	-0.31 (-0.052 per year for 6 years)	
Cumulative sales effect GWh	-418	-805	-1223
Price elasticity	-0.236 one year lag	-0.188 one year lag	
Cumulative sales effect GWh	-526	-653	-1179

66 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts, p40–41.

The sales for these customers are segmented into a total of 9 commercial and 13 industrial ASIC (Australian Standard Industrial Classification) classes for the purpose of forecasting. Post-model adjustments have been applied for the lighting MEPS for Commercial. No other policy adjustments have been made to this segment.

The forecast sales to the commercial and Industrial segment resulting from the application of the above assumptions are set out in Table 5.9.

Major Business sales

A similar approach is used for this customer segment to that applied to Commercial and Industrial Sales (see above). A separate increment for Major Business sales has been included for the desalination plant. This is in addition to any economy-based sales calculations, with the estimated based on discussions with the customer involved.

The most recent forecast of sales to major businesses is set out in Table 5.9.

Hot water sales

The forecast consumption of this customer segment will be dramatically affected by energy efficiency policy measures during the 2010–15 regulatory control period, as follows:

- new resistance hot water installations have effectively been banned by current building standards, except in special circumstances;[67]
- the existing customer base is subject to attrition, as hot water appliances fail and are renewed at the end of their life by other more energy efficient forms of water heating.[68, 69] From July 2009, the replacement of electric resistance storage water heaters have effectively been banned except in special circumstances.

A key assumption deriving the decline in hot water sales is the life of the existing resistance electric appliances. ETSA Utilities has confirmed by research and discussion with the appliance manufacturers that a reasonable assumption for the life of a hot water system is in the range of 7–10 years.[70] The hardness of Adelaide water accelerates the deterioration of these appliances, so the lower end of this range is likely to be appropriate in the South Australian context. It should also be noted that from their research, MMA calculated an average life for electric hot water services of 9 years. ETSA Utilities has adopted a conservative life of 10 years in its modelling of this segment's consumption.

ETSA Utilities has carried out analysis of its customer records for current hot water sales and other research[71], which supports the following assumptions concerning the way in which the hot water sales will be affected by the progressive transition to other more energy efficient forms of electric water heating and alternative fuels.

Attachment E.12 provides the methodology and calculation used to derive the hot water sales.

Existing appliance stock

The proportion of existing dwellings with electric hot water heating varies, depending on where reticulated gas is available. The hot water fuel type for existing dwellings is illustrated in Table 5.6.

New dwellings

The proportion of new dwellings with electric hot water heating varies where reticulated gas is available. The heating technology and fuel type for new dwellings is illustrated in Table 5.7.

Hot water conversions

When electric resistance hot water appliances are replaced, most are not replaced with a similar appliance. Again it should be noted that where gas is available, the recent change to building standards bans the replacement of electric storage heaters. Where gas is not available, electric storage is only allowed in special circumstances. This is resulting in a transition to other more energy efficient appliances (eg, solar boosted electric and heat pump) and alternative fuels (gas). Table 5.8 illustrates the conversions for new dwellings.

It should be noted that the average annual consumption of an electric resistance hot water appliance is 2640 MWh, whereas the average consumption for both heat pump systems and solar boosted electric storage systems is approximately the same, at 750 kWh per annum. These amounts are consistent with those used by the AEMO in their review. These forms of replacement appliance thus have a significant effect on the overall sales to the hot water segment.

Forecast hot water sales

The forecast sales for the hot water segment based on the application of the above analysis are set out in Table 5.9.

The hot water sales set out in Table 5.9 do not incorporate early unit replacements, which are encouraged by REES. Accordingly, any possible cross over with the impact REES initiatives (set out in section 5.5.7) has been avoided.

67 Government of South Australia Department for Transport Energy and Infrastructure, December 2009, A Guide for People Building a New Home, Alteration or Addition.

68 Government of South Australia Department for Transport Energy and Infrastructure, December 2009, A Guide for Replacing or Installing Water Heaters in Established Homes.

69 Email communication (Confidential), 4 November 2009.

70 Energy Sustainability Victoria, April 2002, Choosing a hot water system.

71 New electric hot water customer numbers per year and inactive hot water customer numbers per year.

Public lighting sales

The estimate of public lighting sales has not been altered from the Original Proposal. This sales forecast was based on estimates of the projected population of luminaires and their average energy consumption.

Some of the requirements of the MEPS for residential and commercial lighting will influence public lighting sales. However, at this time no specific MEPS applies to public lighting. The potential replacement of older fittings with more energy-efficient luminaires has therefore not been factored into this forecast, resulting in an annual growth in forecast consumption of this sector over the next five years almost unchanged from the 2005-10 regulatory control period. It is likely that this simplifying assumption will overestimate the sales in this category.

Table 5.6: Existing stock of hot water appliances

Existing appliance stock	Electricity only 30%(1)	Gas available 70%(1)	Total
Electric	94%	18%	41%
Gas	0%	81%	56%
Other fuel	6%	1%	3%

Note:
(1) Percentage of total residences respectively with only electricity available and those with gas available.

Table 5.7: Hot water installations in new areas

New dwellings	Electricity only 15%(1)	Gas available 85%(1)	Total
Storage	5%	0%	0.8%
Solar boosted electric or heat pump	89%	6%	18.5%
Gas	0%	93%	79.1%
Other fuel	6%	1%	1.7%

Note:
(1) Percentage of total residences respectively with only electricity available and those with gas available.

Table 5.8: Electric storage hot water appliance conversions

New dwellings	Electricity only 15%(1)	Gas available 85%(1)	Total
Storage	5%	5%	5.0%
Solar boosted electric or heat pump	90%	77%	80.9%
Gas	0%	18%	12.6%
Other fuel	5%	0%	1.5%

Note:
(1) Percentage of total residences respectively with only electricity available and those with gas available.

Summary of sales before post model adjustments

The sales for each of the consumption sectors described above are set out in Table 5.9. These sales are before the application of post-model adjustments, but include the effects of the economic projections and the price-elasticity response to the forecast retail electricity price increases.

5.5.7 Post-model adjustments

As referred to in section 5.4.2 and described in Attachment E.3, the inclusion of post-model adjustments to the sales forecast, to represent anticipated changes in consumption due to influences that are not represented in historical data trends, is justified. These adjustments arise from energy efficiency policies, which will result in either a step or progressive change in the equipment and consumption patterns of customers. Frontier Economics confirms the need for such adjustments,[72] and MMA have reviewed the individual post model adjustments and found that there is a sound basis for incorporating such an adjustment in each case.

That energy efficiency policy changes will take place during the 2010–15 regulatory control period is beyond doubt. The CoAG intergovernmental agreement presages a coordinated approach by governments. This has the objective of accelerating the development of new energy efficiency initiatives for households and businesses to complement the introduction of the Carbon Pollution Reduction Scheme (CPRS).[73] Minister Garrett encapsulated this thrust when he said:[74]

> *'Collectively, these measures lay the foundation for a nationally consistent approach to energy efficiency, helping households, Businesses and the community to lower their energy use and save money. By becoming more efficient, we will help to reduce the energy intensity of the Australian economy overall, which is critical to our transition to a low pollution future'.*

There have been numerous recent developments in this area and ETSA Utilities has taken the opportunity to review all of the post-model adjustments that were applied to the sales forecast of the Original Proposal, including the effect of the May 2009 Federal Government budget energy efficiency initiatives.[75]

Table 5.9: Sales before post-model adjustments (GWh)

Year	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Residential	3,588	3,633	3,680	3,724	3,765	3,806
Commercial	3,144	3,205	3,249	3,247	3,301	3,353
Industrial	2,411	2,413	2,476	2,454	2,488	2,502
Hot Water	645	594	543	493	444	395
Street lighting	114	117	120	123	126	129
Major business	1,289	1,422	1,536	1,590	1,589	1,574
Sales excluding major business *Growth*	9,257	9,369 *1.2%*	9,525 *1.7%*	9,548 *0.2%*	9,679 *1.4%*	9,789 *1.1%*
Total sales *Growth*	11,192	11,384 *1.7%*	11,604 *1.9%*	11,632 *0.2%*	11,712 *0.7%*	11,758 *0.4%*

72 Attachment E.1: Frontier Economics, AEMO modelling, January 2010, p.8.

73 Council of Australian Governments, 2 July 2009, National Partnership Agreement on Energy Efficiency, pp.3–4.

74 Streamlining the Australian Government's Climate Change Programs and Making Energy Efficient Choices Easier, 12 May 2009, pp.1–2.

75 Department of the Environment, Water, Heritage and the Arts, 12 May 2009, Environment Budget Overview 2009-10—National Strategy on Energy Efficiency.

The impact of Equipment Energy Efficiency (E3) programs has been forecast to significantly increase during the 2010–15 regulatory control period.[76] Despite this, no adjustments have been incorporated for future policy measures which either has not been initiated or they have not been fully developed such as the green loans program and the improvement in energy use information to households via their energy bills that is currently the subject of a Consultation Regulatory Impact Statement. ETSA Utilities notes that in 'Equipment Energy Efficiency Program Achievements 2008–09'[77] that a wider range of products are expected to be covered by MEPS and Labelling initiatives than those incorporated in this forecast[78].

The post-model adjustments that have been incorporated into the sales forecast of the Revised Proposal are set out in this section, and are detailed in Attachment E.13.

In preparing this component of the sales forecast, ETSA Utilities has incorporated the considerations and findings of MMA[79].

This section reviews the influence of these adjustments on the sales forecast. The energy efficiency measures also deliver some complementary reduction in network demand. The effect of energy efficiency measures on the network demand is covered in section 5.5.2 and Attachment E.10.

It should be noted the effect of electricity price on consumption is factored into the modelling for the residential and commercial/industrial customer segments, and that as a consequence, the price effect of the introduction of the CPRS and network price increase is included at that stage. In addition, the modelling of sales for the hot water segment takes into account the effect of a range of policy initiatives.

For the purpose of analysing post-model adjustments to sales, ETSA Utilities has structured the review of these adjustments into the following categories:

General conservation effects
- network demand management impacts; and
- overlap of pricing and policy effects.

Government programs
- Residential Energy Efficiency Scheme (REES);
- green loans program;
- energy efficient homes package; and
- photovoltaic generation.

Appliance efficiency standards
- lighting MEPS;
- air conditioning MEPS;
- television labelling and MEPS;
- set-top box MEPS; and
- appliance standby power.

Each of these aspects is considered in this section under these headings.

General conservation effects

Network demand management impacts

Network demand management initiatives, which have been considered by ETSA Utilities, have been principally directed at relieving peak demand rather than facilitating energy efficiency, although there can be some overlap. Whilst ETSA Utilities has undertaken significant investigations in the current regulatory period of various demand management initiatives, most of the trials have not yet progressed to the stage where the results can be fully evaluated, and only a small number of non-network solutions have been incorporated into ETSA Utilities' forecasts to deal with capacity constraints. The peak demand impact of these projects was incorporated into the specific spatial demand forecasts of the Original Proposal, which have not been updated in this Revised Proposal. The impact of these projects was not sufficiently material to be incorporated into the global demand or sales forecasts.

Should further demand management projects be identified within the next period as economically viable options to address capacity constraints, such projects may potentially have a material impact on overall sales. For this reason, ETSA Utilities has again advocated a modification to the AER's proposed Demand Management Incentive Scheme Part B, as discussed in chapter 9 of this Revised Proposal.

Should the State Government endorse further trials or roll-out of ETSA Utilities' Peakbreaker+ device, this may have a material impact on both peak demand growth and sales. If this takes place, it is anticipated that the project funding would be treated as a pass through and would include allowances for sales, capital and operating expenditure effects.

This Revised Proposal confirms that the impact of planned network demand management on sales will be negligible during the 2010–15 regulatory control period.

76 George Wilkenfeld and Associates Pty Ltd, January 2009, Prevention is Cheaper than Cure—Avoiding Carbon Emissions through Energy Efficiency—Projected Impacts of the Equipment Energy Efficiency Program to 2020, p.28.

77 Equipment Energy Efficiency Program Achievements 2008–09, p.40.

78 Equipment Energy Efficiency Program Achievements 2008–09, December 2009, p.40.

79 McLennan Magasanik Associates, November 2008, Report to ETSA Utilities—The air conditioner market in South Australia.

Overlap of price and policy effects

In the review of ETSA Utilities' sales forecast, the AEMO raised the issue that there was a degree of overlap between the consumer response to rising prices and policies which encourage customers to become more energy efficient. The AEMO stated:

> *'Double counting might occur, for example, when the baseline forecasts include a consumer response to rising prices, while separate post model adjustments are also included to reflect programs aimed at assisting consumers discover and implement changes to economise on electricity use in a rising price environment. AEMO's thinking is that price effects are not exclusively about 'switching appliances off', but come about in part because some policies facilitate the process of consumers becoming more efficient in their use of electricity. Forecasts should include either the price effect or the policy effect–not both, because, to some extent at least, they are not additive effects but different perspectives on the same phenomenon.'*[80]

The potential impact of this effect was estimated by MMA in their review of post-model adjustments to the sales forecast. MMA concluded:

> *'On average, E3 measures scheduled for introduction during the forecast period are expected to reduce energy consumption by approximately 15% by 2020. Assuming that half of this reduction occurs in the period to 2015, price effects over this period should be reduced by 7.5% to account for the overlap with E3 programs.'*[81]

ETSA Utilities has adopted the adjustment proposed by MMA and incorporated it into the sales forecast of the Revised Proposal. This effect is set out in Table 5.10.

Government programs

Residential Energy Efficiency Scheme

The Residential Energy Efficiency (REES) Scheme has arisen from the South Australian Government's Strategic Plan to achieve a 10 percent reduction in the energy consumption of dwellings by 2014[82].

REES imposes liabilities on South Australian electricity and gas retailers to reduce the greenhouse gas emissions attributable to their residential customers. The majority of the greenhouse gas reductions will be achieved from reduced electricity consumption.

The scheme is generally applied, but 35 percent of customers must be in priority groups, essentially low income households. The level of incentive is based on the deemed GHG abatement (in tCO_2e) for the life cycle of a particular accredited activity such as the retirement of inefficient refrigerators and freezers. Retailers meet their REES liabilities by using their certificates of deemed tCO_2e for approved installations. As the REES abatement target is increased, there will be a higher implied CO_2e price and the required means of abatement will move towards higher cost activities. Progressively increasing targets have been announced for calendar years 2009, 2010 and 2011, although the REES is planned to continue through the 2010–15 Reset Period.

It should be noted that the REES incentives have been designed to be independent from other initiatives such as MEPS and the new Residential Building Standards, and therefore in most instances the resulting sales reductions will be additional.[83]

Whilst REES does apply to the conversion of electric resistance hot water systems to less carbon intensive appliances, initial experience has been that the premature replacement of hot water systems is not attractive and it has therefore not made a material impact on the sales to this customer segment, set out in section 5.5.4

The impact of REES on energy sales will arise from a diverse range of retailer initiatives and energy audit findings. Of these, the only area where some potential overlap with other initiatives has been identified is with the installation of ceiling insulation under the recently announced federal energy efficient homes package. As recommended by MMA, the potential double-counting of sales reductions under these schemes has been resolved by reducing the quantum of the post model adjustment for the effects of REES during the life of the Federal Government's home insulation scheme.

The forecast impact of REES is set out in Table 5.10.

Green loans program

The Federal Government commenced a green loans program on 1 July 2009 to provide audits, advice and low interest loans of up to $10,000 for retrofits aimed at abating greenhouse gas emissions and water efficiency. The green loans program is expected to complement REES, by providing loans for that portion of retrofit and related costs not covered by REES incentives.[84]

The green loans program will clearly have an impact on energy savings, mainly through the reduced heating and cooling requirements in homes equipped with insulation. However, the specific impact of this program has not been separately accounted for, nor have additional sales reductions been incorporated into the forecasts for REES and the energy efficient homes package.

80 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts, p.29.

81 Attachment E.2: McLennan Magasanik and Associates, December 2009, Review of post-model adjustment methodology, p.15.

82 South Australia's Strategic Plan, 24 January 2007, Objective 13.14.

83 Maunsel/AECOM page 54—Government Department (DTEI) advice that REES savings in lighting and hot water are designed to be additional to MEPS lighting and hot water policy.

84 Department of the Environment, Water, Heritage and the Arts, December 2009, Green Loans—Program Guidelines.

Energy efficient homes package
As part of the economic stimulus package, this Federal Government program provides rebates for the installation of ceiling insulation in uninsulated homes and for the installation of solar hot water appliances. The rebate is currently $1,200 for insulation and $1,600 for solar hot water.[85, 86] The program will operate through to 2012 and the funding for rebates has been capped at $2.4 billion.

The impact of this package on energy sales has been factored into estimates of the impact of thermal insulation of homes below. The effect of the solar hot water rebate has been included in the analysis of hot water sales in section 5.5.4.

Summary impact of thermal insulation of homes
The government programs which will contribute to an increase in the proportion of homes which have thermal insulation are:
- REES;
- the green loans package; and
- the energy efficient homes package.

As a starting point to assess the potential for thermal insulation to impact on ETSA Utilities' energy sales, the proportion of uninsulated homes in South Australia was determined by the Australian Bureau of Statistics to be the second highest in Australia (being marginally exceeded only by the ACT).[87] Approximately 17.5 percent of customers do not have ceiling insulation.

The impact of adding insulation to those dwellings on residential heating and cooling requirements, and hence electricity sales, is analysed in Attachment E.13. Table 5.10 summarises those outcomes.

Solar photovoltaic generation
In this Revised Proposal, ETSA Utilities has revised the expected effect on electricity sales of energy generated by solar photovoltaic (PV) installations.

There are a number of incentives to install solar PV installations that have proved very popular with ETSA Utilities' residential customers, as follows:
- the South Australian solar feed in tariff of 44 ¢/kWh for net energy input to the grid;
- federal rebates for PV installations; and
- the value of the Renewable Energy Certificates (RECs), which accompany the generator installation.

As at June 2010, there are now expected to be over 15,500 solar PV installations connected to ETSA Utilities' network. However, it is anticipated there will be some moderation of this initial spate of solar PV take-up during the 2010–15 regulatory control period, because:
- in July 2009, the federal rebate was reduced, from $8.00/watt capped at $8,000, to $5.00/watt capped at $7,500, although the income eligibility limit placed on the purchaser was removed; and
- the value of Renewable Energy Certificates (RECs) under the Renewable Energy Target (RET) scheme has recently declined, as a result of an increasing number being issued for newly eligible technologies such as solar hot water installations. The number of RECs available for PV installations is reducing over the Reset period, so reducing the supply of RECs. ETSA Utilities has conservatively assumed that the value of the RECs would remain unchanged at $35, whereas the AEMO assumed an increase in their value from $40 to $60 over the period to 2030.[88]

ETSA Utilities has surveyed the existing installations on its network and confirmed their average size to be 1.4 kW, which equates to an expected annual energy generation of 2.24 MWh. These statistics have formed the basis for calculations of the energy generated, as detailed in Attachment E.13. By 2015, it is anticipated that approximately 4 percent of ETSA Utilities' residential customers will have installed a solar PV generator.

Table 5.10 summarises ETSA Utilities' forecast of solar photovoltaic energy generation for the 2010–15 regulatory control period. This is split into the energy used in-house (60 percent) and energy exported to the grid (40 percent).

The cost associated with the payment of feed in tariff amounts to ETSA Utilities' customers with solar installations, for energy exported to the grid, has been included in the operating cost forecast of this Revised Proposal.

85 Department of the Environment, Water, Heritage and the Arts, 1 December 2009, Energy Efficient Homes Package—Home Insulation program—Guidelines Version 5.

86 Department of the Environment, Water, Heritage and the Arts, 2 November 2009, Energy Efficient Homes Package—Solar Hot Water Rebate—Guidelines and application form.

87 Australian Bureau of Statistics, March 2008, 4602.0.55.001—Environmental Issues: Energy Use and Conservation.

88 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts, p.27.

Appliance efficiency standards

Modelling appliance energy savings

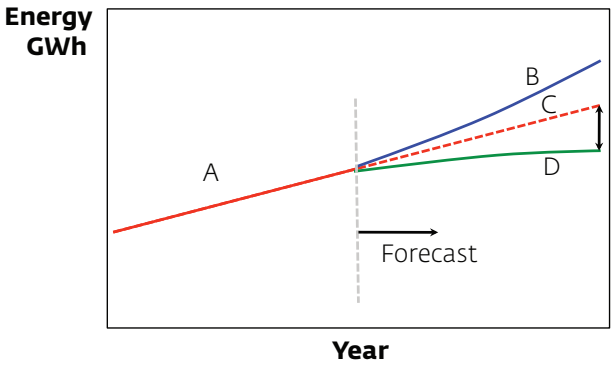
Many of the appliance energy savings discussed in the following sections result from the application of MEPS, which are intended to introduce either a step or progressive reduction in energy consumption. ETSA Utilities has adopted the general approach in modelling the associated savings set out in Figure 5.3. This approach has been based on the estimates of historic and projected energy consumption set out in the Regulatory Impact Statements (RIS) associated with each MEPS.

With reference to Figure 5.3, the process for determining the estimated energy savings is as follows:

- the historic appliance consumption is represented as line A;
- the 'business as usual' forecast, with increasing appliance penetration and consumption, is the line B. This is derived from the RIS;
- the straight line projection of the historic consumption is line C. It is assumed that this is component of consumption has been built into ETSA Utilities' forecasts;
- line D is the revised forecast consumption, derived from the RIS's effect of expected energy efficiency improvements from its implementation onto the business as usual forecast (line B) which includes increasing appliance penetration; and
- the energy saving included in ETSA Utilities' forecast as a post-model adjustment is the difference between lines C and D. It only incorporates the energy efficiency reductions that are below the historic trend (line C).

This approach has been developed as a means of forecasting the impact of the MEPS using independently derived consumption data, without overstating the effect on ETSA Utilities' sales forecast. It directly addresses the concern that the AEMO had in its review of the Original Proposal[89] that post-model adjustments are inappropriate unless similar adjustments are also made to reflect the increasing penetration and use.

Figure 5.3: Modelling appliance energy savings



89 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts, p 34.

Lighting MEPS

A MEPS covering lighting will be introduced early in 2010. This will remove most incandescent light globes and some low voltage halogen (LVH) downlights and reflector bulbs from sale. This standard has already had some effect, as more efficient lamps (compact fluorescent lamps, or CFLs and some LVH) already have a substantial market share.

The associated RIS uses 2005 consumption data to estimate the energy savings that would result from implementation of the MEPS.[90] This MEPS will have an effect on both the residential and commercial sectors. It should be noted that the AEMO analysis of the energy savings attributable to lighting was based on the RIS consultation data and was to be updated when the RIS was finalised.[91]

ETSA Utilities' estimate of the sales impact of the lighting MEPS is illustrated in Figure 5.4, for sum of the residential and commercial sectors. The general approach described in the previous section was followed.

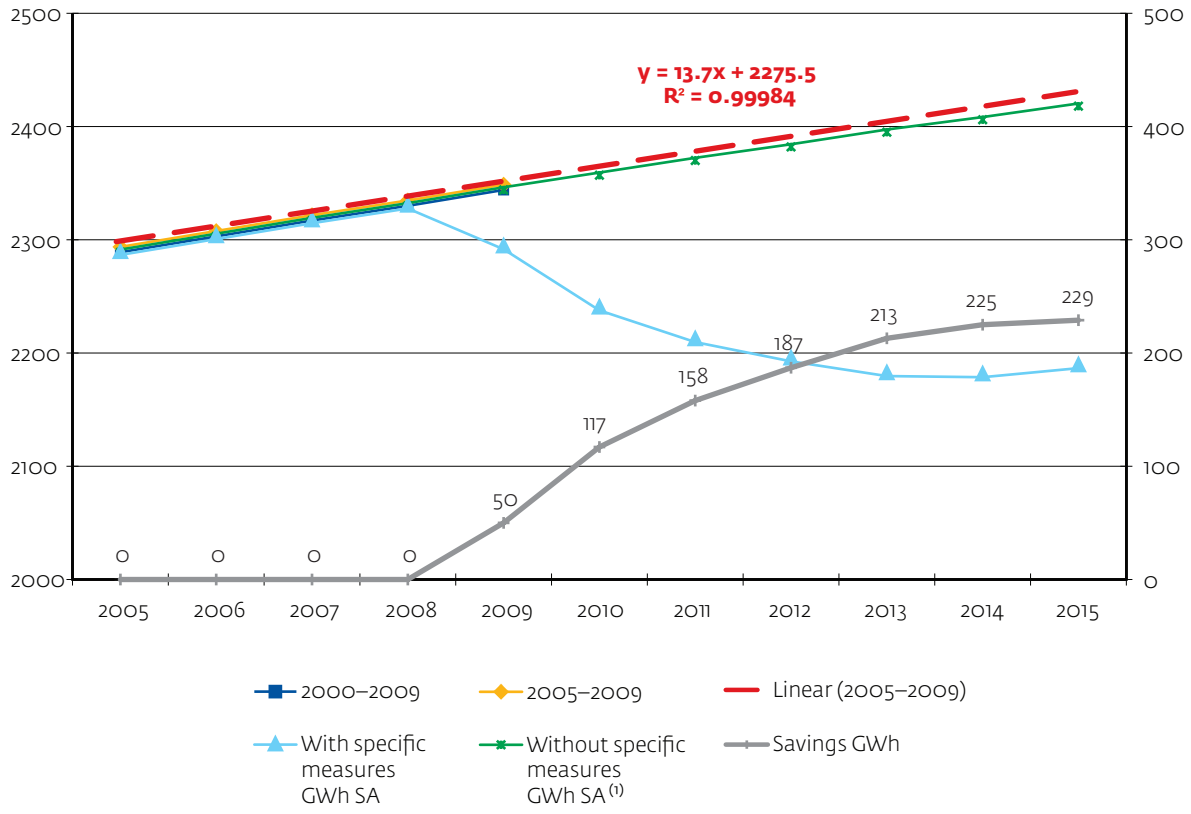
In Figure 5.4, the historical estimate of lighting sales is extrapolated to 2015 (the red dashed line). This is the base level from which the energy efficiency gains will be calculated. The green line below this represents the energy consumption without the MEPS. The additional savings impact of the specific measures imposed by the MEPS is shown as the blue line.

The lighting MEPs impact on the individual residential and commercial segments are set out in Attachment E.13. The allocation to residential and commercial segments is based on information provided in the lighting RIS.

The energy savings attributable to the MEPS is the difference between the latter two trajectories and this cumulative saving is shown as the grey line.

This consumption saving is shown in Table 5.10.

Figure 5.4: Impact of lighting MEPS on ETSA Utilities ' residential and commercial sales



Note:
(1) ie: business as usual.

90 Equipment Energy Efficiency Committee, September 2008, Regulatory Impact Statement Consultation Draft—Proposal to Phase-Out Inefficient Incandescent Light Bulbs—Prepared by Syneca Consulting, Report 2008/08.

91 AEMO, 1 October 2009, Review of ETSA Utilities sales and demand forecasts, p.33.

Air conditioning MEPS

MEPS have been in place for air conditioners for some years. Smaller three phase units were covered in 2001 and single phase units in 2004. The MEPS specifies the Energy Efficiency Rating (EER) of the units concerned.

A revised MEPS with coverage extended to all types of air conditioners to a rating of 65 kW will take effect in April 2010 and in 2011 will be modified to apply to the annual EER. The impact of these MEPS changes was estimated in the associated RIS.[92] The RIS has been used to forecast the energy savings that would apply to ETSA Utilities' population of air conditioners. A conservative estimate has been made of the influence of the MEPS being introduced in 2010 and 2011 compared with the trend in air conditioning load which incorporates the impact of the MEPS introduced up to then.

The RIS has been used to forecast the energy savings that would apply to ETSA Utilities' population of air conditioners. The derivation of the efficiency savings is explained in more detail in Attachment E.13. The post-model forecast adjustment to be applied is shown in Table 5.10.

Television labelling and MEPS

Mandatory labelling and MEPS for televisions are expected to be phased in during the course of the 2010–15 regulatory control period. These measures are set out in the associated RIS, together with the estimates of the expected energy efficiency gains.[93] The energy savings in the RIS are based on information from the first half of 2008 and are significantly higher than those of the Original Proposal, which were estimated for ETSA Utilities by Maunsell.

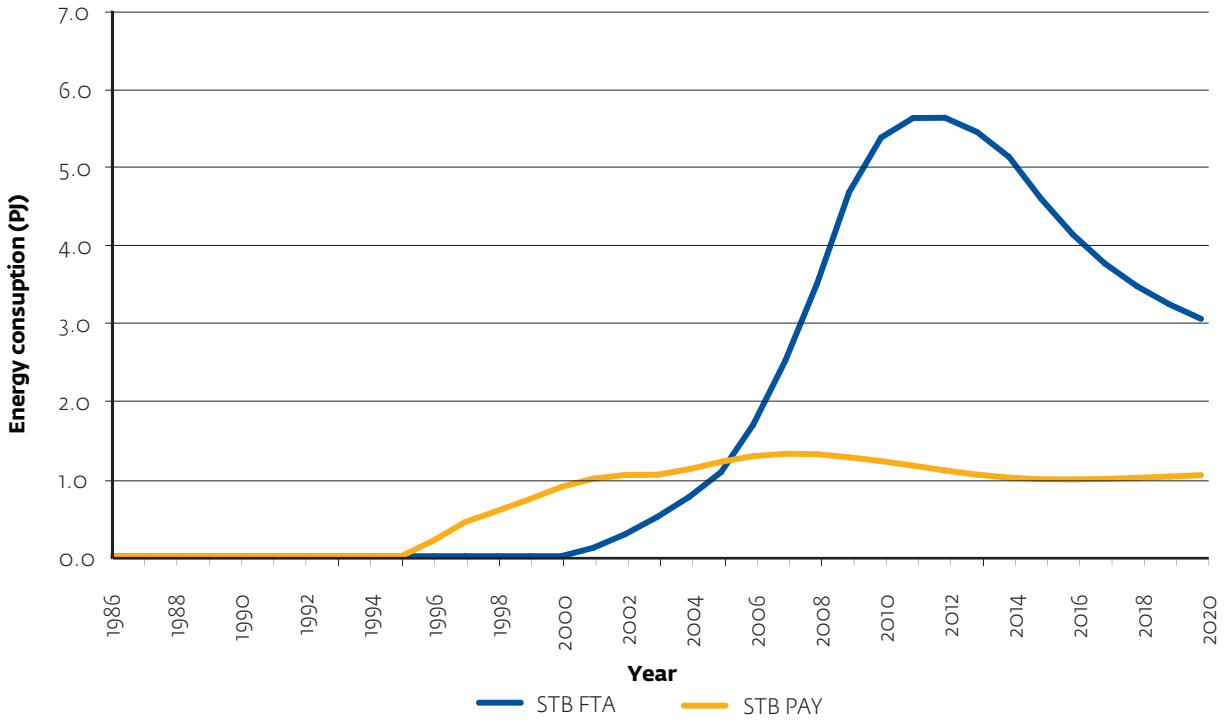
ETSA Utilities' forecast of the energy savings attributable to the energy efficiency measures for televisions have been included with the effect of set-top boxes (see separate section below) because of the interdependency created by the market penetration of digital televisions with inbuilt tuners.

Set-top boxes

A revised estimate of the post-model forecast adjustment for set-top boxes in ETSA Utilities' Original Proposal is provided in this section.

Set-top boxes became subject to a new MEPS in December 2008. The energy savings (Australia wide) arising from the adoption of the set-top box MEPS were estimated in the associated RIS for two scenarios, a base case and a low case where the penetration of digital televisions with integrated tuners increased.[94] See Figure 5.5 for projected set-top box consumption.

Figure 5.5: Energy Consumption (PJ)—Set-top Boxes in Australia from 1986 to 2020 (from DEWHA Figure 49)



92 Equipment Energy Efficiency Committee, September 2008, Regulatory Impact Statement—Consultation Draft—Revision to the Energy Labelling Algorithms and Revised MEPS levels and Other Requirements for Air Conditioners.

93 Equipment Energy Efficiency Committee, February 2009, Consultation Regulatory Impact Statement: Proposed Minimum Energy Performance Standards and Labelling for Televisions, Report 2009/03.

94 Equipment Energy Efficiency Committee, October 2007, Consultation Regulatory Impact Statement: Minimum Energy Performance Standards and Alternative Strategies for Set-Top Boxes, Report 2007/11.

Based on the low scenario in the RIS, scaled for the South Australian situation, the forecast energy savings attributable to the set-top box MEPS are included in the combined television and set-top box analysis (see section below).

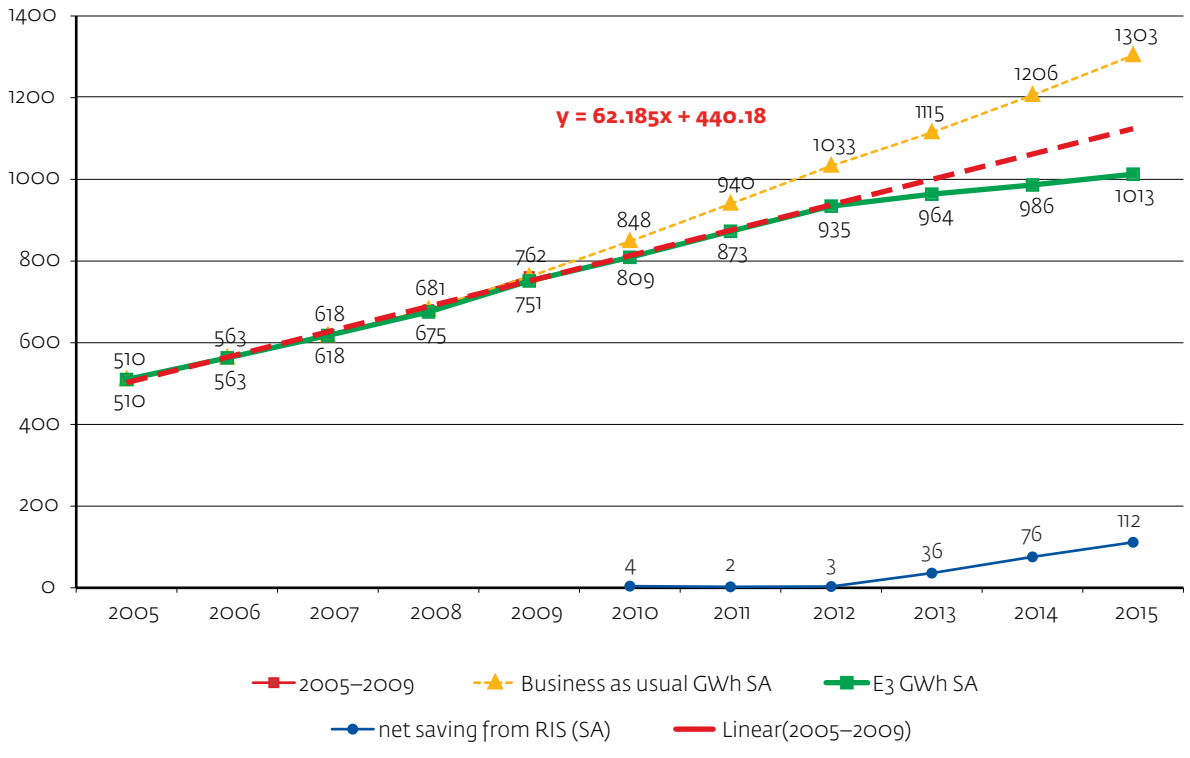
Televisions and set-top boxes

The process that ETSA Utilities has used to estimate the sales impact of the interrelated television and set-top box MEPS is illustrated in Figure 5.6. The historic energy usage by televisions[95] and set-top boxes[96] for SA was obtained from the RIS' for each of these items. The RIS also provided future energy projections with increasing appliance penetration (business as usual) and with E3 savings initiatives.

The approach adopted is described earlier in 'Modelling appliance energy savings'. To estimate the energy efficiency savings attributable to these measures that are below the historic sales trend, a straight line extrapolation of the energy consumption attributable to televisions and set-top boxes for the period of 2005-09 was used to calculate the base (dashed red line). The business-as-usual projection from the RIS was built up from increasing appliance numbers at existing levels of efficiency (dotted yellow line). The progressive impact of the energy efficiency measures in the RIS on the business-as-usual appliance population delivered an adjusted energy total (green).

The difference between the red dashed line and green line represents the energy savings attributable to this MEPS after adjusting for the increased appliance penetration that is forecast to occur. The net saving from the historic trend line has been included in the post-model adjustments attributable to the television labelling and MEPS and set-top box MEPS and are set out in Table 5.10. The derivation of the effciency savings is explained in more detail in Attachment E.13.

Figure 5.6: Impact of TV and set-top box MEPS on ETSA Utilities ' residential sales



95 Consultation RIS: Proposed MEPS and Labelling for Televisions, February 2009, table 36.

96 Consultation RIS: MEPS and Alternative Strategies for STB, October 2007, table 36.

Appliance standby power

In late 2002, the MCE published a Standby Power Strategy.[97] This strategy sets a one-watt target for the domestic appliance standby power requirement, by 2012. The strategy identified the appliances to be targeted and set out a comprehensive range of measures, including a staged enforcement process, by which the target is to be achieved. Since that time, a range of labelling and MEPS requirements has been introduced for specific appliances.

More recently, standby power has been estimated to account for approximately 10 percent of residential energy consumption.[98] As illustrated by Figure 5.7, this component of consumption has been and is expected to continue increasing steadily, since efficiency gains have been offset by an increased number of appliances drawing standby power.[99]

MMA's review of this post-modelling adjustment supported its inclusion, and noted the general consistency of other estimates with that developed by ETSA Utilities in the Original Proposal. MMA agreed with the AEMO that the 1 watt standby might not be fully implemented by 2020. MMA recommended progressive adjustments to the estimates to allow for this factor.[100]

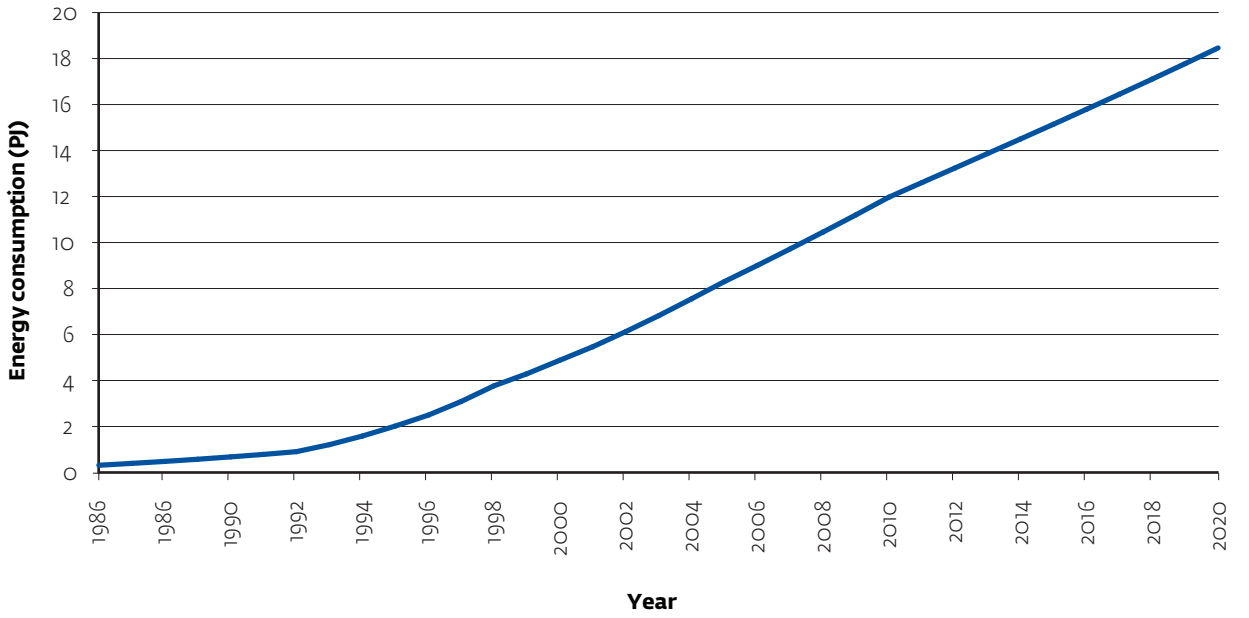
The standby power savings shown in Table 5.10 have been re-estimated from those of the Original Proposal for 11 common appliance types to incorporate the MMA adjustment. They exclude the efficiency gains that are forecast through the MEPS for individual appliances, specifically televisions and set-top boxes and air conditioners. The derivation of the efficiency savings is explained in more detail in Attachment E.13.

5.5.8 Summary of post-model adjustments

A summary of adjustments to the sales forecast to account for the effects of energy efficiency initiatives is included in Table 5.10.

The size of the post-model adjustments is significant, reflecting the opportunities for savings in this area and the commitment to green-house gas reductions through specific government policy initiatives. As shown in Figure 5.8, George Wilkenfeld and Associates (GWA) illustrated the relative size of these initiatives on residential end-use.[101]

Figure 5.7: Energy Consumption (PJ)—Other Standby in Australia from 1986 to 2020 (from DEWHA, Figure 54)



97 Ministerial Council on Energy, November 2002, Standby Power Strategy 2002–2012—'Money isn't all you're saving'.

98 Equipment Energy Efficiency Committee, October 2006, Report No 2006/10 Standby Power—Current Status.

99 Department of the Environment, Water, Heritage and the Arts, 2008, Fig.54, p.66.

100 Attachment E.2: McLennan Magasanik and Associates, December 2009, Review of post-model adjustment methodology ,table 19, p.71.

101 George Wilkenfeld and Associates Pty Ltd, January 2009, Prevention is cheaper than Cure—Avoiding Carbon Emissions through Energy Efficiency—Projected Impacts of the Equipment Energy Efficiency Program to 2020, p.18.

Figure 5.8: Historical and projected impacts of E3 Programs on residential sector electricity use, Australia.

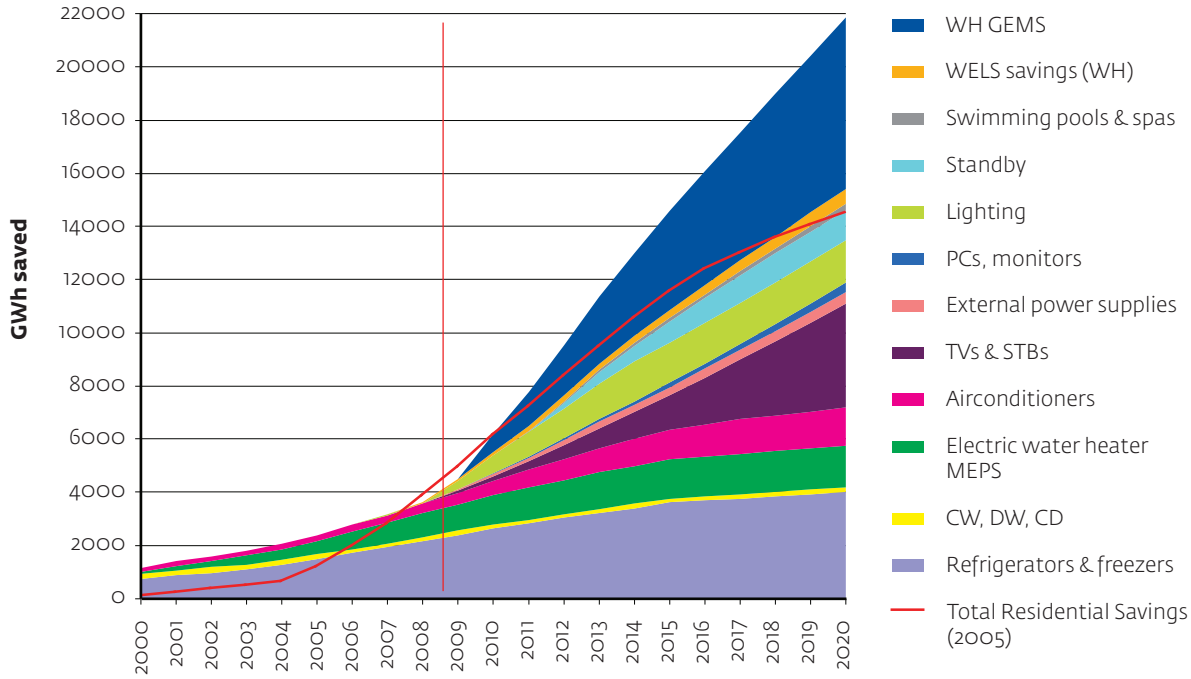


Table 5.10: Summary of post-model forecast adjustments for energy efficiency effects (GWh)

Year	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Government programs						
Price and policy overlap	0.0	-0.1	-0.7	-1.8	-3.0	-4.5
REES	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	0.0
Small scale solar PV units	9.9	8.1	6.7	6.0	4.7	3.4
Major business	1,289	1,422	1,536	1,590	1,589	1,574
Appliance efficiency standards						
Residential lighting MEPS	37.1	22.7	16.0	14.4	6.6	2.2
Commercial lighting MEPS	29.9	18.3	13.0	11.6	5.4	1.8
Air conditioner MEPS	0.0	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 annual sales reduction	**116.7**	**93.6**	**81.7**	**108.0**	**96.3**	**80.6**
Cumulative sales reduction	**116.7**	**210.2**	**292.0**	**399.9**	**496.2**	**576.8**

The ongoing impact of refrigerator and freezer MEPS on savings is apparent, as is the improvement in electric water heaters (since overtaken by additional policies, and included separately within hot water). The size of the escalation of these initiatives post 2009 dwarfs the pre 2009 initiatives. The relative impact on Australian sales can be seen. South Australia can expect to see 7.5 percent of these savings:

- Air conditioning: The step change in air-conditioning efficiency over and above the prior MEPS improvements;
- TV's and set-top boxes: Note that ETSA Utilities has not incorporated all of this item, only the amount over and above the historic trend for total energy use;
- Lighting: This is the residential component. There is also a commercial lighting component of a similar size;
- Standby: The savings are only projected to occur post 2009; and
- Water Heating Greenhouse Efficiency Measures: The replacement of electric storage with energy-efficiency alternatives such as gas, heat pump and solar boosted storage has been separately identified within hot water. The immediacy of impact of the new policy change in 2009 is apparent.

5.5.9 Tariff volume forecast

The revised sales forecast is submitted as Attachment E.7 to this Proposal. The tariff volume forecast is summarised in Table 5.11.

The forecast and its sectoral components, excluding major business, are illustrated in Figure 5.9. In this chart, the street lighting sales were included with Commercial.

Figure 5.10 illustrates the differential in growth rates of the individual customer sectors.

The disparity between the growth in customer sectors during the 2010–15 regulatory control period is evident from Figure 5.10. The major business sector includes new loads in the desalination plant and the Harden Army establishment at Edinburgh, which to a considerable extent, offsets flagging growth in other business sectors.

Table 5.11: ETSA Utilities revised sales volume (GWh)

Year	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Residential	3,588	3,633	3,680	3,724	3,765	3,806
Energy Efficiency (+ PV)	-87	-162	-231	-327	-418	-497
Net Residential	3,501	3,471	3,449	3,397	3,347	3,309
Growth		*-0.9%*	*-0.6%*	*-1.5%*	*-1.5%*	*-1.1%*
Commercial	3,144	3,205	3,249	3,247	3,301	3,353
Energy Efficiency	-30	-48	-61	-73	-78	-80
Net Commercial	3,114	3,157	3,188	3,175	3,222	3,273
Growth		*1.4%*	*1.0%*	*-0.4%*	*1.5%*	*1.6%*
Industrial	2,411	2,413	2,476	2,454	2,488	2,502
Growth		*0.1%*	*2.6%*	*-0.9%*	*1.4%*	*0.6%*
Hot Water	645	594	543	493	444	395
Growth		*-7.9%*	*-8.5%*	*-9.2%*	*-10.0%*	*-11.0%*
Street lighting	114	117	120	123	126	129
Major business	1,289	1,422	1,536	1,590	1,589	1,574
Sales excluding major business	9,141	9,158	9,233	9,148	9,183	9,213
Growth		*0.2%*	*0.8%*	*-0.9%*	*0.4%*	*0.3%*
Total sales	11,075	11,174	11,312	11,232	11,216	11,182
Growth		*0.9%*	*1.2%*	*-0.7%*	*-0.1%*	*-0.3%*

Figure 5.9: ETSA Utilities' energy sales forecast by sector

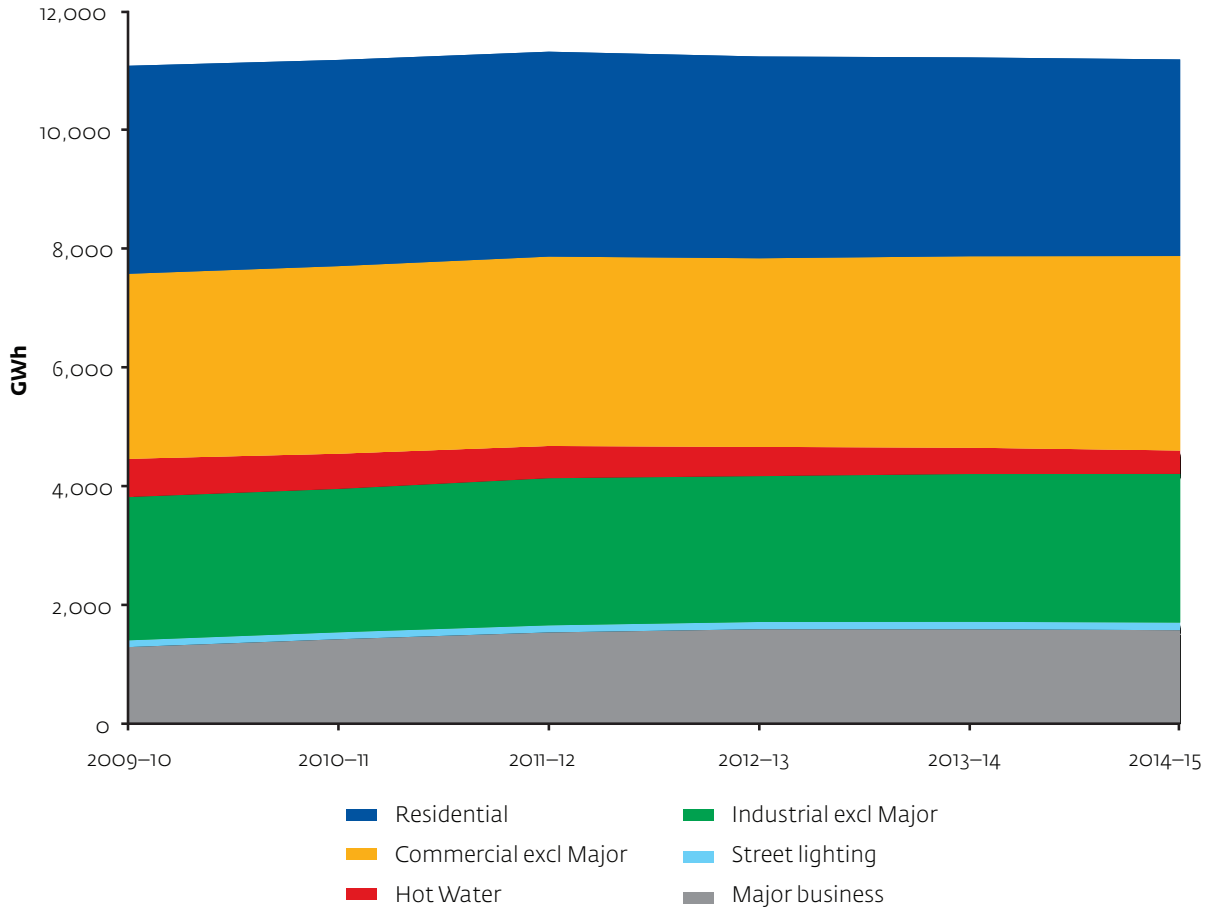
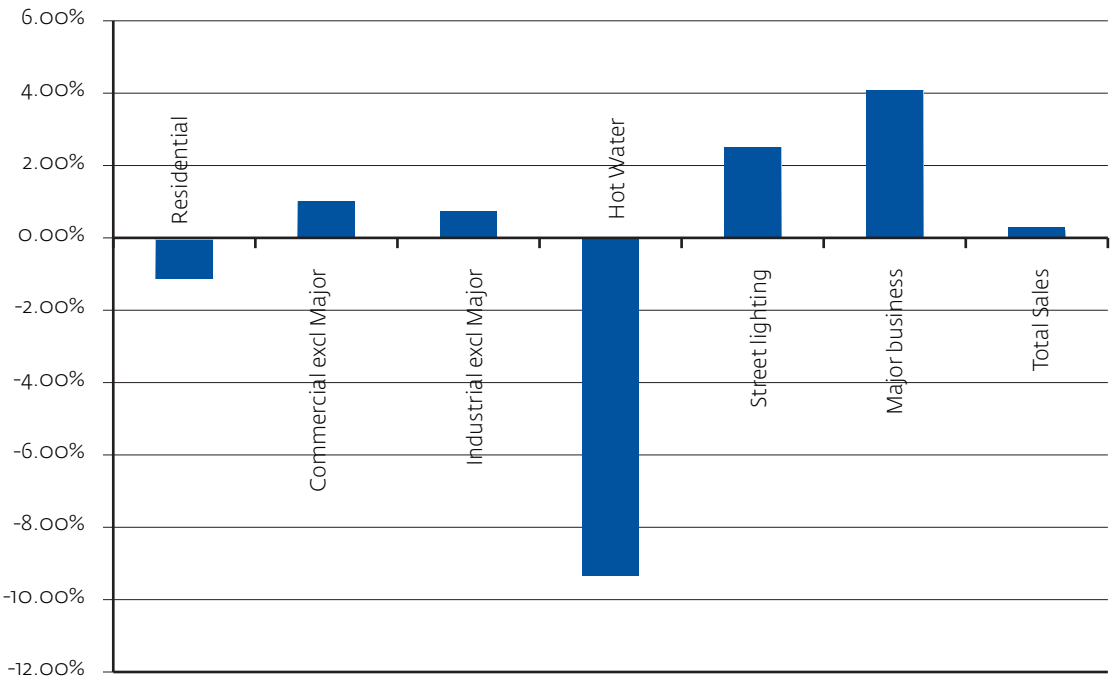


Figure 5.10: ETSA Utilities' energy sales forecast by sector



5.5.10 Reconciliation of demand forecasts

The global demand forecast described in section 5.5.2 provides a consistency check of the spatial forecasts used for planning the capacity of the network. By validating the correspondence between the spatial demand forecast and the economic projections underpinning the global peak demand forecast, it can assist in confirming the reasonableness of the sales forecast, which uses the same economic assumptions as the global demand forecast.

The correspondence between the demand forecasts is imperfect. There could never be an exact match between the two forecasts because of the effects of diversity, power factor and the influence of embedded generation, which is generally excluded from the spatial demand forecast.

These limitations mean that in practical terms, this comparison is limited to ensuring that the annual growth rates of the two demand forecasts are broadly consistent. A comparison of the two forecasts is included in Table 5.12.

The table illustrates a reasonable correspondence between the forecast growth rate of the top-down global demand, based on the expectation of a range of economic parameters, and the bottom-up spatial demand forecast, which is the diversified sum of individually assessed demand at each zone substation.

This comparison provides assurance that the economic assumptions, upon which the sales forecast is largely based, reasonably reflect a realistic expectation of demand growth to achieve the capital and operating expenditure objectives of the Rules.

The demand impact of the Policy Post-Model Adjustments is set out in Table 5.13

Table 5.12: Comparison between global and spatial demand forecasts (excluding major business)

Period	Global demand	Spatial demand		
Growth% p.a.	ETSA Utilities 10% PoE	Metropolitan	Rural	ETSA Utilities
2004–09	3.2%	2.9%	3.7%	3.2%
2009–15 excl PMA	3.3%	N/A	N/A	N/A
2009–15 incl PMA	2.5%	2.4%	3.1%	2.6%

Table 5.13 - Summary of post-model forecast adjustments for demand efficiency effects (MW)

Year	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Government programs						
Price and policy overlap	0.0	-0.1	-0.4	-1.2	-2.5	-4.6
REES	2.4	6.5	11.4	16.8	22.9	29.4
Thermal insulation programs	10.5	16.0	20.0	23.0	24.0	24.0
Small scale solar PV units	10.1	15.2	19.4	23.2	26.1	28.2
Appliance efficiency standards						
Residential lighting MEPS	2.5	3.3	3.9	4.5	4.7	4.8
Commercial lighting MEPS	10.0	13.5	16.0	18.2	19.2	19.6
Air conditioner MEPS	0.0	3.6	7.2	10.8	14.4	18.0
Television and set-top box MEPS	1.4	0.8	1.1	12.3	25.9	38.2
Appliance standby power	1.7	3.4	5.1	6.7	8.4	10.0
Total demand reduction	**34.6**	**58.2**	**79.7**	**110.3**	**139.1**	**163.6**
Annual demand reduction	**23.7**	**23.6**	**21.5**	**30.6**	**28.8**	**24.5**

Note: 2008–09 has a total demand reduction of 14.9 MW, which affects the 2009–10 annual demand reduction.

6

We do everything in our power to deliver yours

Forecast capital expenditure

6

FORECAST CAPITAL EXPENDITURE

In this chapter of the Revised Proposal, ETSA Utilities details its revised capital expenditure forecast for the 2010–2015 regulatory control period. ETSA Utilities has prepared this revised forecast to be consistent with the AER's Draft Decision for South Australia, with the exception of specific deviations which are discussed within the chapter, and which ETSA Utilities considers are required to achieve the capital expenditure objectives described within the National Electricity Rules (the Rules).

The specific deviations discussed within the chapter include:

- Capacity expenditure—revised low voltage planning criteria;
- Asset replacement expenditure—substation circuit breakers, substation transformers, planned poles expenditure, unplanned lines expenditure and general adjustment applied to asset replacement expenditure;
- Safety expenditure—substation fencing and security;
- Security of supply expenditure—network control;
- Customer connection expenditure—expenditure associated with resources for the new Negotiating Framework;
- Expenditure associated with equity raising; and
- Input cost escalation.

Additionally, the chapter discusses an error in Table 7.17 of the AER's Draft Determination.

ETSA Utilities has also provided additional information to the AER in support of this revised forecast in compliance with the requirements of the Regulatory Information Notice (RIN) dated 22 April 2009.

6.1

RULE REQUIREMENTS

In accordance with clause 6.5.7 (d) of the Rules, the AER has not accepted the total of the forecast capital expenditure proposed by ETSA Utilities for the 2010–2015 regulatory control period, and has set out its reasons for this decision in its Draft Decision for South Australia (the Draft Determination).

Clause 6.10.3 of the Rules sets out the circumstances under which ETSA Utilities may submit a Revised Proposal, which include the condition that ETSA Utilities may only make revisions to its Original Proposal so as to address matters raised by the AER in its Draft Determination.

6.2

ETSA UTILITIES' ORIGINAL PROPOSAL

In its Original Proposal, ETSA Utilities:

- proposed total forecast capital expenditure for the 2010–2015 regulatory control period of approximately $2.32 billion[102] (net, real, June 2010);
- described its capital governance framework and demonstrated alignment with the National Electricity Rules[103];
- detailed the process by which it developed its capital expenditure forecast for the 2010—2015 regulatory control period[104];
- described the key inputs to ETSA Utilities' expenditure forecasts[105]; and
- described the key variances between ETSA Utilities' forecast capital expenditure and 2008/09 base year[106].

6.3

THE AER'S DRAFT DETERMINATION

In the Draft Determination the AER concluded that ETSA Utilities' proposed capital expenditure was $638 million higher than that which the AER considered to be an efficient level. The AER's Draft Determination results in a 28 per cent reduction in ETSA Utilities' proposed capital expenditure.[107]

In particular, the AER considered that:[108]

- the proposed demand driven capital expenditure for the low voltage network program and major customer connections program do not reflect efficient costs;
- ETSA Utilities' proposed asset replacement expenditure does not reflect efficient costs;
- the proposed security of supply capital expenditure related to the Kangaroo Island network security project and elements of the network control project have not been demonstrated to be prudent and efficient; and
- ETSA Utilities' proposed safety related expenditure for the substation security fencing program and CBD aged asset replacement program do not reflect efficient costs.

6.4

ETSA UTILITIES' RESPONSE TO THE AER'S DRAFT DETERMINATION

In this Revised Proposal, ETSA Utilities has incorporated a number of the AER's findings with respect to its proposed capital expenditure for the 2010–2015 regulatory control period, including the AER's findings with respect to:

- expenditure on customer connection projects;
- expenditure on asset replacement of conductors;
- expenditure on the replacement program for aged assets in the Adelaide CBD area; and
- superannuation costs.[109]

However, ETSA Utilities has not incorporated the AER's findings in relation to the matters set out in Section 6.5 below.

102 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.108.
103 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.107.
104 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.99.
105 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.100.
106 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.109

107 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. vii.
108 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. viii.
109 ETSA Utilities' Revised Proposal also incorporates the AER's Draft Determination with respect to expenditure on the Kangaroo Island network security of supply project. The Revised Proposal removes the Kangaroo Island project from the forecast security of supply capital expenditure and instead includes a pass-through event for both the capital and operating expenditure associated with the failure of the 33kV undersea cable to Kangaroo Island if such an event were to materialise. See ETSA Utilities, *Revised Regulatory Proposal, Chapter 8*.

6.5

DEVIATIONS FROM THE DRAFT DETERMINATION

6.5.1 Capacity expenditure–revised Low Voltage Planning Criteria

ETSA Utilities' Original Proposal

In its Original Proposal, ETSA Utilities proposed an expenditure of $124.5 million (2008 dollars[110])[111] for the period associated with a change in its Low Voltage Planning Criteria. The change in Low Voltage Planning Criteria was in response to a risk review undertaken by ETSA Utilities to maintain ETSA Utilities' Distribution Code Obligations and reduce the risk of the re-occurrence of street transformer and mains outage events during peak demand periods similar to those experienced during the March 2008 and January 2009 heatwave conditions.

ETSA Utilities' forecast expenditure was determined by applying a state-wide After Diversity Maximum Demand (ADMD) of 4.5kVA per connected residential customer multiplied by the number of connected customers, and divided by the installed transformer capacity to determine the asset's utilisation. Ongoing load growth was applied at 2.5% per annum. The calculated asset utilisation was then compared to the criteria in Table 6.1 (based on ENA draft guidelines) to forecast replacement timing.

The program was costed by applying the replacement criteria in Table 6.1, and a transformer replacement unit cost of $29.2K (2008 dollars). The 2010 to 2020 (eleven year period) costs were calculated to determine an average annual transformer replacement cost associated with achieving the above utilisation criteria.

The allowance for low voltage mains upgrade was calculated based on a historical ratio of low voltage mains expenditure to low voltage transformer expenditure, increased by an annual historically derived growth factor.

A further annual allowance was included for the management of the low voltage network planning and field-based proactive monitoring.

PB's review of ETSA Utilities' Original Proposal

PB, in their Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, reached the following conclusions:

- the risk to ETSA Utilities as a consequence of heatwaves was overstated;[112]
- ETSA Utilities' proposed low voltage planning criteria are more conservative than those applied by other Australian DNSP's;[113]
- ETSA Utilities' load assumptions and the use of a single ADMD figure to forecast the number of overloaded transformers resulted in the overstatement of the volume of transformer capacity augmentations required;[114]
- the annual $0.8 million (2008 dollars) proposed for the management of the low voltage network planning and field-based proactive monitoring was removed on the basis that such costs should be operating expenditure;[115]
- the proposed capital expenditure for the program was not prudent and efficient for the above reasons;[116] and
- despite the above, recent heatwaves have resulted in constraints that a prudent and efficient network operator would seek to address and an allowance was recommended for an estimated 'business as usual' level of expenditure, plus an allowance for 51 transformer replacements per annum (estimated on recent heatwave transformer failures).[117]

Table 6.1: ETSA Utilities' Original Proposal Low Voltage Transformer Replacement Criteria

Transformer Type	Transformer capacity utilisation 2010–2014	Transformer capacity utilisation 2015–2020
Pole Mount	130%	100%
Padmount	100%	100%

110 All expenditure noted as 2008 dollars within this Revised Proposal chapter includes corporate overheads which are subsequently removed in ETSA Utilites' modelling. This is explained further in Attachment F.11.

111 ETSA Utilities' Original Proposal, *CX001*.

112 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p32.

113 PB, Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, p35.

114 PB, Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, p36.

115 PB, Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, p37.

116 PB, Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, p36.

117 PB, Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, p37.

The AER's Draft Determination

The AER noted PB's assessment that the risk assessment underpinning the Low Voltage Network Upgrade Program overstated the risk, and that ETSA Utilities' proposed low voltage planning criteria were more conservative than those applied by other Australian DNSPs.[118]

The AER agreed with PB that the full scope of the proposed program was not appropriately justified given ETSA Utilities' use of inferred rather than actual load assumptions and the resulting impact on volume forecasts.[119]

The AER considered that PB's approach for calculating an allowance for low voltage network augmentation represented a reasonable approach to determining a prudent and efficient level of expenditure, in the absence of information supporting the full scope of the program. Accordingly, the AER's Draft Determination reduced the capacity related capital expenditure forecast in ETSA Utilities' Original Proposal by $92 million (2008 dollars).

ETSA Utilities' response to the AER's Draft Determination

In response to the issues raised by the AER in the Draft Determination, ETSA Utilities engaged Evans and Peck to provide a technical expert opinion regarding the appropriateness of ETSA Utilities' low voltage planning approach.

Evans and Peck's experience in this area includes the following:

- undertaking the analysis which formed the basis of Energy Australia's submission to the AER in relation to distribution substation and low voltage distributor requirements; and
- on behalf of the Queensland Competition Authority, reviewing Energex and Ergon Energy's Annual Network Management Plans on an annual basis for a number of years, including aspects relating to low voltage planning.

Evans and Peck's scope was to review the methodology and model employed by ETSA Utilities to forecast the distribution transformers anticipated to be overloaded for the regulatory period. In particular, Evans and Peck considered three aspects of ETSA Utilities' Original Proposal and subsequent review by PB, being:

- whether or not the temperature conditions experienced by ETSA Utilities in 2009 can be considered unusual or extreme;
- the approach taken to the determination of equipment rating by ETSA Utilities; and
- the approach taken to the determination of utilisation levels of transformers, and specifically the appropriateness of the ADMD value being adopted by ETSA Utilities.

Evans and Peck's findings are discussed in the categories below. The final report is provided as Attachment F.2.

Risk

Data from the Bureau of Meteorology was reviewed in order to assess the probability of temperature conditions similar to those experienced in 2009. Evans and Peck concluded that the need to cope with such weather events as the temperature conditions experienced in 2009, whilst at the high end, are within 'business as usual' expectations from a planning perspective. As a consequence, Evans and Peck indicated that the risk faced in the low voltage network was high, and should not be revised to medium or low as indicated by PB.[120]

Low Voltage Planning Criteria

Evans and Peck agreed with PB that ETSA Utilities' Low Voltage Planning Criteria erred on the conservative side and recommended a revised set of planning criteria as indicated in Table 6.2.[121]

Table 6.2: Evans and Peck recommended Low Voltage Transformer Replacement Criteria

Transformer type	Transformer capacity utilisation
Pole Mount	130%
Padmount	120%

118 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p134
119 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p134
120 Attachment F.2: Evans and Peck, *ETSA Utilities Low Voltage Planning Review*, p2
121 Attachment F.2: Evans and Peck, *ETSA Utilities Low Voltage Planning Review*, p12

Load assumptions and use of a single ADMD figure to forecast number of overloaded transformers

Evans and Peck considered that, in the absence of data to support direct recording of peak loads, the ADMD multiplied by Count of Customers approach provides an appropriate methodology for screening overload situations.[122]

ETSA Utilities provided Evans and Peck with 2009 Heatwave Test sample data collected through its Demand Management Trials and permanently monitored transformers.[123] As indicated in ETSA Utilities' response to PB,[124] the heatwave tests associated with Demand Management and permanent monitoring are considered a random sample as the meters were installed for purposes other than targeted peak load monitoring. However, ETSA Utilities considers that the sample is conservatively low as an indication of the 2009 average ADMD per customer because the location of Glenelg—the main trial area—is reflective of an established older suburb and is coastal, and therefore subject to natural night-cooling breezes. The greater metro average is anticipated to be higher than the sample average due to the impact of new housing design (which aims for overall energy efficiency and not peak temperature efficiency) and a lack of coastal breezes.

Evans and Peck analysed the sample data provided by ETSA Utilities and recommended an average ADMD of 3.86kVA per customer be adopted for planning purposes.[125]

Evans and Peck also reviewed ETSA Utilities' forecast replacement growth rate and revised it from 2.5% to 2.1% on the basis that some of the 2.5% included new customers in new estates and therefore should not be included in the replacement growth rate.[126]

Costing of program

Evans and Peck costed the transformer replacement program utilising ETSA Utilities' spreadsheet[127], the revised Low Voltage Planning Criteria, revised average ADMD per customer of 3.86 kVA and revised replacement growth rate of 2.1%. This resulted in transformer replacement costs of $12.5 million per annum (2008 dollars). Evans and Peck believe this estimate to be at the low end of ETSA Utilities' requirements for reasons detailed within the report.[128]

Utilising Evans and Peck's revised estimate for transformer replacement, ETSA Utilities has applied a historical ratio of low voltage mains expenditure to transformer expenditure, with a 2.1% per annum growth rate (for consistency with the ADMD growth rate) to derive the forecast low voltage mains expenditure.

ETSA Utilities has also re-instated the $0.8 million (2008 dollars) per annum allowance for low voltage planning and field-based proactive load monitoring on the basis that ETSA Utilities' historical accounting practice is to capitalise these activities. No operating expenditure allowance has been included for this activity within ETSA Utilities' Revised Proposal.

Volume of transformer replacements

In order to verify the prudence of the proposed volume of transformer replacements within ETSA Utilities' Revised Proposal, the 2009 heatwave data was analysed and compared to the revised Low Voltage Planning Criteria. The transformer loadings were calculated at 2009 heatwave levels and at 2015 forecast levels, utilising 2.1% per annum growth. The number of transformers for replacement at 2009 heatwave levels and 2015 forecast was divided by the sample size in order to determine an indicative percentage of population requiring replacement. This analysis, the results of which are summarised in Table 6.3, is included in Attachment F.3 [129]

Table 6.3: Summary of analysis of ETSA Utilities' heatwave data

Sample	2009 Replacements (% sample)	2009-2015 Replacements (% sample)
168 point sample	16%	30%
94 point sample	14%	30%

122 Attachment F.2: Evans and Peck, *ETSA Utilities Low Voltage Planning Review*, p15
123 ETSA Utilities, *SI204 EM75DM.xls*
124 ETSA Utilities, *PB.ETS.EM.75*
125 Attachment F.2: Evans and Peck, *ETSA Utilities Low Voltage Planning Review*, p19
126 Attachment F.2: Evans and Peck, *ETSA Utilities Low Voltage Planning Review*, p16
127 ETSA Utilities, *SI12 PB.ETS.EM.31 LV modelling spreadsheet.xls*
128 Attachment F.2: Evans and Peck, *ETSA Utilities Low Voltage Planning Review*, p18
129 ETSA Utilities, *Attachment F.3–Heatwave Test Sample Analysis.xls*

The percentage of the sample transformer population requiring replacement is compared to ETSA Utilities' Revised Proposal and the AER's Draft Determination in Table 6.4. The population size for metropolitan transformers is 12,451.[130]

As can be seen in Table 6.4, ETSA Utilities' Revised Proposal is in line with the transformer replacements predicted by the sample data.

ETSA Utilities notes that the low voltage transformer replacement percentages outlined in Table 6.4 differ from those set out in its Original Proposal.

In preparing this Revised Proposal, ETSA Utilities has undertaken a detailed analysis of the matters raised by PB in relation to ETSA Utilities' low voltage planning approach. As part of this analysis, ETSA Utilities engaged Evans and Peck to review the approach ETSA Utilities took in preparing its regulatory proposal. As outlined above, Evans and Peck's review recommended certain changes to ETSA Utilities' low voltage planning approach. These recommendations have been incorporated into this Revised Proposal and account for the difference between the percentages outlined in Table 6.4 and the Original Proposal.

ETSA Utilities' Revised Proposal

Based on the costing approach described above, the expenditure proposed for the period is $73.1 million (2008 dollars). The full costing of the program is documented in Attachment F.4.[131]

ETSA Utilities considers that the capital expenditure detailed in this Revised Proposal arising from the change in its Low Voltage Planning Criteria is consistent with clause 6.5.7 of the Rules.

The expenditure is required in order to achieve the capital expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services.

The work undertaken by Evans and Peck demonstrates that the forecast capital expenditure reasonably reflects the capital expenditure objectives, in particular, that the forecast expenditure is prudent and efficient and reflects a realistic expectation of demand forecasts.

Revised Proposal

In this Revised Proposal, ETSA Utilities has amended its forecast associated with low voltage planning and augmentation, which is based on Evans and Peck's recommended transformer replacement programme, ETSA Utilities' historical ratio of low voltage mains expenditure with growth of 2.1% per annum, and the reinstatement of the Original Proposal allowance for low voltage planning and field-based proactive monitoring.

ETSA Utilities' amended forecast results in a positive adjustment of approximately $39 million (real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.

Table 6.4: Comparison of % population of low voltage transformer replacements(1)

	Replacement 2010–2015 (% Population)
ETSA Utilities' Original Proposal	29%
AER Draft Determination	2%
ETSA Utilities' Revised Proposal	17%(2)
Forecast based on representative sample	14% to 30%

Note:

(1) Attachment F.3: ETSA Utilities, *Heatwave Test Sample Analysis.xls, TransfReplacementsPopulation worksheet*

(2) This calculation is based on Evans and Peck's calculations that the budget for transformer replacements should be set at approximately $12.5 million (2008 dollars) per year. ETSA Utilities estimates that each transformer replacement costs approximately $29.2K (2008 dollars). Therefore, a transformer expenditure of $12.5 million (2008 dollars) equates to 428 transformers per annum, or 2,140 over the regulatory period (approximately 17 per cent).

130 As modelled by ETSA Utilities and referenced in PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p34, Table 4.5

131 ETSA Utilities, *Attachment F.4–Capital Expenditure Costing.xls, LV Augmentation Worksheet*

6.5.2
Asset replacement expenditure—circuit breakers

ETSA Utilities' Original Proposal
In the Original Proposal, ETSA Utilities proposed expenditure of $45.0 million (2008 dollars)[132] for the period associated with asset replacement of circuit breakers.

ETSA Utilities' forecast expenditure was determined by:
- for unplanned asset replacement, applying a forecast based on historical failure rates; and
- for planned asset replacement, assessing a probability of failure and the consequence of failure.

For those units without known condition issues, consequence of failure was considered in conjunction with age, to develop an age-based replacement forecast.

ETSA Utilities' asset replacement programme was based on the following numbers of circuit breaker replacements for the six calendar years from 2010 to 2015:
- 12 circuit breakers associated with unplanned replacement;
- 55 circuit breakers associated with planned replacement, on the basis of known condition or problems; and
- 106 circuit breakers associated with planned replacement, on the basis of age.

PB's review of ETSA Utilities' Proposal
PB, in their Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, reached the following conclusions:
- The circuit breaker asset replacement expenditure associated with unplanned asset replacement was considered efficient due to its basis on historical failure rates.[133]
- The planned circuit breaker asset replacement associated with known condition or type problems was generally considered efficient on the basis that ETSA Utilities' maintenance practices favour repair rather than replacement, and that the planned replacements were staged over the period to manage the risk of non-repairable failure.[134]
- ETSA Utilities has in place a well-established strategy of condition monitoring and diagnostic testing of circuit breakers, adequate management of spares, and the ability to isolate and bypass a unit in the event of failure.[135] PB concluded that, as the existing strategy is prudent and effective, the proposed age-based replacements were not required and recommended that 106 of the 173 planned circuit breaker replacements be removed from the program.[136]

The AER's Draft Determination
The AER noted PB's comments that ETSA Utilities has a circuit breaker population, some of which are 70 years of age and that the current condition and performance monitoring is sufficient to manage the efficient replacement of its assets. The AER considered that because ETSA Utilities has in place an effective substation circuit breaker condition based replacement strategy, the provision of age based replacement of circuit breakers, in addition to the condition based replacement is not prudent or efficient.[137]

The AER agreed with PB that the 106 age-based planned circuit breaker replacements be removed from the forecast.[138]

ETSA Utilities' response to the AER's Draft Determination

Summary
ETSA Utilities' Revised Proposal is based on the following:
- ETSA Utilities' population of substation circuit breakers is well documented at an individual circuit breaker level.[139]
- ETSA Utilities' Original Proposal for planned circuit breaker replacement was documented at the individual circuit breaker level. A circuit breaker planned for replacement within the period was either planned for replacement on the basis of existing condition or age, thus ensuring that there was no double-counting in planned expenditure.[140]
- A number of ETSA Utilities' circuit breakers have reached their maximum expected life, beyond which the risk of failure in service increases unacceptably.
- The consequence of in-service failure of circuit breakers, combined with the increased risk, makes planned replacement of aged circuit breakers without existing condition problems an appropriate strategy for ETSA Utilities.
- The planned replacement of aged circuit breakers needs to begin in the forecast regulatory period in order to manage the associated risk and to stage the workload.

132 ETSA Utilities' Original Proposal, *CX001*.
133 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p59.
134 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p59.
135 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p59.
136 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p60.
137 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p144.
138 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p144.
139 ETSA Utilities, *Asset Management Plan 3.2.05 2009 to 2020 Substation Circuit Breakers*, p58 to p86.
140 ETSA Utilities, *Asset Management Plan 3.2.05 2009 to 2020 Substation Circuit Breakers*, p58 to p86.

Age as a basis for circuit breaker replacement

In response to the issues raised by the AER in the Draft Determination, ETSA Utilities engaged EA Technology to provide a technical expert opinion on the significance of asset age in planning effective and efficient asset replacement of substation circuit breakers.

EA Technology's experience in this area includes the following:

- working with UK DNSPs to study degradation and failure modes of older circuit breakers with the express purpose of building an understanding of issues that will ultimately define end of life;[141] and
- developing and applying the process known as Condition Based Risk Management (CBRM), which has been implemented in over 30 companies. In this regard, ETSA Utilities notes that, in Energex's Draft Determination, the AER accepted PB's advice that the use of the CBRM model is likely to lead to prudent and efficient asset replacement.[142]

EA Technology reviewed ETSA Utilities' proposed circuit breaker replacement programme and concluded the following[143]:

- Experience with similar circuit breakers in the UK supports ETSA Utilities' view that the maximum expected life for such assets is in the region of 60 years. EA Technology's experience with other Australian network operators also supports this conclusion.
- Based on the age of ETSA Utilities' existing circuit breakers and available engineering expertise, it is expected that their reliability will significantly decrease over the next 5-10 years.
- In addition to the risk of individual breaker reliability, obsolescence issues and the potential for compounded risk with many similar breakers in close proximity add to the overall risk.
- Failure to implement an effective replacement programme, with a prudent start date, would give rise to a level of risk that would generally be regarded as unacceptable by electricity companies.
- Application of a more detailed condition and risk process would almost certainly confirm the need for significant replacement over the next 5-10 years.

EA Technology further indicated that there are few circuit breakers over 65 years of age still in service in the UK and that, those that are still in service, are currently being replaced.[144]

EA Technology's report is provided as Attachment F.5 to this Revised Proposal.

141 Attachment F.5: EA Technology, *The significance of asset age in estimating remnant life/end of life for substation plant*, p5 to p8.

142 AER, *Queensland Draft distribution determination 2010–11 to 2014–15*, p110.

143 Attachment F.5: EA Technology, *The significance of asset age in estimating remnant life/end of life for substation plant*, Summary.

144 Attachment F.5: EA Technology, *The significance of asset age in estimating remnant life/end of life for substation plant*, p8.

ETSA Utilities' circuit breaker population

ETSA Utilities has reconstructed the data associated with the reductions recommended in PB's review[145]. Figures 6.1 and 6.2 summarise the circuit breaker age profile at the time of formulating the circuit breaker Asset Management Plan (2008) compared to the circuit breaker populations in 2015 of both ETSA Utilities' Original Proposal and PB's recommendation. Only those circuit breakers greater than 50 years of age have been included.

Fig 6.1: ETSA Utilities' circuit breaker population 50–60 years old—comparison of the ETSA Utilities and PB forecasts to 2008 population

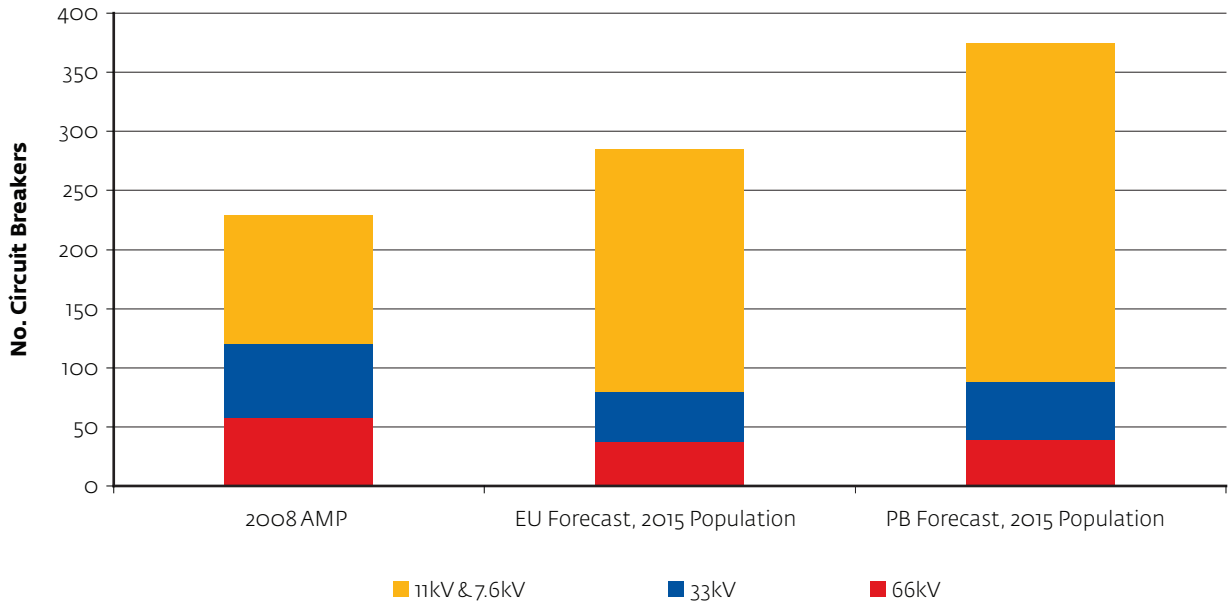
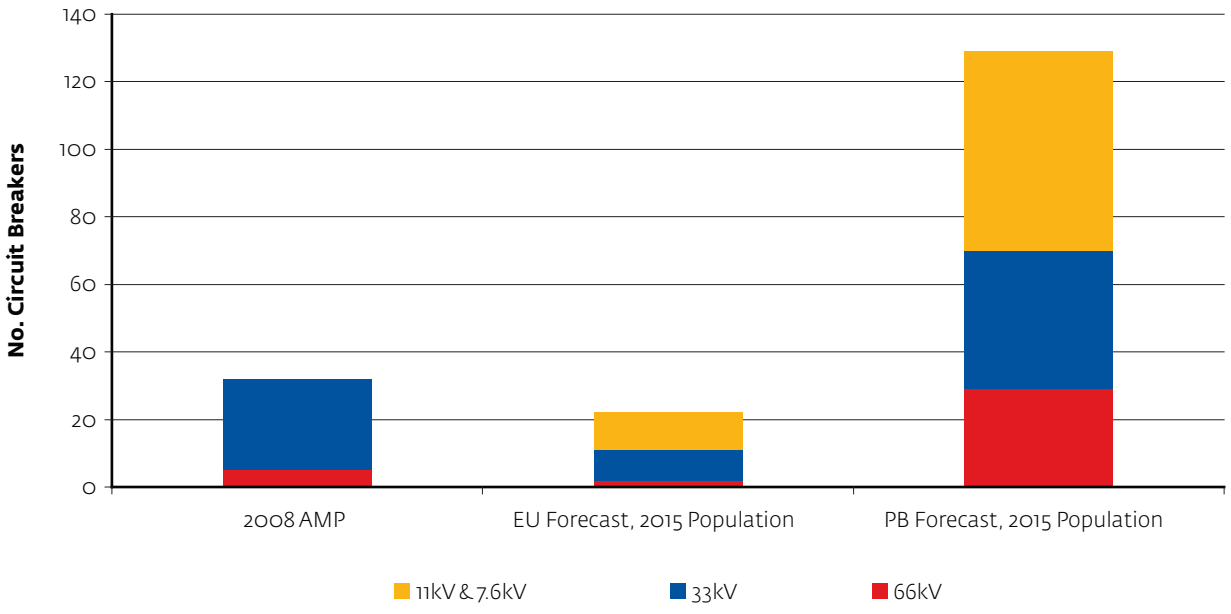


Fig 6.2: ETSA Utilities' circuit breaker population 60-70 years old—comparison of the ETSA Utilities and PB forecasts to 2008 population



145 ETSA Utilities, *11 and 7.6kV CB Forecast age profile.xls, 33kV CB Forecast age profile.xls, 66kV CB Forecast age profile.xls, CB Population Summary.xls*

ETSA Utilities currently has 17 circuit breakers in service that are greater than 70 years old. Both the PB and ETSA Utilities forecasts include the replacement of these circuit breakers. Figures 6.1 and 6.2 demonstrate that:

- PB's proposal would significantly increase the number of circuit breakers which are older than 60 years. As noted above, EA Technology's report indicates that the risk of failure increases significantly after circuit breakers reach 60 years of age. In these circumstances, ETSA Utilities considers that adoption of PB's proposal would significantly increase the risk of in-service failures.
- ETSA Utilities' circuit breaker population is of an age whereby deferral of replacements into future regulatory periods will compound the numbers of aged circuit breakers, and will result in a situation whereby the risk and the workload associated with planned and unplanned circuit breaker asset replacement increase to unacceptable levels.

Consequence of in-service failure of circuit breakers

The potential consequences of in-service failures of a high voltage circuit breaker and/or its associated protection system include the following:

- fire and/or irreparable damage of primary assets (line or transformer);
- switch-room fire;
- bushfire start;
- potential death or injury resulting from personnel in proximity to explosive failure; and
- widespread customer outages.

In common with other DNSPs, ETSA Utilities has experienced a number of the above incidences associated with in-service circuit breaker failure.

PB infer in their review of ETSA Utilities' circuit breaker asset replacement programme that circuit breaker asset replacement can continue to be adequately managed, without age-based replacement, through the existing practices of:[146]

- condition monitoring and diagnostic testing of problematic circuit breakers;
- ensuring adequate spares holding; and
- isolating and bypassing a unit in the event of a failure.

With regard to the above strategies, ETSA Utilities makes the following comments:

- These strategies are adequate at current failure rates. However, as discussed above, EA Technology's Report indicates that the reliability of circuit breakers greater than 60 years old will significantly decrease. Given its increasing population of these circuit breakers, ETSA Utilities considers that the risk of circuit breaker failures will significantly increase in the future.
- Obsolescence issues associated with circuit breakers greater than 60 years old mean that adequate spares holding becomes less viable as a strategy—manufacturers often do not exist for these circuit breakers and parts cannot be sourced.
- The ability to isolate and bypass a unit in the event of a failure is currently not an option under peak conditions (ie the circuit breakers are not redundant devices). Furthermore, the strategy of isolating and bypassing units is not suitable in the event of multiple failures. As discussed above, EA Technology's Report indicates that multiple failures are more likely to occur if a number of older circuit breakers are located in close proximity to one another.
- With the increased probability of failure associated with circuit breakers greater than 60 years old, and the potential consequences listed above, the business risk associated with retaining these circuit breakers in service is unacceptable.

ETSA Utilities' Revised Proposal

On the above basis, ETSA Utilities' Revised Proposal reinstates all proposed age-based circuit breaker replacements where the circuit breaker will be 60 years old, or older, in 2015 (in alignment with EA Technology's maximum expected life for circuit breakers).

ETSA Utilities' Revised Proposal is costed in Attachment F.4.[147] The expenditure proposed for the period is $36.9 million (2008 dollars).

ETSA Utilities considers that the capital expenditure detailed in this Revised Proposal in connection with the replacement of circuit breakers is consistent with clause 6.5.7 of the Rules.

The expenditure is required in order to achieve the capital expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services.

The advice given by EA Technology and material supplied by ETSA Utilities demonstrates that the forecast capital expenditure reasonably reflects the capital expenditure objectives, in particular, that the forecast expenditure reflects the efficient costs of achieving the capital expenditure objectives and the costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capital expenditure objectives.

146 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p59

147 ETSA Utilities, *Attachment F.4—Capital Expenditure Costing.xls, CircuitBreaker Worksheet*

Revised Proposal

In this Revised Proposal ETSA Utilities has amended its forecast associated with circuit breaker asset replacement, which is based on the reinstatement of planned age-based circuit breakers greater than 60 years old.

ETSA Utilities' revised forecast results in a positive adjustment of approximately $91 million (real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.[148]

6.5.3 Asset replacement expenditure—substation transformers

ETSA Utilities' Original Proposal

In its Original Proposal, ETSA Utilities proposed expenditure of $36.2 million (2008 dollars)[149] for the regulatory control period associated with asset replacement of substation transformers. ETSA Utilities' forecast expenditure was determined:

- for unplanned asset replacement, applying a forecast based on historical failure rates; and
- for planned asset replacement, on the assessed probability of failure and the consequence of failure. For those units without known condition issues, age was utilised as a predictor of the probability of failure.

ETSA Utilities' asset replacement programme for the forecast regulatory period was based on the following numbers of substation transformer replacements:

- 20 transformers associated with unplanned replacement;
- 9 transformers associated with planned replacement, on the basis of known condition or problems; and
- 19 transformers associated with planned replacement, on the basis of age.

PB's Review of ETSA Utilities' Proposal

PB, in their Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, reached the following conclusions:

- The transformer asset replacement expenditure associated with unplanned asset replacement was not considered prudent and efficient on the basis that the failure rates did not align with historical levels. The failure rate for 66kV (>20MVA) transformers was adjusted from one failure per annum to three failures in five years, a reduction of two transformers. The failure rate for 66kV (5-20MVA) transformers was adjusted from one failure per annum to four failures in five years, a reduction of one transformer.[150]
- The planned transformer asset replacement associated with known condition or type problems was adjusted. The full expenditure associated with the Tyree E465 transformer replacements was not considered to be justified as it was considered to be based on an arbitrary adjustment to the expected transformer life. The Croydon transformer replacements were retained and the remaining Tyree E465 transformers removed from the capex proposal.[151]
- The planned transformer asset replacement associated with age based replacement was not considered prudent and efficient and was removed on the basis that ETSA Utilities has in place adequate condition monitoring and well-considered spares management, and that the replacement schedule will ultimately be determined by condition and performance monitoring and unplanned transformer failures.[152]

The AER's Draft Determination

The AER noted PB's analysis that ETSA Utilities' substation power transformer replacement capex will be based on condition rather than age, and therefore concluded that the inclusion of the age based replacements is unsupported.[153] The AER considered that ETSA Utilities had not provided sufficient information to justify the increase in unplanned 66kV power transformer replacements and the replacement of the Tyree E465 class transformers and accepted PB's adjustments to these categories.[154]

148 Includes all asset replacement adjustments in this Revised Proposal chapter.

149 ETSA Utilities' Original Proposal, *CX001*

150 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p62

151 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p62

152 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p61

153 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p144

154 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p145

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities' Revised Proposal is based on the following, in addition to the transformer replacements allowed for within the AER's Draft Determination:

- Reinstatement of the 66kV (5-20MVA) transformer failure rate to one per annum based on the fact that ETSA Utilities has experienced nine transformer failures of this type within the last nine years, including five failures within the last five years and three failures in 2009 alone.[155] ETSA Utilities' Revised Proposal therefore includes one additional 66kV (5-20MVA) transformer to revise the failure rate from four in five years to one per annum over the next regulatory control period.
- Increased spares holding for CBD 66kV to 33kV transformers.[156] These transformers are the only supply to the CBD 33kV system, which supplies 20% of CBD load and all of the major department stores in Adelaide. ETSA Utilities' Original Proposal had included replacement of these transformers within the next period due to their age (they will be 60 years old in 2015) and consequence of failure. ETSA Utilities holds no spares for these transformers and based on the elimination of these transformer replacements from the capital expenditure forecast, ETSA Utilities has included in the Revised Proposal an amount for the purchase of a spare for these transformers.
- The reinstatement of the replacement of the remaining Tyree E465 class transformers on the basis that two of seven of ETSA Utilities' population of this model of transformer have failed prematurely[157], and the recommendation of an independent expert which confirms a design fault within this model of transformer.[158]
- No planned age-based transformer replacements have been included in ETSA Utilities' Revised Proposal.

ETSA Utilities' Revised Proposal

ETSA Utilities' Revised Proposal is costed in Attachment F.4.[159] The expenditure proposed for the period is $23.3 million (2008 dollars).

ETSA Utilities considers that the capital expenditure detailed in this Revised Proposal in connection with the replacement of substation transformers is consistent with clause 6.5.7 of the Rules.

The expenditure associated with the replacement of substation transformers is required in order to achieve the capital expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services.

The material that ETSA Utilities has provided to the AER in relation to the condition issues and spares strategies of its transformers and experience with failure rates of existing transformers demonstrates that the forecast capital expenditure reasonably reflects the capital expenditure objectives. In particular, the forecast expenditure reflects the efficient costs of achieving the capital expenditure objectives and the costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capital expenditure objectives.

Revised Proposal

In this Revised Proposal, ETSA Utilities has amended its forecast associated with transformer asset replacement, which is based on, in addition to those transformers allowed for within the AER's Draft Determination, the adjustment of the 66kV (5-20MVA) transformer failure rate, an additional spare for CBD 66kV to 33kV transformers, and the reinstatement of the replacement of the remaining Tyree E465 class transformers.

ETSA Utilities' revised forecast results in a total asset replacement positive adjustment of approximately $91 million (real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.[160]

155 ETSA Utilities, *AMP 3.0.01 Fig 2.2*, Provided with ETSA Utilities' Original Proposal as CX100.

156 ETSA Utilities, AMP 3.2.01, Attachment 2. Provided with ETSA Utilities' Proposal as CX113. The referenced transformers are East Tce TF1 ST839, East Tce TF2 ST837, Hindley St TF1 ST1173.

157 ETSA Utilities, *AMP 3.2.01*, p25. Provided with ETSA Utilities' Original Proposal as CX113.

158 R Park, *Failed Tyree Transformers 21MVA 66/11kV 7 March 2003*.

159 ETSA Utilities, *Attachment F.4—Capital Expenditure Costing.xls, Transformers Worksheet*.

160 Includes all asset replacement adjustments in this Revised Proposal chapter.

6.5.4
Asset replacement expenditure—poles

ETSA Utilities' Original Proposal

In its Original Proposal, ETSA Utilities proposed expenditure of $38.0 million (2008 dollars)[161] for the period associated with asset replacement of stobie poles.

ETSA Utilities' forecast expenditure was determined based on a normal distribution model of pole age, average life, and corrosion zones. The key inputs to the model were determined as follows:

- pole age and population by corrosion zone were implied from manufacturing history and Geographic Information System (GIS) data; and
- average pole life was determined based on available actual average life data.

The forecast between poles requiring plating and those requiring replacement was based on the evaluation of the percentage of poles exceeding their modelled failure age, and the extent to which the modelled failure age had been exceeded.

The modelled results were retrofitted to 2006 actual pole data.

PB's Review of ETSA Utilities' Proposal

PB, in their *Review of ETSA Utilities Regulatory Proposal* for the period July 2010 to June 2015, reached the following conclusions:

- The total volume of pole failure forecasts is efficient based on comparison with PB's analysis of ETSA Utilities' pole defect history.[162]
- The strategy of increased focus on pole refurbishment is prudent.[163]
- The forecast ratio of high corrosion zone pole replacements to total pole treatments (80%) was not justified in comparison to the historically achieved ratio or the medium zone corrosion forecast. An adjustment was made to the high corrosion zone pole replacement forecast so that the ratio of pole replacements to treatments was consistent with the medium corrosion zone forecast ratio of pole replacements (15%).[164]

The AER's Draft Determination

The AER accepted PB's advice that ETSA Utilities' replacement rate should decrease to reflect efficiency improvements, not increase. The AER considered that a reduction from 80% to 15% for high corrosion zone replacements was prudent and efficient.[165]

ETSA Utilities' response to the AER's Draft Determination

In developing its forecast of replacements as a percentage of total pole treatments (replacements and plating refurbishments), ETSA Utilities considered the output from the model only and the number of poles which were within the age criteria as defined by the model (refer Figures 6.3, 6.4 and 6.5). Within the high corrosion zone, due to the high number of forecast poles that are well advanced within the modelled age failure criteria, the proportion of replacements as a percentage of treatments would be significantly higher than in the low and medium corrosion zones.

In establishing the forecast ratio of pole replacements to treatments (pole replacements and pole plating), ETSA Utilities did not consider the ratios achieved from historical condition assessments. These are graphed in Figure 6.6. As can be noted, the ratio of pole replacements to treatments has been relatively stable for the last three years for all corrosion zones, and is not decreasing. ETSA Utilities agrees with PB that, in determining the forecast of future ratios of pole replacements to treatments, a relevant factor to be considered are the ratios achieved from historical condition assessments.

It should be noted that ETSA Utilities formalised and changed its inspection cycle for the high corrosion zone in 2007 / 2008 to a five yearly cycle (ie 20% of the population are inspected in any one year). Therefore, it is not expected to see improvements to the current ratio of pole replacements to treatments until the completion of the first cycle of inspections (ie mid next regulatory period). This is based on a reasonable assumption that the uninspected population of poles are likely to be in the same condition (and therefore require the same proportion of replacements) as the inspected population. In this Revised Proposal, ETSA Utilities has therefore revised its forecast of the ratio of replacements to treatments in the high corrosion zone to be 31% (as per the historical three year average) until the completion of the first five yearly inspection cycle, in the middle of the next regulatory period. Thereafter, ETSA Utilities has forecast an improvement in the ratio of replacements to treatments in the high corrosion zone to 15%, in accordance with the AER's Draft Determination. This approach is appropriate for the high corrosion zone, given its relatively low population (est 34,000).

Within the low and moderate corrosion zones, ETSA Utilities has re-forecast the ratio of replacements to treatments to be consistent with the historical information in Figure 6.6 and to be largely consistent with the approach for the high corrosion zone forecast. This approach is based on a reasonable assumption that the uninspected population of poles is likely to be in the same condition as the inspected population. The limited location information associated with ETSA Utilities' historical inspection records, the relatively large populations of poles within the moderate and low corrosion zones (215,000 and 474,000 respectively), and the longer ten year inspection cycle mean that ETSA Utilities is unlikely to see the improvement in the ratio of pole replacements to treatments, which has been forecast in the high corrosion zone, until after the end of the next regulatory period.

The calculations associated with the Revised Proposal pole treatments are included in Attachment F.6.

161 ETSA Utilities' Original Proposal, *CX001*.

162 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p65.

163 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p65.

164 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p66.

165 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p145.

Fig 6.3: Modelled low corrosion zone stobie pole population and failure rate

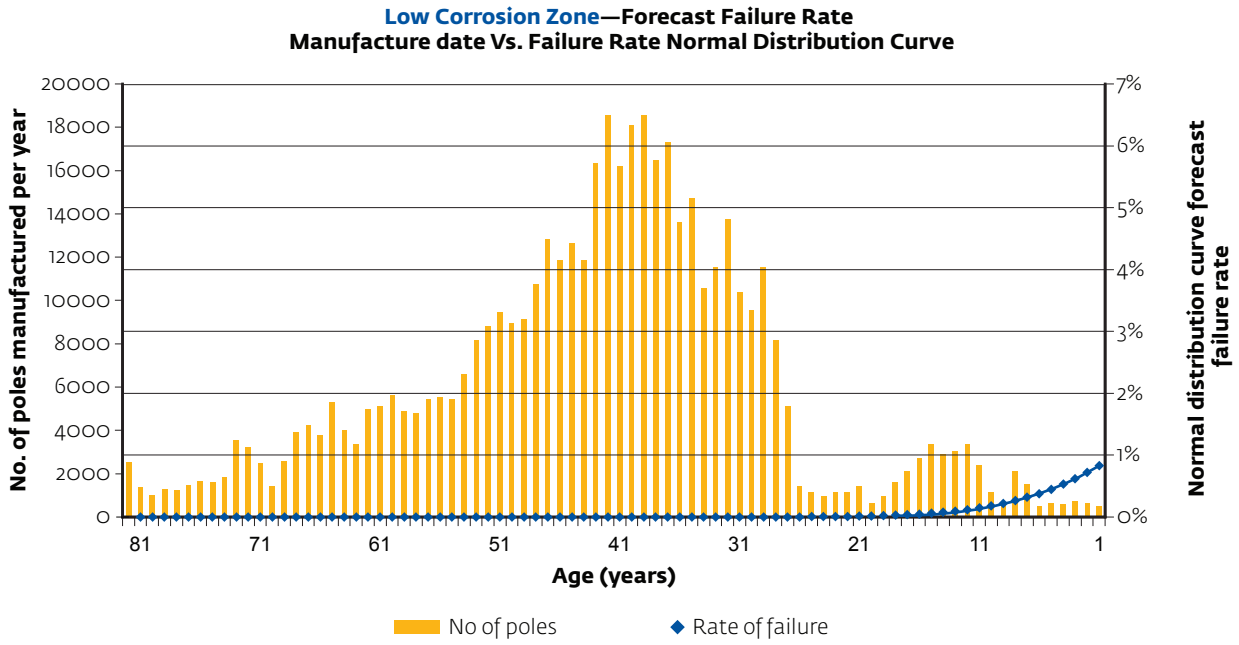


Fig 6.4 Modelled moderate corrosion zone stobie pole population and failure rate

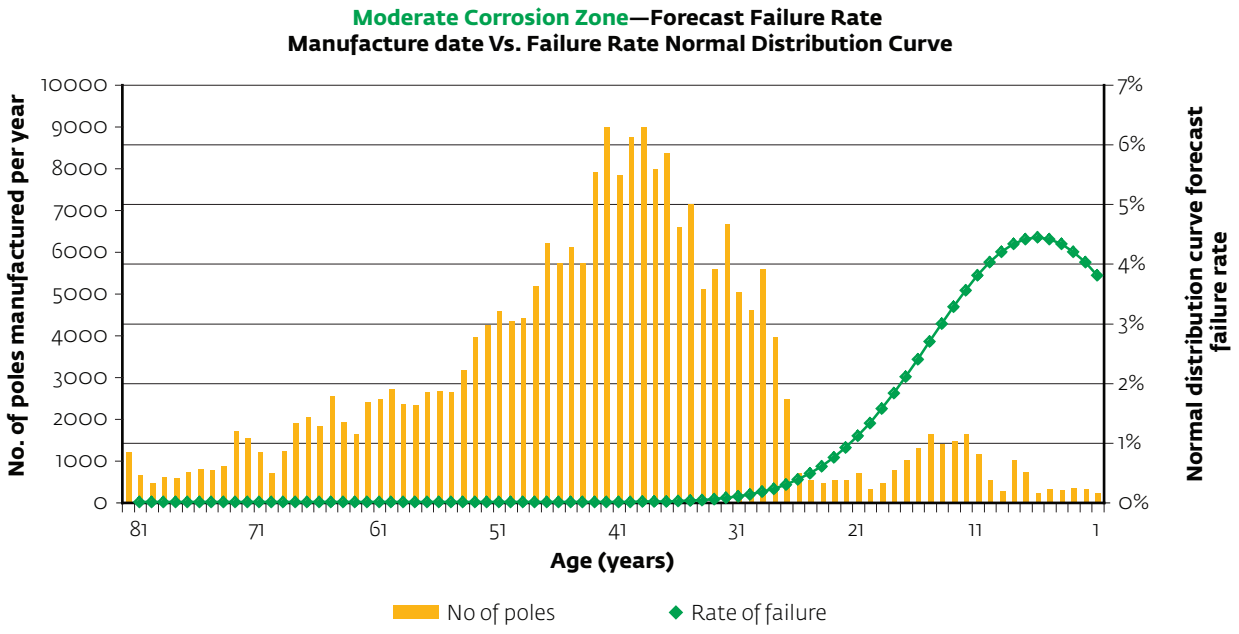


Fig 6.5 Modelled high corrosion zone stobie pole population and failure rate

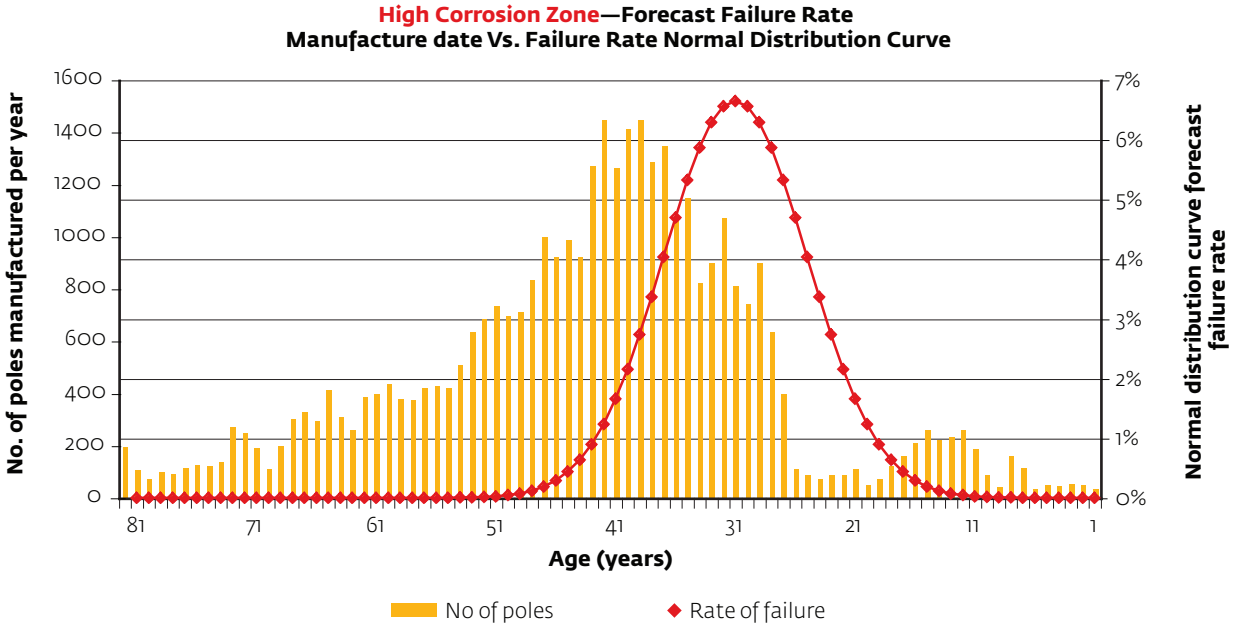
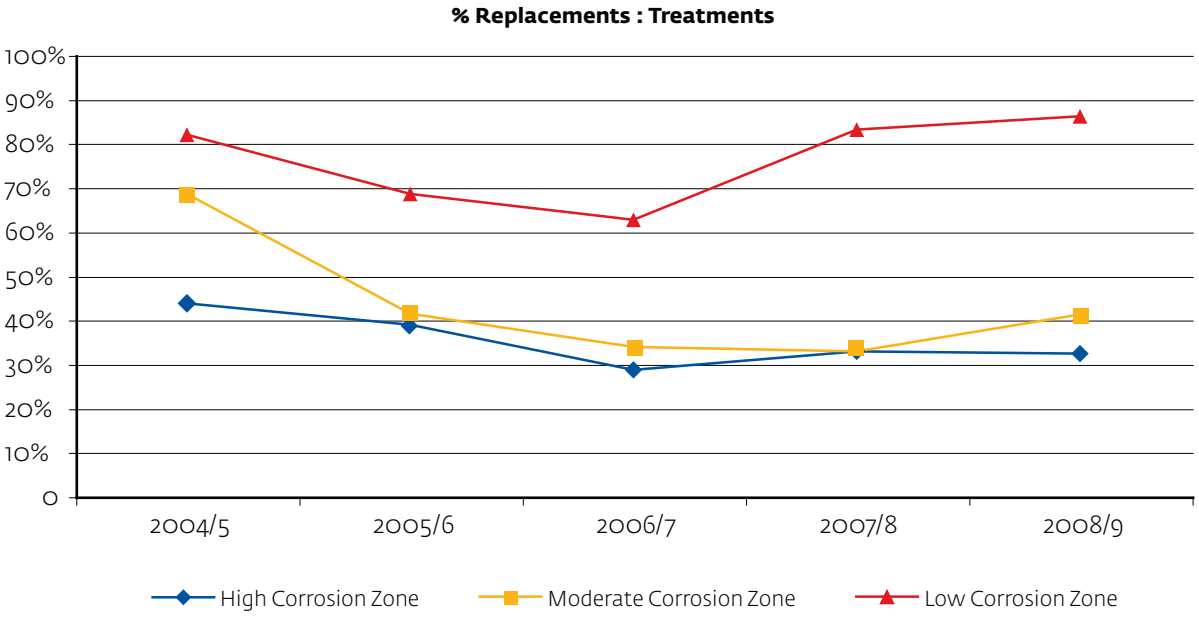


Fig 6.6 Actual ratio pole replacements to total pole treatments



ETSA Utilities' Revised Proposal

ETSA Utilities' Revised Proposal is based on maintaining the historical ratios of pole replacements to pole treatments in the High Corrosion Zone until mid way through next regulatory period, and maintaining the historical ratio of pole replacements to pole treatments in the Low and Moderate Corrosion Zones throughout the next regulatory period.

ETSA Utilities' Revised Proposal is costed in Attachment F.4[166]. The expenditure proposed for the period is $27.2 million (2008 dollars).

ETSA Utilities' expenditure history associated with poles asset replacement is compared with ETSA Utilities' Original Proposal forecast, the AER's Draft Determination, and ETSA Utilities' Revised Proposal forecast in Figure 6.7.

ETSA Utilities considers that the capital expenditure detailed in this Revised Proposal in connection with the replacement of stobie poles is consistent with clause 6.5.7 of the Rules.

The expenditure associated with the replacement of stobie poles is required in order to achieve the capital expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services.

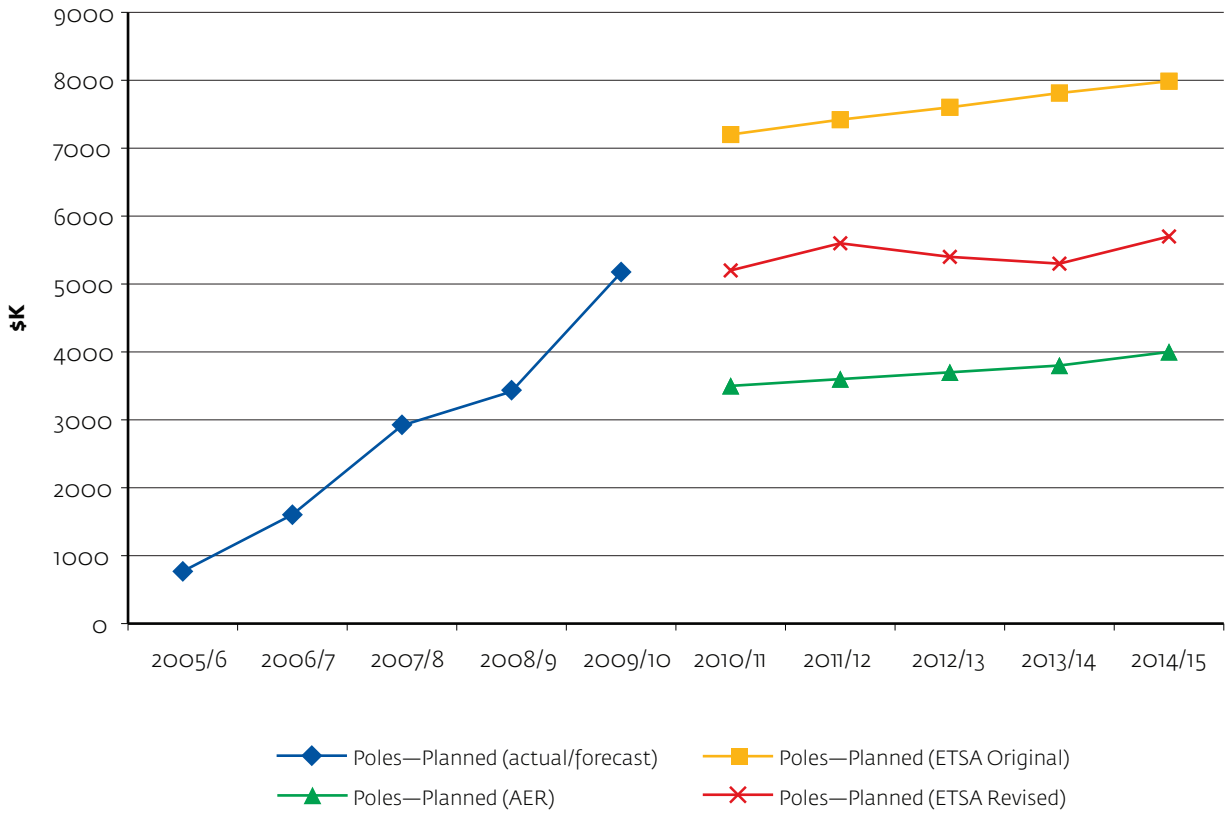
The material that ETSA Utilities has provided to the AER in relation to the modelled failure rates of its poles and ratios achieved from historical condition assessments demonstrates that the forecast capital expenditure reasonably reflects the capital expenditure objectives. In particular, the forecast expenditure reflects the efficient costs of achieving the capital expenditure objectives and the costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capital expenditure objectives.

Revised Proposal

In this Revised Proposal, ETSA Utilities has amended its forecast associated with poles asset replacement, which is based on maintaining the historical ratio of pole replacements to pole treatments in the High Corrosion Zone until mid way through the next regulatory period, and maintaining the historical ratio of pole replacements to pole treatments throughout the next regulatory period in the Low and Moderate Corrosion Zones.

ETSA Utilities' revised forecast results in a total asset replacement positive adjustment of approximately $91m (real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.[167]

Fig 6.7: Poles planned asset replacement expenditure actual (nominal dollars) and forecast (2008 dollars)



166 ETSA Utilities, *Attachment F.4—Capital Expenditure Costing.xls, Poles Worksheet.*

167 Includes all asset replacement adjustments in this Revised Proposal chapter.

6.5.5
Asset replacement expenditure—unplanned lines

ETSA Utilities' Original Proposal

In the Original Proposal, ETSA Utilities proposed expenditure of $71.2 million (2008 dollars)[168] for the regulatory control period associated with the unplanned replacement of power-line assets.

ETSA Utilities' forecast expenditure was determined, on a top-down basis, by an assessment of the failure rate growth and expenditure growth trends, for each class of power-line assets. The assessed failure rate growth and expenditure growth was assumed to continue at the same rate and was utilised to forecast the unplanned lines expenditure for each class of power-line assets.

A planned / unplanned asset replacement trade-off was calculated so that, once planned asset replacement was forecast to stabilise for an asset class, unplanned asset replacement was held constant for that asset class.

PB's Review of ETSA Utilities' Proposal

PB, in their Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, reached the following conclusions:

- That a top-down approach based on the historical expenditure of unplanned lines asset replacement was appropriate.[169]
- ETSA Utilities' derivation of historical trends and application of compounding growth rates into the future is not reasonable and is unlikely to result in forecast expenditures that are prudent and efficient.[170]
- An average of the 2007 and 2008 total unplanned lines expenditure be used as the basis for the forecast of unplanned lines asset replacement expenditure. This was determined to be a suitable basis for the forecast as it was considered to be consistent with ETSA Utilities' business as usual expenditure, and reflected a recent step change in this expenditure.[171]

The AER's Draft Determination

The AER accepted PB's advice that ETSA Utilities had applied unreasonable compounding growth rates which overstated forecast capex. The AER considered that PB's proposed approach of taking the average of 2007 and 2008 expenditure as the basis for the forecast to be a reasonable approach, as it was assessed as consistent with recent business as usual expenditure and reflected the step change in 2007.[172]

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities' Revised Proposal has considered the following:

- ETSA Utilities' historical costs for unplanned lines asset replacement have grown significantly in the current regulatory period (ref Figure 6.8), with increases in each successive year. As ETSA Utilities' network will continue to age and grow within the forecast period, there is no reasonable basis to suggest that these costs will not continue to rise over the forecast period and it is extremely unlikely that the expenditure will remain constant at 2007/08 levels.
- Within PB's and the AER's forecast of Ergon Energy's Asset Replacement expenditure, in an effort to determine business as usual, the continuation of the previous regulatory period's expenditure growth has been applied to the 2009/10 forecast.[173] This is inconsistent with the approach that PB and the AER have utilised to determine ETSA Utilities' unplanned lines asset replacement business as usual levels, where a constant level of 2007/08 expenditure has been assessed as reflective of business as usual. If this approach was utilised, and the average change in expenditure between 2006/07 and 2008/09 was extrapolated from 2008/09, it would result in the 'Business as Usual Trend ' forecast in Figure 6.8. [174]
- This expenditure relates to supply restoration activity which has been capitalised in accordance with ETSA Utilities' accounting practices. ETSA Utilities' Revised Proposal, therefore, has utilised the same approach for forecasting unplanned lines asset replacement as that utilised for the forecast of supply restoration operating expenditure.

The Revised Proposal's forecast unplanned lines asset replacement expenditure is derived from the actual 2008/09 expenditure, escalated by the network growth, de-rated as appropriate for maintenance.[175]

ETSA Utilities' Revised Proposal, the Draft Determination, and the Business as Usual Trend (as defined above) are graphed in Figure 6.8. It is notable that ETSA Utilities' Revised Proposal is conservative compared to the Business as Usual Trend.

168 ETSA Utilities' Original Proposal, *CX001*.

169 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p55.

170 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p55.

171 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p57.

172 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p144.

173 AER, *Queensland Draft Distribution Determination 2010–11 to 2014–15*, p111.

174 ETSA Utilities overspent in comparison to its 2008/09 Asset Replacement capital expenditure forecast.

175 The network growth escalation and maintenance de-rating is documented in this Revised Proposal, chapter 7.

ETSA Utilities' Revised Proposal

ETSA Utilities' Revised Proposal is costed in Attachment F.4.[176] The expenditure proposed for the period is $58.4 million (2008 dollars).

ETSA Utilities considers that the capital expenditure detailed in this Revised Proposal in connection with the unplanned replacement of power-line assets is consistent with clause 6.5.7 of the Rules.

The expenditure associated with the unplanned replacement of power-line assets is required in order to achieve the capital expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services.

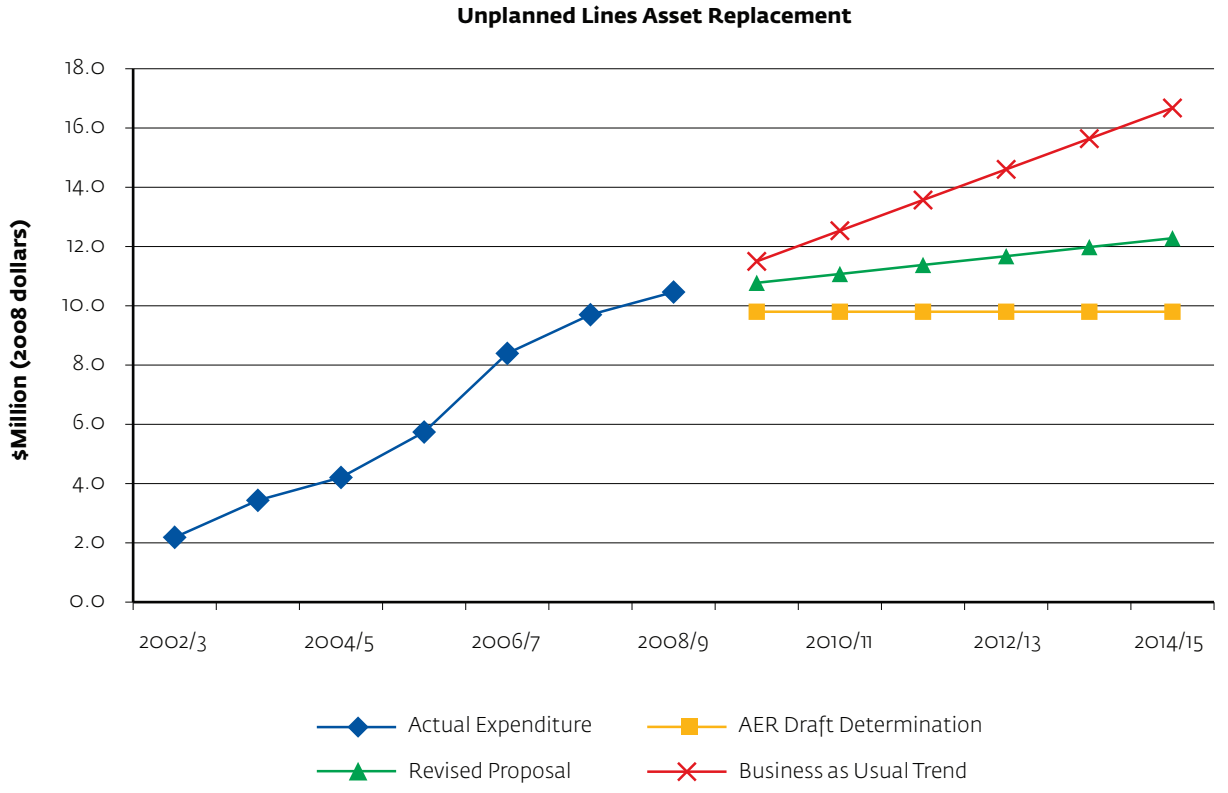
The material that ETSA Utilities has provided to the AER in relation to the forecasting of unplanned lines asset replacement expenditure demonstrates that the forecast capital expenditure reasonably reflects the capital expenditure objectives. In particular, the forecast expenditure reflects the efficient costs of achieving the capital expenditure objectives and the costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capital expenditure objectives.

Revised Proposal

In this Revised Proposal, ETSA Utilities has amended its forecast associated with unplanned lines asset replacement, which is based on the 2008/09 revealed year expenditure escalated for network growth and derated for maintenance.

ETSA Utilities' revised forecast results in a total asset replacement positive adjustment of approximately $91 million (real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.[177]

Fig 6.8 Unplanned lines expenditure—actual, AER Draft Determination, Business as Usual trend and ETSA Utilities' Revised Proposal (2008 dollars)



176 ETSA Utilities, *Attachment F.4—Capital Expenditure Costing.xls, UnplannedLines Worksheet.*

177 Includes all asset replacement adjustments in this Revised Proposal chapter.

6.5.6
Asset replacement expenditure—general

ETSA Utilities' Original Proposal

ETSA Utilities' Original Proposal forecast asset replacement expenditure of $417.1 million (2008 dollars)[178] is in four main asset categories. With the exception of unplanned lines expenditure, which was based on a top-down assessment, the asset replacement forecast expenditure was supported by asset management plans detailing the bottom-up or zero-based calculation of asset replacement requirements for the forecast period.

ETSA Utilities' asset replacement Original Proposal basis and the Asset Management Plans supplied with ETSA Utilities' Original Proposal are summarised in Table 6.5.[179]

PB's Review of ETSA Utilities' Proposal

PB, in their Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, reached the following conclusions:

- PB reviewed 52% of ETSA Utilities' proposed $466.8 million (2010 dollars) and, based on their review, recommended adjustments of $119.4 million (2010 dollars).
- Within the reviewed material, PB noted an inherent reliance on age-based forecasting in addition to ETSA Utilities' existing condition-based forecasts, the use of compounding annual growth rates not supported by historical data, and the limited use of known condition data.[180]
- PB asserted that similar approaches had been adopted across each of the asset categories and therefore concluded that these issues were indicative of a systemic over-estimation of replacement capex.[181]
- On the basis of a perceived systemic over-estimation of replacement capex, PB asserted that the same issues would be identified across the remaining 48% of asset replacement capex which had not been reviewed. In order to test their view, PB conducted a high level review of the Overhead Line Components Asset Management Plan and the Protection and Control Asset Management Plan and identified similar issues to those identified previously.[182]
- A pro-rata reduction was recommended to the 48% of ETSA Utilities' replacement capex proposal that was not subject to specific review. This reduction was calculated as $108.3 million (2010 dollars).[183]

Table 6.5: Asset Replacement—Basis of ETSA Utilities' Original Proposal

Asset Category	Planned/Unplanned	Basis of Forecast	Consultant Review
Powerlines	Planned	11 AMPs	Maunsell
Powerlines	Unplanned	Top-down calculations	N/A
Substations	Planned and unplanned	10 AMPs	Maunsell
Telecommunications	Planned and unplanned	9 AMPs	Maunsell
Meters	Planned and unplanned	1 AMP	Maunsell

178 Based on ETSA Utilities' Original Proposal, *CX001*.

179 Based on ETSA Utilities' Original Proposal, *CX001*.

180 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p70.

181 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p71.

182 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p71.

183 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p71.

The AER's Draft Determination

The AER expressed concern that while PB had been able to identify issues and recommend adjustments to 52% of ETSA Utilities' forecast asset replacement capex, 48% of replacement capex remained as forecast by ETSA Utilities. The AER considered that given the level of adjustment required to the categories subject to the detailed review, a general adjustment to the remaining replacement capex was, under the circumstances, justified. Considering the level of adjustment necessary to the 52% of replacement capex reviewed by PB, the AER considered a proportionate adjustment based on the total adjustments derived from the detailed review to be prudent.[184]

ETSA Utilities' response to the AER's Draft Determination

PB's adjustment to the unreviewed material within ETSA Utilities' Original Proposal was based on the supplementary material as summarised in Table 6.6.

ETSA Utilities does not accept the basis of PB's asset replacement general adjustment for the following reasons:

- Powerlines unplanned replacement was calculated on a top-down basis, and this approach was not utilised elsewhere in ETSA Utilities' asset replacement Original Proposal. This aspect of the asset replacement forecast was, therefore, not systemic throughout the remainder of the forecast.
- It is incorrect to apply the proportion of Powerlines Unplanned Replacement reduction to Substations AMPs, which in the Draft Determination were subject to reductions of planned replacement on an age-related basis, and which were subject to reductions of unplanned replacement on the basis of analysis of historical failures.
- PB's core assumption that similar approaches had been adopted across each of the asset categories is incorrect. The Telecommunications AMPs, none of which were reviewed by PB, were developed mainly on the basis of equipment obsolescence and manufacturer recommendations, and in one AMP, on the basis of maintaining structural integrity of towers in accordance with standards. The Metering AMP, also not reviewed by PB, was generally developed on the basis of compliance with the Electricity Metering Code (South Australia) and the National Electricity Rules.

Table 6.6: Asset Replacement—Basis of PB's general adjustment

Asset Category	Basis of Original Proposal	Original Proposal Value(1) ($2008 m)	Basis of PB's Review	Review Value(2) ($2008 m)	% Expenditure Reviewed
Powerlines Planned	11 AMPs	$160.7	2 AMPs	$66.1	41%
Powerlines Unplanned	Top-down Calculations	$71.2	Top-down Calculations(3)	$71.2	100%
Substations Planned/ Unplanned	10 AMPs	$139.5	2 AMPs	$81.2	58%
Telecommunications Planned/Unplanned	9 AMPs	$29.9	0 AMPs	$0	0%
Meters Planned/ Unplanned	1 AMP	$15.8	0 AMPs	$0	0%

Note:
(1) Based on ETSA Utilities' Original Proposal, *CX001*.
(2) Based on ETSA Utilities' Original Proposal, *CX001*.
(3) ETSA Utilities, *PB.ETS.EM.96 and SI241 EM.96 LinesUnplannedReplacement.xls*.

184 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p145-146.

However, to address the issues raised by the AER in the Draft Determination and without accepting the basis or rationale in the Draft Determination in relation to the adjustment of unreviewed replacement capital expenditure, ETSA Utilities proposes the following adjustment to asset replacement expenditure in the categories not reviewed by PB:

- ETSA Utilities' powerlines planned pro-rata reductions for the material reviewed has been applied to the expenditure associated with the unreviewed powerlines planned asset replacement expenditure.
- ETSA Utilities' substations pro-rata reductions for the material reviewed has been applied to the expenditure associated with the unreviewed substations asset replacement expenditure.
- No reduction has been applied to the Telecommunications and Metering asset replacement expenditure as there is no basis for reduction of this expenditure using PB's and the AER's rationale.

ETSA Utilities' Revised Proposal

ETSA Utilities' Revised Proposal associated with the asset replacement general adjustment is costed in Attachment F.4.[185] The expenditure proposed for the period associated with the material not specifically reviewed by PB is $145.0 million (2008 dollars).

ETSA Utilities considers that the capital expenditure detailed in this Revised Proposal in connection with the forecast asset replacement expenditure in its four main asset categories is consistent with clause 6.5.7 of the Rules.

The expenditure associated with the asset replacement is required in order to achieve the capital expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services.

The material that ETSA Utilities has provided to the AER in relation to the approach taken to forecasting asset replacement demonstrates that the forecast capital expenditure reasonably reflects the capital expenditure objectives. In particular, the forecast expenditure reflects the efficient costs of achieving the capital expenditure objectives and the costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capital expenditure objectives.

Revised Proposal

In this Revised Proposal, ETSA Utilities has amended its forecast associated with the asset replacement general adjustment, which is based on ETSA Utilities' revised methodology for this adjustment.

ETSA Utilities' revised forecast results in a total asset replacement positive adjustment of approximately $91 million (real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.[186]

185 ETSA Utilities, *Attachment F.4–Capital Expenditure Costing.xls, AssetReplGeneralAdjustment Worksheet.*

186 Includes all asset replacement adjustments in this Revised Proposal chapter.

6.5.7 Safety expenditure—substation fencing and security

ETSA Utilities' Original Proposal

In its Original Proposal, ETSA Utilities proposed expenditure of $18.2 million (2008 dollars)[187] for the period associated with the ongoing strategy of increasing substation security. Based on ENA guidelines, key elements of ETSA Utilities' strategy include:

- installation of high security fencing at all metropolitan substations by 2017;
- for all other non-metro high risk substations, installation of appropriate security fencing solutions by 2020;
- installation of high security fencing as standard at high and medium risk sites for new substations and substations undergoing major upgrade; and
- implementation of additional security measures such as CCTV at identified sites.

Application of this strategy requires that 72 metropolitan and 111 non-metropolitan substations require security fence upgrades in the period 2009 to 2020. In the implementation of high security fencing, ETSA Utilities has adopted the combination of Palisade and sheet steel colourbond fencing.

PB's Review of ETSA Utilities' Proposal

PB, in their Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, reached the following conclusions:

- That a targeted approach to improving security at high risk substation sites may be warranted where a site-specific need is identified, supported by a uniformly applied site-specific risk assessment, and where the business is applying an approach driven by security policy and based on a sound business case. PB indicated that these requirements were not demonstrated in their review and concluded that, while addressing the security needs that ETSA Utilities has identified is generally prudent, the efficiency of the scope of ETSA Utilities' proposed security fencing was not demonstrated.[188]
- PB developed a zero-based estimate of ETSA Utilities' substation fencing and security forecast which was based on:[189]
  - installing high security fencing at substations assessed as high risk;
  - installing new chain wire fences to replace the existing fences at substations assessed as low or medium risk where the fence condition is assessed as a high risk;
  - upgrading existing chain wire fences at substations where the fence condition is assessed as a medium risk; and
  - installing CCTV at demonstrated high risk installations following targeted Research and Development to demonstrate the business case.

187 ETSA Utilities' Original Proposal, CX001.

188 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p73-74.

189 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p74.

The AER's Draft Determination

The AER noted that ETSA Utilities' existing fencing meets or exceeds the relevant Australian Standard and its practice of topping fences with three strands of barbed wire is consistent with other electricity companies in Australia and overseas. Despite its fencing meeting the Australian Standards and the widely accepted ENA guideline, ETSA Utilities proposed to adopt a more stringent standard for high security fencing for its substations. The AER noted that ETSA Utilities proposed to assign a high risk to fences at sites which are considered to be low or medium risks. The AER accepted PB's advice that the efficiency of the proposed fencing program had not been demonstrated.[190]

The AER reviewed ETSA Utilities' Original Proposal and PB's advice that the practicalities and effectiveness of the CCTV monitoring had not been evaluated, and considered that the proposed CCTV trial at two sites should be completed and evaluated before a forecast capex allowance is provided.[191]

The AER considered that while ETSA Utilities had demonstrated that its focus on substation security and fencing is prudent, it had not demonstrated the efficiency of the proposed programs. The AER considered that a condition based approach to substation security and fencing be applied and therefore reduced the forecast capex for this category.[192]

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities engaged the legal firm of Johnson Winter & Slattery (JWS) to provide an updated legal opinion on ETSA Utilities' obligations, from a public safety point of view, with regard to substation fencing. The JWS report is included as Attachment F.7 to this Revised Proposal.[193]

JWS agree with PB that ETSA Utilities' priority should be on sites that present the highest risk. However, they do not agree with PB's finding that ETSA Utilities is not justified in upgrading the style of fencing used at low and medium risk sites for the following reasons:

- although a site may appear low risk (for example, no history of break-ins or unauthorised entries), this does not negate the risk that a person will be seriously or fatally injured there in the future;
- as the fencing at higher risk sites is upgraded, there is potential for such low and medium risk sites to become higher risk as, for example, thieves and / or vandals start to select 'easier targets'; and
- as ETSA Utilities begin upgrading fencing at higher risk sites, it becomes harder for ETSA Utilities to justify the reasonableness of retaining less secure fencing at other sites. For example, if an injury or death was to occur at a lower risk site where the fencing had not yet been upgraded, a court may find that the fact that ETSA Utilities has upgraded the fencing at other sites suggests that it was reasonable to expect ETSA Utilities to also have upgraded the fencing at the site in question.

JWS concluded the following with regard to ETSA Utilities' obligations in substation fencing:

- It is reasonable, and prudent, for ETSA Utilities to ensure that its substation fencing complies with the ENA Guidelines. If it does not, there is a foreseeable risk of serious or fatal injury to members of the public and a reasonable risk of ETSA Utilities being held liable in damages for such an injury.
- Therefore, it is prudent for ETSA Utilities to establish a program whereby its existing substation fences are replaced and upgraded over a period of time in order to comply with the ENA Guidelines.
- In such a replacement program, ETSA Utilities should prioritise the replacement of fences at high risk sites.
- Where existing fences at low or medium risk sites require replacement due to the condition of the fences, then it is commercially sensible for ETSA Utilities to upgrade those sites to the higher security fencing, however the higher priority for ETSA Utilities should still be sites that are assessed as being a particularly high risk for the chance of unauthorised entries and injury.

190 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p157-158.

191 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p158.

192 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p158.

193 Attachment F.7: Johnson Winter & Slattery, *AER 2010–2015 Price Reset: Substation Fencing, 7 January 2010.*

In light of JWS' conclusions, ETSA Utilities' Revised Proposal is based on the following:

- *High risk sites*—There are nine sites in the high risk category that are planned for upgrade during the 2010–2015 reset period. The AER's Draft Determination includes a provision to upgrade security at these sites, and this decision is further endorsed by JWS.
- *Joint ElectraNet/ETSA Utilities Shared Sites*—ElectraNet have an approved security fence upgrade plan, with works occurring at 21 shared sites between 2010 and 2014. ETSA Utilities is obliged to contribute to the cost of fence upgrades at these sites.
- *Poor Condition Fences: Medium risk sites*—18 sites have been identified as meeting this criteria. As discussed above, JWS have advised that it is reasonable and prudent for ETSA Utilities to ensure that its substation fencing complies with the ENA Guidelines, and where existing fences at medium risk sites require replacement due to the condition of the fences, then it is commercially sensible for ETSA Utilities to upgrade these sites to the higher security fencing. In accordance with JWS' advice, these 18 sites are planned to be upgraded with high security fencing (combination of Palisade and colourbond, depending on the adjacent land use).
- *Poor Condition Fences: Low risk sites*—23 sites have been identified in this category. JWS have advised that, where existing fencing at low risk sites requires replacement as a result of the fence condition, it may be commercially sensible for ETSA Utilities to upgrade those sites to the higher security fencing. However, JWS considered that, the higher priority for ETSA Utilities should still be sites that are assessed as being particularly high risk. Considering this advice, ETSA Utilities has nominated to replace fences at low risk sites with chainmesh fences. This approach is also broadly in line with the AER's Draft Determination.
- *Security Cameras*—The AER's Draft Determination includes an allowance of $920k for installation of security cameras and $100k for security R&D. ETSA Utilities' Revised Proposal includes the same amount.

ETSA Utilities' Revised Proposal

ETSA Utilities' Revised Proposal is costed in Attachment F.4.[194] The expenditure proposed for the period is $12.3 million (2008 dollars).

ETSA Utilities considers that the capital expenditure detailed in this Revised Proposal in connection with substation fencing and security is consistent with clause 6.5.7 of the Rules.

The expenditure associated with substation fencing and security is required in order to achieve the capital expenditure objectives, in particular, to maintain the reliability, safety and security of the distribution system and to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.

The material that ETSA Utilities has provided to the AER in relation to expenditure in connection with substation fencing and security, including the report from JWS, demonstrates that the forecast capital expenditure reasonably reflects the capital expenditure objectives. In particular, the forecast expenditure reflects the efficient costs of achieving the capital expenditure objectives and the costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capital expenditure objectives.

Revised Proposal

In this Revised Proposal, ETSA Utilities has amended its forecast associated with the substation fencing and security, which is based on recent advice received by ETSA Utilities from its legal advisors and ETSA Utilities' obligations to contribute to ElectraNet's security fence upgrade plan at joint ETSA Utilities / ElectraNet substation sites.

ETSA Utilities' revised forecast results in a positive adjustment of approximately $5 million (real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.

194 ETSA Utilities, *Attachment F.4—Capital Expenditure Costing.xls, SubstationFencing Worksheet.*

6.5.8 Security of supply expenditure—network control

ETSA Utilities' Original Proposal

ETSA Utilities proposed expenditure of $46.0 million (2008 dollars)[195] for the period associated with the replacement or upgrade of network control systems.

ETSA Utilities' forecast scope and estimates were largely based on a report by KEMA. The forecast scope includes:

- replacement of ETSA Utilities' SCADA due to technical obsolescence;
- construction of a larger Network Operations Centre (NOC) to accommodate the increase in resources to support additional field work;
- construction of a back-up NOC to manage the risk of evacuation of the main operations centre; and
- installation of switches at high bush fire risk boundaries to provide for more precise disconnection and reconnection of feeders during high bush fire risk conditions.

PB's review of ETSA Utilities' Proposal

PB, in their Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015, had the following concerns with regard to the Network Control Project:

- That the staffing requirements to deliver the project, as indicated by KEMA, relate to engineering and operational staff. As ETSA Utilities had indicated that the staff costs associated with the NOC should be allocated to forecast opex only, PB recommended reducing the labour component of the network control project by 80 per cent. This resulted in a reduction of $6.9 million (2008 dollars). [196]
- PB considered that while the establishment of a disaster recovery site is prudent and efficient, ETSA Utilities had included IT capex which would have a limited life of two to three years. PB noted that to-date, ETSA Utilities had accepted the risk associated with not having a SCADA equipped disaster recovery centre and it was considered that the additional IT capex for a temporary disaster recovery site was inefficient. Accordingly, PB recommended a reduction of $3 million (2008 dollars).[197]
- KEMA, in its report, included land acquisition costs as part of the costs associated with building the new network operations centre. As the new NOC will be developed on a site owned by ETSA Utilities, PB recommended a reduction of $0.2 million (2008 dollars).[198]

The AER's Draft Determination

The AER noted PB's finding that the bulk of the labour resourcing requirements for the NOC had been included in the capex and opex forecasts. The AER concluded that the double counting associated with the engineering and operational staff should be removed from the capex forecast for the next regulatory control period.[199]

The AER concurred with PB that the IT capex proposed for use over a period of two to three years is inefficient and should be removed from the project.[200]

The AER also concurred with PB that the forecast land acquisition costs associated with the NOC should be removed as the new NOC will be built on land already owned by ETSA Utilities.[201]

ETSA Utilities' response to the AER's Draft Determination

In response to the issues raised by the AER in the Draft Determination, ETSA Utilities consulted KEMA in order to clarify the basis of their estimate, with regard to labour resourcing. KEMA's response, which is included as Attachment F.8,[202] indicated that $1.09 million (2008 dollars) relate to NOC personnel and should therefore be operating expenditure. The remaining $5.8 million (2008 dollars) relates to Field Service personnel and is capital expenditure. Therefore there is no double counting associated with this amount.

In this Revised Proposal ETSA Utilities has incorporated PB's findings that the redundant SCADA System would have a limited life span given the implementation of the proposed SCADA/DMS. This comprises $0.6 million (2008 dollars) of the $3 million (2008 dollars) reduction recommended by PB.

However, ETSA Utilities has not incorporated PB's findings that the following systems have a limited life of two to three years:

- *Protection Settings Sheets Version 4 (PSS4) application:* This is a critical application used for managing and maintaining the reliability of ETSA Utilities' high voltage distribution network protected against electrical faults by fault-sensing devices, called protective relays. PSS4 maintains the protection device settings for more than 16,000 devices. These protection devices automatically trip electricity supply in the event of an electrical fault occurring. These devices protect electricity distribution assets and also provide safety for personnel and the general public.
- *NOC Log:* This is an application utilised by the NOC to record information of SCADA and non-SCADA activity on the network, and is critical for the safe operation of the network. This includes recording information such as the operating state of non-SCADA monitored switches, the progress of switching programs for work on the network, record of switches in an abnormal state, and the time that switches have been operated.

195 ETSA Utilities' Original Proposal, *CX001*.
196 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p84.
197 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p85.
198 PB, *Review of ETSA Utilities Regulatory Proposal for the period July 2010 to June 2015*, p85.
199 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p151.
200 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p151.
201 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p151.
202 Attachment F.8: KEMA, *Clarification of Operational Staff Costs for Network Control Projects, 10 December 2009*.

- *IVR management console:* This is a graphical application used to record, track and manage outage details so that customers are kept up to date on outages and progress in resolving them. It is required to minimise the number of calls logged at the call centre so that information can be sought from customers of new outages or emergency information, such as wires down.
- *TNOC:* Provides essential telecommunications services to the NOC including the mobile radio network, telephony services and communications requirements for the SCADA system. There is currently no disaster recovery site for the TNOC nor replication of critical telecommunication systems. The amount for recommended Disaster Recovery associated with the TNOC was included in the amount discounted by PB as a short life system.

These systems are described in Appendices D, F and G of the KPMG report on the Assessment of Disaster Recovery Options for NOC Operations (included as IT036 with ETSA Utilities' Original Proposal).

ETSA Utilities will require all of the above systems to remain in place for Disaster Recovery purposes once the SCADA has been replaced (ie these systems will not be made redundant by the new SCADA).

ETSA Utilities' Revised Proposal is based on the following:
- Network control project labour resourcing—capital expenditure reduction of $1.09 million (2008 dollars) on the basis that this amount is already costed in operating expenditure.
- Removal of replicated SCADA system on the basis that it is short life—capital expenditure reduction of $0.6 million (2008 dollars).
- Removal of land acquisition costs associated with new NOC—capital expenditure reduction of $0.2 million (2008 dollars).

ETSA Utilities' Revised Proposal

ETSA Utilities Revised Proposal is costed in Attachment F.4.[203] The expenditure proposed for the period is $44.1 million (2008 dollars).

ETSA Utilities considers that the capital expenditure detailed in this Revised Proposal in connection with network control is consistent with clause 6.5.7 of the Rules.

The expenditure associated with network control is required in order to achieve the capital expenditure objectives, in particular, to maintain the quality, reliability and security of supply of standard control services and to maintain the reliability, safety and security of the distribution system.

The material that ETSA Utilities has provided to the AER in relation to expenditure in connection with network control, including the KPMG report and the reports from KEMA, demonstrate that the forecast capital expenditure reasonably reflects the capital expenditure objectives. In particular, the forecast expenditure reflects the efficient costs of achieving the capital expenditure objectives and the costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the capital expenditure objectives.

Revised Proposal

In this Revised Proposal, ETSA Utilities has amended its forecast associated with the network control project, which is based on recent advice from KEMA regarding its resourcing estimates, the removal of the single replicated short life SCADA system in line with the PB's recommendation, and the removal of land acquisition costs associated with the new NOC in line with PB's recommendation.

ETSA Utilities' revised forecast results in a positive adjustment of approximately $8 million (real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.

203 ETSA Utilities, *Attachment F.4—Capital Expenditure Costing.xls, NetworkControl Worksheet*

6.5.9 Expenditure associated with resources for new Negotiating Framework—customer connection

ETSA Utilities' Original Proposal
There was no forecast amount allowed for expenditure associated with resources for a new Negotiating Framework with ETSA Utilities' Original Proposal

ETSA Utilities' Revised Proposal
In this Revised Proposal, ETSA Utilities has included an additional $1.2 million (2008 dollars) per annum of labour within the Customer Connection expenditure. The basis for this amount is detailed within Chapter 2 of ETSA Utilities' Revised Proposal.

Revised Proposal
In this Revised Proposal, ETSA Utilities has amended its forecast associated with the new Negotiating Framework, the basis of which is detailed in Chapter 2 of ETSA Utilities' Revised Proposal.

ETSA Utilities' revised forecast results in a positive adjustment of approximately $5 million (net, real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.

6.5.10 Expenditure associated with equity raising

ETSA Utilities' Original Proposal
In its Original Proposal ETSA Utilities, based on analysis undertaken by the Competition Economists Group (CEG), proposed:

- indirect equity raising costs of 3 percent;
- direct equity raising costs of 4 percent; and
- direct equity raising costs of 1 percent for equity raised through dividend reinvestment plans.

On this basis, ETSA Utilities proposed equity raising costs of $49.5 million, which were determined in accordance with the methodology utilised in the equity raising cash flow model provided by the AER[204] and reflected the values extracted from the Post-Tax Revenue Mode (PTRM). In addition, ETSA Utilities proposed that these costs should be amortised over 22.2 years.

The AER's Draft Determination
In Chapter 7 and Appendix J of the Draft Determination, the AER reviewed equity raising costs and allowed equity raising costs of $9.2 million.[205] In addition, the AER provided a copy of the spreadsheet model which calculated the amount of $9.2 million for equity raising costs, in a file called '30 11 09—ETSA—Attachment L.1 PTRM-ETSA Utilities FINAL—amended—ERC.xls'. Specifically, the AER:

- allowed direct equity raising costs of 3 percent;
- allowed direct equity raising costs of 1 percent for equity raised through dividend reinvestment plans;
- made no allowance for indirect equity raising costs;
- in modelling the equity raising cost allowance, removed the impact of capital contributions on the amount of tax payable in the cash flow analysis; and
- determined a standard life of 52.3 years[206] for amortising equity raising costs in the PTRM, consistent with the weighted average standard asset life for ETSA Utilities and advised that this standard life should also be used for tax purposes.

ETSA Utilities' response to the AER's Draft Determination
ETSA Utilities has responded below to each of the issues and adjustments made by the AER.

Direct equity raising costs
For the purposes of this Revised Proposal, ETSA Utilities notes the AER's Draft Determination to allow 3 percent for direct equity raising costs associated with seasoned equity offerings and 1 percent for equity raised through a dividend reinvestment plan. ETSA Utilities has incorporated these allowances in this Revised Proposal.

204 *Equity raising cashflow sheet (generic).xls, provided by AER via email on 15/5/2009.*
205 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p 165.
206 The Draft Determination states that the AER determined a standard life of 47.8 years for amortising equity raising costs (p 166). The AER advised ETSA Utilities on 15 December 2009 that this figure was incorrect and the standard life for equity raising costs is 52.3 years.

ETSA Utilities notes that a number of aspects of the AER's approach to determining the direct equity raising costs associated with seasoned equity offerings and dividend reinvestment plans, including the sampling of firms and relevant calculations, are not clear from the AER's Draft Determination or other documents provided by the AER to ETSA Utilities. While accepting the AER's Draft Determination in relation to direct equity raising costs, this should not be taken as acceptance by ETSA Utilities of the AER's process for determining these costs.

Indirect equity raising costs

ETSA Utilities notes the AER's Draft Determination to not allow for indirect equity raising costs. This determination has been incorporated into ETSA Utilities' Revised Proposal. However, this should not be construed as an acceptance of the underlying basis or reasoning set out in the AER's Draft Determination. ETSA Utilities remains of the view that the regulatory debate on this matter will continue in future regulatory processes.

Modelling to remove the impact of capital contributions

ETSA Utilities accepts that it is reasonable that capital contributions should not be considered a distributable cash flow, due to their nature, in that these contributions are required to directly fund the asset to which they relate. Acceptance of this reduces, under the AER's methodology, the calculation of required equity raising costs.

However, it is still important to recognise that the benchmark entity will be paying tax on the capital contribution as reflected in the tax allowance provided as part of the PTRM. Recognition of this is important to ensure consistency and the underlying integrity of the equity raising cash flow model.

Accordingly, for the purposes of this Revised Proposal, ETSA Utilities has amended the equity cash flow model to recognise that capital contributions are indeed subject to taxation but at the same time acknowledging the AER's position that capital contribution revenue is not available for distribution. This is further discussed in Attachment F.9 and this Revised Proposal includes equity raising costs of $15.5 million.

Amortising of equity raising costs

The AER has determined the amortisation rate of 52.3 years based on the weighted average standard asset life for ETSA Utilities.[207] ETSA Utilities contends that this is in error. Equity raising costs, quite simply, relate to the funding of proposed capital expenditure and not the opening regulated asset base. This is further discussed in Attachment F.9 and consistent with this, ETSA Utilities has determined an amortisation rate of 20.6 years. Consistent with the Draft Determination, this standard life has been adopted for tax purposes.

Calculation based on smoothed revenue

The AER's methodology utilised in the equity raising cash flow model includes incorporating smoothed revenue in the cash flows, rather than the unsmoothed building block requirement. ETSA Utilities accepts this approach in this Revised Proposal.

However, due to time constraints in the preparation of this response to the AER's Draft Determination, ETSA Utilities has used the unsmoothed building block requirement in the calculation of the equity raising costs. The use of unsmoothed revenue is not expected to have a material impact on the calculation. Nevertheless, it is acknowledged that equity raising costs for the Final Determination will be calculated based on smoothed revenue.

The total amount for equity raising costs is detailed in Table 6.7, and reflects the expenditure allowances in this Revised Proposal.

Revised Proposal

In this Revised Proposal, ETSA Utilities has calculated equity raising costs for standard control services in a manner that recognises capital contributions are subject to taxation and are not available for distribution. An amortisation rate of 20.6 years for standard control services is used in this Revised Proposal for equity raising costs. This Revised Proposal also provides for equity raising costs to be determined on the basis of smoothed revenue.

ETSA Utilities' revised forecast for standard control services results in a positive adjustment of approximately $6.3 million (real, June 2010) to the total forecast capital expenditure proposed by the AER in its Draft Determination.

Table 6.7: ETSA Utilities' Revised Proposal equity raising costs

	2010/11	2011/12	2012/13	2013/14	2014/15
Standard Control Services	15.5	-	-	-	-
Alternative Control Services -Metering Services	0.4	-	-	-	-

Real, June 2010 $M

207 The Draft Determination states that the AER determined a standard life of 47.8 years for amortising equity raising costs (p 166). The AER advised ETSA Utilities on 15 December 2009 that this figure was incorrect and the standard life for equity raising costs is 52.3 years.

6.5.11 Error in Table 7.17 of the Draft Decision

The AER's Draft Determination

ETSA Utilities wishes to note an error in the wording of the AER's Draft Determination. The error has not been carried through to the AER's PTRM, but ETSA Utilities wishes to bring it to the AER's attention.

The AER's Draft Determination included a decision to reclassify certain metering services as alternative control services. Table 7.17 of the Draft Determination reflects this decision by way of a $66.3 million deduction from the capital expenditure allowance. The value of this adjustment was based on the value of ETSA Utilities' metering capital expenditure, as set out in its Original Proposal. The derivation of this value included the application of the cost escalation factors contained in the Original proposal.

However the AER has separately made an adjustment in Table 7.17 to the cost escalators for $107.1 million. This value of $107.1 million includes $5.7 million for the impact of the change in cost escalators on metering capital expenditure.

Consequently, Table 7.17 reflects a double counting of the adjustment to metering capital expenditure for the change in escalation factors. The change is escalation factors has been deducted once as part of the $66.3 million deduction for metering capital expenditure and deducted a second time as part of the $107.1 million adjustment to the cost escalations. As a result of this double counting, the total of the AER's capital expenditure allowance in Table 7.17 of the Draft Determination is thereby understated by $5.7 million due to this double counting.

ETSA Utilities notes that the capital expenditure allowance input into the post-tax revenue model provided by the AER for the Draft Determination does not appear to contain this discrepancy. This issue appears to be limited to Table 7.17 only.

ETSA Utilities' Revised Proposal

The capital expenditure allowance proposed in this Revised Proposal is based on consistently applied real input cost escalation and does not reflect the error noted above. The separation of alternative control services metering capital expenditure from standard control services is discussed in detail in Attachment D.1 to the Revised Proposal.

6.6

INPUT COST ESCALATION

ETSA Utilities has applied real input cost escalation in respect of materials, labour and contract services to capital expenditure forecasts in this Revised Proposal as set out in Table 6.8.

ETSA Utilities has adopted the AER's models for the derivation of real input cost escalators, other than as noted below.

- Materials escalators have been updated to incorporate the latest relevant forecast data. In preparing the updates, SKM applied the AER's forecasting methodologies except for the utilisation of the LME forward contract price for aluminium and copper for the periods 63 months and 123 months. ETSA Utilities has applied the updated SKM forecasts to its materials cost escalation model, which is otherwise unchanged from the model used for ETSA Utilities' Original Proposal.
- Labour escalators have been updated to reflect ETSA Utilities' proposed amendments to the EBA adjustments incorporated in the AER's model for the derivation of labour escalators. ETSA Utilities has otherwise adopted the AER's high-level weighted average labour escalation model and the application of Access Economics' labour cost growth forecasts.
- Construction services escalators have been updated to incorporate the latest CFC real construction cost forecasts. ETSA Utilities has otherwise adopted the AER's high-level weighted average services escalation models and the application of Access Economics' labour cost growth forecasts in respect of construction services and other outsourced services escalators.

A detailed discussion of ETSA Utilities' consideration of the AER's Draft Determination on real input cost escalators, and ETSA Utilities' derivation of real input cost escalators for this Revised Proposal, can be found in Attachment F.10.

Table 6.8: ETSA Utilities' Revised Proposal on real input cost escalators (percent)

	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	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

6.7

ETSA UTILITIES' REVISED PROPOSAL

6.7.1 Standard Control Services

The revised total forecast capital expenditure proposed by ETSA Utilities for the 2010–2015 regulatory control period is detailed in Table 6.9. Note that this table does not incorporate forecast capital expenditure associated with metering services, which are reported discretely in Table 6.10. The forecast capital expenditure associated with metering services is also reported discretely within the detailed model developed by ETSA Utilities for the purpose of forecasting its revised total capital expenditure for the 2010–2015 regulatory control period, provided as Attachment F.1 to this Revised Proposal.

ETSA Utilities has also included, as Attachment F.11, a document of the audit trail from ETSA Utilities' Original Proposal to the AER's Draft Determination to ETSA Utilities' Revised Proposal, and, as Attachment F.12, an updated version of the spreadsheet provided with the Original Proposal as CX001.

The revised total net capital expenditure forecast by ETSA Utilities for the 2010–2015 regulatory control period, excluding metering services, is approximately $1,793 million (real, June 2010).[208] This is approximately 10% higher than the total net capital expenditure allowance of $1,628 million (real, June 2010) proposed by the AER[209] in its Draft Determination.

Compared to ETSA Utilities' Original Proposal, the revised total net capital expenditure forecast by ETSA Utilities for the 2010–2015 regulatory control period, excluding metering services, is approximately 20% lower.[210]

Table 6.9: ETSA Utilities' revised total forecast net capital expenditure for the 2010–2015 regulatory control period (excluding metering services)

	2010/11	2011/12	2012/13	2013/14	2014/15
Network expenditure—demand driven					
Capacity	131.9	176.1	127.5	120.7	115.0
Customer Connection (gross)	153.9	155.6	140.8	146.5	149.0
Customer Contributions	(124.5)	(125.2)	(112.3)	(116.8)	(119.2)
Total demand driven—net	161.4	206.6	156.0	150.5	144.8
Network expenditure—quality, reliability and security of supply					
Asset Replacement	57.6	65.2	63.2	64.7	63.9
Security of Supply	13.8	16.3	16.8	13.9	8.7
Reliability	4.7	4.7	4.6	4.6	4.6
Total quality, reliability and security of supply	76.2	86.2	84.6	83.2	77.2
Network expenditure—safety and environment	25.3	34.3	35.9	35.7	35.0
Non-network expenditure	65.6	57.2	66.6	71.8	79.6
Other—superannuation and equity raising costs	24.0	8.6	8.7	8.8	9.0
Total capital expenditure forecast (net)	352.5	392.9	351.8	350.1	345.6

Real, June 2010 $M

208 Any differences between this amount and the total of Table 6.9 are due to rounding.

209 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 175.

210 Based on expenditure in ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.108.

6.7.2 Alternative Control Services—Metering services

To meet the requirements of the AER's classification of alternative control services, ETSA Utilities was required to separate forecast capital expenditure for alternative control services—metering services from forecast capital expenditure for standard control services. The requirements of the AER's classification of alternative control services are discussed in chapters 2 and 4.

The revised total forecast capital expenditure associated with Alternative Control Services–Metering Services proposed by ETSA Utilities for the 2010–2015 regulatory control period is detailed in Table 6.10 below. The forecast capital expenditure associated with metering services is also reported separately within the detailed model developed by ETSA Utilities for the purpose of forecasting its revised total capital expenditure for the 2010–2015 regulatory control period, provided as Attachment F.1 to this Revised Proposal.

Table 6.10 ETSA Utilities' forecast capital expenditure for alternative control services—metering services in the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15
Alternative control services—Metering services	11.8	12.7	11.3	12.2	12.0

Real, June 2010 $M

7

We do everything in our power to deliver yours

Forecast operating expenditure

7

FORECAST OPERATING EXPENDITURE

In this chapter of the Revised Proposal, ETSA Utilities details its revised operating expenditure forecast for the 2010–2015 regulatory control period. ETSA Utilities has prepared this revised forecast to be consistent with the AER's Draft Decision for South Australia, with the exception of specific deviations which are discussed within the chapter, and which ETSA Utilities considers are required to meet the operating expenditure objectives described within the National Electricity Rules (the Rules).

The specific deviations discussed within the chapter include:

- Network growth scale escalation of operating expenditure activities;
- Escalation of emergency response activities;
- Trade-off for asset replacement;
- Asset age escalation;
- Self insurance;
- Debt raising; and
- Feed-in tariffs.

Additionally, the chapter provides clarification of two matters in relation to which the AER specifically sought clarification from ETSA Utilities within this Revised Proposal, the two matters relate to:

- Superannuation; and
- Internal labour and contract services.

ETSA Utilities has also provided additional information to the AER in support of this revised forecast in compliance with the requirements of the Regulatory Information Notice (RIN) dated 22 April 2009.

7.1

RULE REQUIREMENTS

In accordance with clause 6.12.1 (4) of the Rules, the AER has not accepted the total of the forecast operating expenditure proposed by ETSA Utilities for the 2010–2015 regulatory control period, and has set out its reasons for this decision in its Draft Decision for South Australia (the Draft Determination).

Clause 6.10.3 of the Rules sets out the circumstances under which ETSA Utilities may submit a Revised Proposal, which include the condition that ETSA Utilities may only make revisions to its Original Proposal so as to address matters raised by the AER in its Draft Determination.

7.2

ETSA UTILITIES' ORIGINAL PROPOSAL

In its Original Proposal, ETSA Utilities:

- Proposed total forecast operating expenditure for the 2010–2015 regulatory control period of approximately $1.13 billion [211](real, June 2010);
- Selected the fourth year of the 2005—2010 regulatory control period, being 2008/09, as its efficient base year[212];
- Detailed the process by which it developed its operating expenditure forecast for the 2010–2015 regulatory control period[213]; and
- Demonstrated its efficiency during the 2005—2010 regulatory control period[214], and the efficiency impact of its proposed operating expenditure through to the end of the 2010–2015 regulatory control period[215].

7.3

THE AER'S DRAFT DETERMINATION

The AER reviewed ETSA Utilities' Original Proposal and issued its Draft Determination that:

- ETSA Utilities' actual operating expenditure in the base year has been verified, and that it represents an efficient amount from which to forecast ETSA Utilities' operating expenditure for the 2010–2015 regulatory control period [216];
- ETSA Utilities' forecasting methodology is suitable for forecasting its operating expenditure requirements for the 2010–2015 regulatory control period[217]; and
- ETSA Utilities' forecast operating expenditure for the 2010–2015 regulatory control period is $131m greater than an efficient amount, and that a reduction of 11 percent to the total operating expenditure is proposed [218].

7.4

ETSA UTILITIES' RESPONSE TO THE AER'S DRAFT DETERMINATION

ETSA Utilities has reviewed all of the matters raised by the AER in its Draft Determination including, in particular, where the AER has made adjustments to ETSA Utilities' Original Proposal. ETSA Utilities has prepared this Revised Proposal to be consistent with the Draft Determination, with the exception of the following specific deviations which are discussed in section 7.5.

7.5

DEVIATIONS FROM THE DRAFT DETERMINATION

7.5.1 Network growth scale escalation of operating expenditure activities

ETSA Utilities' Original Proposal

In its Original Proposal, ETSA Utilities forecast the extent to which its electricity distribution network will grow during each year of the 2010–2015 regulatory control period by calculating the percentage increase in its undepreciated regulatory asset base (RAB) for electricity distribution network assets using the following formula:

$$\frac{(\text{Network Extensions} + \text{Upgrades} - \text{Retirements})}{\text{Undepreciated RAB}}$$

ETSA Utilities calculated the operating expenditure associated with this growth by multiplying each category of operating expenditure that is sensitive to the size of the network by one of the growth escalators detailed in Table 7.1.

211 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015*, July 2009, p.150.
212 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015*, July 2009, p.148.
213 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015*, July 2009, p.147.
214 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015*, July 2009, p.146.
215 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015*, July 2009, p.181.
216 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 201.
217 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 193.
218 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. viii.

PB's Review of ETSA Utilities' Original Proposal

PB noted that ETSA Utilities' calculation of network growth *'equates to a 6 year average growth rate of approximately 3.22%, which appears relatively high in the context of the overall cumulative impact'*[219] . Accordingly, PB requested[220] that ETSA Utilities attempt to reconcile its 'top-down' calculation of network growth with a 'bottom-up' calculation based on the forecast growth for specific types of assets during the 2010–2015 regulatory control period.

In response to PB's request, ETSA Utilities supplied a forecast of the growth in four indicators as detailed in Table 7.2, being:

1. Length of powerlines (in kilometres);
2. Number of distribution transformers;
3. Peak demand (in megawatts); and
4. Installed substation capacity (in megavolt amps).

Table 7.1 ETSA Utilities' network growth escalators

	Economy of Scale Factor (%)	2010/11	2011/12	2012/13	2013/14	2014/15
Direct Charges	0	3.20%	3.71%	2.63%	2.24%	2.44%
Maintenance	5	3.04%	3.52%	2.50%	2.13%	2.32%
Operations	75	0.80%	0.93%	0.66%	0.56%	0.61%
Asset Management	90	0.32%	0.37%	0.26%	0.22%	0.24%
Corporate	90	0.32%	0.37%	0.26%	0.22%	0.24%

Table 7.2: Bottom-up forecast provided in response to question PB.ETS.VP.55

	2010/11	2011/12	2012/13	2013/14	2014/15	5 year simple average
Lines (km)	94,570	97,443	100,021	102,806	105,571	
Lines growth (year on year)	**3.02%**	**3.04%**	**2.65%**	**2.78%**	**2.69%**	**2.83%**
Distribution transformers	51,280	52,595	53,939	55,313	56,717	
Distribution transformer growth (year on year)	**2.57%**	**2.56%**	**2.56%**	**2.55%**	**2.54%**	**2.56%**
Peak demand	2,924	3,002	3,126	3,195	3,283	
Peak demand growth (year on year)	**2.45%**	**2.67%**	**4.13%**	**2.21%**	**2.75%**	**2.84%**
Installed substation capacity	4,616	4,737	4,893	5,033	5,153	
Installed substation capacity growth (year on year)	**2.69%**	**2.62%**	**3.29%**	**2.86%**	**2.38%**	**2.77%**

219 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p.139.

220 PB, *Question PB.ETS.VP.55: Size of network growth escalator.*

Of the four indicators detailed in Table 7.2, PB[221] selected three that it considered to be representative of the growth in ETSA Utilities' network over the 2010–2015 regulatory control period. These were: lines growth, distribution transformer growth and installed substation capacity growth. PB calculated the simple average of the growth in these three indicators and recommended that this bottom-up calculation of network growth be substituted for the top-down calculation used by ETSA Utilities in its Original Proposal. The bottom-up calculation of network growth recommended by PB is detailed in Table 7.3, and equates to a five year average growth rate of approximately 2.7%.

The AER's Draft Determination

The AER[222] determined that '*the network growth rate estimated by PB provides a reasonable basis for the over estimation of costs arising from the application of ETSA Utilities' network growth escalator*', and that ETSA Utilities' proposed total operating expenditure should be reduced to account for the adjustment to the network growth escalator. The impact of this adjustment was a reduction of approximately $9.8m (real, June 2010) to ETSA Utilities' proposed operating expenditure for the 2010–2015 regulatory control period.

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities has reviewed the data it supplied to PB (detailed within Table 7.2) and considers that it remains accurate both in the context of the AER's Draft Determination and also in the context of ETSA Utilities' Revised Proposal. As a result, ETSA Utilities does not propose any adjustment to its forecast of the three indicators relied upon by PB in its bottom-up calculation of network growth.

ETSA Utilities has also reviewed the suitability of PB's bottom-up calculation of network growth as a substitute for the top-down calculation adopted by ETSA Utilities in its Original Proposal. As a result of this review, ETSA Utilities considers that PB's bottom-up calculation requires further refinement to take into account the relative weight of the asset classes comprising ETSA Utilities' electricity distribution network, and which underlie the three indicators selected by PB.

By calculating a simple average of the three indicators, PB has applied equal weight to growth in the length of power lines, the number of distribution transformers and substation capacity. However, the asset classes that underpin the growth in these three indicators represent substantially different proportions of ETSA Utilities' total electricity distribution network. Given these circumstances, rather than take a simple average of the growth in each of the three indicators, ETSA Utilities proposes that a weighted average of the growth across the three indicators be used for the bottom-up calculation.

ETSA Utilities has calculated the weightings to be applied to each indicator by reference to the major asset classes that comprise its electricity distribution network. The proportion of the network that each indicator represents is set out in ETSA Utilities' Regulatory Financial Report for the year ended June 2008 and summarised in Table 7.4. The resultant weightings are listed in Table 7.5.

Applying these weightings to the bottom-up forecast of network growth recommended by PB yields a five year average growth rate of approximately 2.8%, as detailed in Table 7.6. Attachment G.2 to this Revised Proposal contains the detailed analysis and calculations supporting the derivation and application of this revised network growth escalator, together with the other scale escalators adopted for this Revised Proposal.

Table 7.3: Bottom-up calculation of network growth recommended by PB

	2010/11	2011/12	2012/13	2013/14	2014/15	5 year simple average
Lines (km)	94,570	97,443	100,021	102,806	105,571	
Lines growth (year on year)	**3.02%**	**3.04%**	**2.65%**	**2.78%**	**2.69%**	**2.83%**
Distribution transformers	51,280	52,595	53,939	55,313	56,717	
Distribution transformer growth (year on year)	**2.57%**	**2.56%**	**2.56%**	**2.55%**	**2.54%**	**2.56%**
Installed substation capacity	4,616	4,737	4,893	5,033	5,153	
Installed substation capacity growth (year on year)	**2.69%**	**2.62%**	**3.29%**	**2.86%**	**2.38%**	**2.77%**
Average growth—bottom up (simple average)	**2.76%**	**2.74%**	**2.83%**	**2.73%**	**2.54%**	**2.72%**

221 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p.139.

222 *AER, Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15, 25 Nov 2009, p. 214.*

Table 7.4: Major asset classes comprising ETSA Utilities' electricity distribution network

	Capital value ($m)	% of total capital value	Relevant growth indicator
Sub-transmission lines	499	7	Lines (km)
Distribution lines	3,281	48	Lines (km)
Substations	1,018	15	Installed substation capacity
Distribution transformers	917	14	Distribution transformers
LVS & meters	855	13	Lines (km)
Communications	73	1	Installed substation capacity
Other	126	2	Lines (km)
TOTAL	**6,769**	**100**	

Table 7.5: Growth indicator weightings

Growth indicator	Weight
Lines (km)	70
Distribution transformers	14
Installed substation capacity	16
TOTAL	**100**

Table 7.6: Bottom-up calculation of network growth using weighted average

	2010/11	2011/12	2012/13	2013/14	2014/15	Weight	5 year weighted average
Lines (km)	94,570	97,443	100,021	102,806	105,571		
Lines growth (year on year)	**3.02%**	**3.04%**	**2.65%**	**2.78%**	**2.69%**	70%	
Distribution transformers	51,280	52,595	53,939	55,313	56,717		
Distribution transformer growth (year on year)	**2.57%**	**2.56%**	**2.56%**	**2.55%**	**2.54%**	14%	
Installed substation capacity	4,616	4,737	4,893	5,033	5,153		
Installed substation capacity growth (year on year)	**2.69%**	**2.62%**	**3.29%**	**2.86%**	**2.38%**	16%	
Average growth—bottom up (weighted average)	**2.90%**	**2.91%**	**2.74%**	**2.76%**	**2.62%**		**2.79%**

For comparative purposes, the adjustment recommended by PB on the basis of a simple average calculation amounted to a reduction of approximately $9.8 million (real, June 2010). The same adjustment based on the weighted average calculation proposed here would have amounted to a reduction of approximately $6.3 million (real, June 2010).

ETSA Utilities considers that the incorporation of a weighted average approach to PB's bottom-up methodology would be consistent with clause 6.5.6 of the Rules. The adjustment is required in order to achieve the operating expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services.

Revised Proposal

This Revised Proposal incorporates the bottom-up calculation of network growth proposed by PB, which has been modified to use the weighted average of the three indicators (lines, distribution transformers and installed substation capacity).

The refinement to the PB methodology involves a positive adjustment of approximately $3.5 million (real, June 2010) to the total forecast operating expenditure proposed by the AER in its Draft Determination.

7.5.2 Escalation of emergency response activities

ETSA Utilities' Original Proposal

Rather than attempt to forecast the workload of each of ETSA Utilities' individual workgroups during the 2010–2015 regulatory control period, ETSA Utilities sought to develop a scale escalation model whereby the high level factors that drive expenditure are quantified and consistently applied across ETSA Utilities' various categories of operating expenditure. ETSA Utilities also applied economy of scale factors to broad groups of activities that are driven by similar factors. In determining the economy of scale factors to apply, ETSA Utilities was guided by the factors accepted by the AER as part of its ElectraNet determination, as well as its own experience and judgement.

Consistent with the approach adopted by ElectraNet[223], Powerlink[224] and TransGrid[225] in their respective revenue proposals, escalation of ETSA Utilities' network maintenance operating expenditure (including emergency response) was calculated by multiplying the controllable operating expenditure associated with these categories of expenditure by the 'maintenance' network growth escalator detailed in Table 7.1, which has an economy of scale factor of 5% applied to it.

223 ElectraNet, *ElectraNet Transmission Network Revenue Proposal—Volume 1, 1 July 2008 to 30 June 2013*, 31 May 2007, p. 83.

224 Powerlink Opex Model, referenced by PB within *Powerlink Revenue Reset: review of capital expenditure, operating and maintenance expenditure and service standards*, December 2006, p. 160.

225 TransGrid, *TransGrid Revenue Proposal, 1 July 2009 to 30 June 2014*, 31 May 2008, p. 87.

PB's review of ETSA Utilities' Original Proposal

PB expressed concern with ETSA Utilities' escalation methodology as it applies to emergency response activities insofar as '*...emergency response not only includes responses to outages due to a variety of issues such as storms, animals contacting live assets and vegetation contacting mains, etc but also from asset failures*'[226] . PB stated that all emergency response operating expenditure should not be escalated for network growth on the basis that:

> '*...new assets are not likely to fail consistently and repeatedly in an unplanned manner...except in the case of run-in failures, which should be covered by manufacturer's warranty.*'[227]

Accordingly, PB requested[228] additional information from ETSA Utilities by which it could determine the proportion of ETSA Utilities' emergency response operating expenditure attributable to equipment failure. In response to PB's request, ETSA Utilities provided a breakdown of its emergency response operating expenditure for the 2008/09 year as detailed in Table 7.7. PB subsequently referenced this information as the basis for a recommendation that the economy of scale factor applied to ETSA Utilities' emergency response operating expenditure should be reduced by 43% to eliminate any expenditure attributable to equipment failure of new assets.

The AER's Draft Determination

The AER accepted PB's recommendation and determined that '*reducing the economies of scale factor for emergency response opex by 43% per cent to 0.54 provides a reasonable estimation of an economy of scale factor*'[229]. The AER requested that ETSA Utilities model the impact of this adjustment on its proposed operating expenditure for the 2010–2015 regulatory control period, and reduced ETSA Utilities' proposed operating expenditure accordingly. The impact of this adjustment was a reduction of approximately $9.5 million (real, June 2010) to ETSA Utilities' proposed operating expenditure for the 2010–2015 regulatory control period.

Table 7.7: Breakdown of emergency response expenditures by cause for the 2008/09 year

Cause	Percentage (%)	Definition
Equipment Failure	43	Result of failed equipment
Third Party	15	Damage to equipment caused by a third party eg. car hit pole
Customer Fault	13	Loss of supply due to a fault in customer's installation
Weather	11	Lightning, wind, vegetation or wind-blown debris
No Cause Found	7	Unknown cause
Asset overload	5	Failure due to overload of assets
Environmental—animals	2	Possums, birds, white ants
ETSA Service Fuse	2	Blown service fuse
Other	2	Miscellaneous other causes
TOTAL	**100%**	

226 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p.142.

227 PB, Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015, p.143.

228 PB, *Questions PB.ETS.VP.48 & 49: Supply restoration cost breakdown.*

229 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.214.

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities has reviewed the statements made by PB, and considers that they do not provide a reasoned basis for its recommendation that ETSA Utilities should adopt a more conservative economy of scale factor for escalation of its emergency response operating expenditure.

ETSA Utilities' escalation of emergency response operating expenditure involves taking the defect ratio that applies to its electricity distribution network assets today, and applying this same ratio to an enlarged network in the future. 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' modelling essentially applies these same failure rates to the enlarged network that will exist during the 2010–2015 regulatory control period. In fact, ETSA Utilities has conservatively applied an economy-of-scale factor of 5% to this defect ratio for the 2010–2015 regulatory control period, recognising that advances in production processes and operating methods may have a marginally favourable impact on failure rates during the 2010 -2015 regulatory control period.

The statements and recommendation made by PB are, for all intents and purposes, identical to the statements and recommendations made by PB and adopted by the AER in relation to its review of Powerlink and TransGrid's initial[230, 231], and Revised[232,233], Proposals. TransGrid ultimately applied to the Australian Competition Tribunal (the Tribunal) for a review of this aspect of the AER's Final Decision. Following this review, the Tribunal concluded that it should:

> *'…set aside the AER's decision in relation to reducing TransGrid's forecast opex and remit the matter back to the AER to make the decision again. Unless it has material to quantify any likely decrease in average defect maintenance costs due to growth assets, the AER should make the decision on the basis that TransGrid's forecast opex is calculated using its opex model with asset growth factors.'*[234]

In reaching this conclusion, the Tribunal[235] noted that PB, the AER and TransGrid had reached 'common ground' in relation to six key issues. The same common ground can be considered to have been reached in relation to ETSA Utilities' Original Proposal, insofar as neither the AER or PB are disputing that:

1. During the 2005—2010 regulatory control period, the average age of ETSA Utilities' assets has increased as its capital expenditure program during this period was insufficient to maintain a constant average age;
2. ETSA Utilities has a growing and maturing asset base;
3. During the 2010–2015 regulatory control period, end of life issues will be more significant for ETSA Utilities than has been the case in the past;
4. ETSA Utilities' average system age will increase, whilst the average age for most asset classes will either remain stable or increase throughout the 2010–2015 regulatory control period;
5. In the absence of a capital expenditure replacement program, the average age of the assets will progressively increase; and
6. If there is no expenditure on new assets over the 2010–2015 regulatory control period, an increasing percentage of ETSA Utilities' assets will move from the random failure zone of the 'bathtub curve' to the wear out zone and average defect maintenance costs would be expected to rise.

As was the case in relation to the proposals put forward by Powerlink and TransGrid, in reviewing ETSA Utilities' Original Proposal, PB and the AER focused on new growth assets and ignored what may occur to ETSA Utilities' network as a whole. The new assets to be installed by ETSA Utilities during the 2010–2015 regulatory control period will not reduce the average age of its network as compared to the 2008/09 base year upon which its defect ratio is based, and therefore ETSA Utilities considers that there is no basis for a more conservative economy of scale factor to be applied to its emergency response operating expenditure.

In relation to the merits review brought by TransGrid, the Tribunal found that the AER was wrong to:

(a) Exclude defect maintenance in respect of new growth assets;
(b) Proceed on a basis that TransGrid would incur zero defect expenditure in respect of new growth assets; and
(c) 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.[236]

230 PB, *Powerlink Revenue Reset: review of capital expenditure, operating and maintenance expenditure and service standards*, Dec 2006, pp. 160–161.

231 PB, *Transgrid Revenue Reset: an independent review prepared for AER*, 12 Nov 2008, pp. 223–224.

232 PB, *Powerlink Revenue Reset: response on selected issues in Powerlink's submission*, Jun 2007, p. 30.

233 PB, *Transgrid Revised Revenue Proposal: an independent review prepared for AER*, 23 April 2009, pp. 69–83.

234 *Application by Energy Australia and Others [2009] ACompT 8 [314].*

235 *Application by Energy Australia and Others [2009] ACompT 8 [299].*

236 *Application by Energy Australia and Others [2009] ACompT 8 [305].*

In the event that the AER determines that the economy of scale factor to be applied to ETSA Utilities' network growth escalator for emergency response should be reduced to account for the expectation that new assets are not likely to fail in an unplanned manner except where such failures would be covered by warranty, the AER will fall into the same error as it did in respect of its treatment of defect maintenance for TransGrid.

ETSA Utilities considers that the escalation of emergency response operating expenditure for network growth assuming a 5% economy of scale factor is consistent with clause 6.5.6 of the Rules. The adjustment reasonably reflects the costs that a prudent operator in ETSA Utilities' circumstances would require to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services.

Revised Proposal

In this Revised Proposal, ETSA Utilities has not incorporated the AER's decision to reduce the economies of scale factor for emergency response operating expenditure by 43%.

ETSA Utilities maintains its Original Proposal that provides for its emergency response operating expenditure to be escalated for network growth assuming a 5% economy of scale factor an approach consistent with:

- *The escalation of the rest of ETSA Utilities' network maintenance-related operating expenditure;*
- *The approaches taken by TransGrid, Powerlink, and ElectraNet; and*
- *The Tribunal's decision in relation to TransGrid's appeal.*

The above adjustment to the AER's Draft Determination involves a positive adjustment of approximately $9.5 million (real, June 2010) to the total forecast operating expenditure proposed by the AER in its Draft Determination.

7.5.3 Trade-off for asset replacement

ETSA Utilities' Original Proposal

In preparing its Original Proposal, ETSA Utilities undertook a detailed evaluation of the capital expenditure and operating expenditure substitution alternatives available to it. In particular, ETSA Utilities investigated the optimal mix of distribution network asset replacement capital expenditure and enhanced condition monitoring operating expenditure by which cost and risk would be balanced. As part of this investigation, ETSA Utilities commissioned specialist engineering consultants SKM to model the impact of ETSA Utilities' proposed capital expenditure on the age profile of ETSA Utilities' assets.

As a result of this investigation, ETSA Utilities determined that the optimal mix of asset replacement and enhanced condition monitoring expenditures would result in an increase in the average age of ETSA Utilities' electricity distribution network assets of approximately three years by the end of the next regulatory control period. SKM estimated that this increase in average asset age would result in additional annual operating expenditure of approximately 1.5—2% per annum during the next regulatory control period. ETSA Utilities conservatively applied this increase only to its forecast emergency response and maintenance operating expenditure and not to its entire network-related operating expenditure, as recommended by SKM.

PB's review of ETSA Utilities' Original Proposal

PB recommended that 'a trade-off be incorporated using a top-down financial ratio methodology'[237] on the basis that:

- ETSA Utilities is projecting a significant increase in replacement capital expenditure across most asset classes; and
- PB is recommending removal of the age escalation applied to maintenance and repair and emergency response operating expenditure.

In place of the detailed evaluation undertaken by ETSA Utilities, PB substituted its own analysis based on the annual ratio of compounding asset replacement expenditure to the current (undepreciated) replacement cost of the asset base. PB then applied a 20% factor to this ratio, which it considered to represent a 'typical' trade-off in maintenance and repair operating expenditure. PB supported its adoption of the 20% factor by stating that it is consistent with its 'experience in working with a number of network operators across Australia'[238].

237 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p.144.

238 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p.144.

The AER's Draft Determination

The AER accepted PB's analysis and determined that the operating expenditure trade off recommended by PB is reasonable[239]. Accordingly, the AER applied a negative adjustment to ETSA Utilities' proposed operating expenditure, totalling approximately $0.3 million over five years.

ETSA Utilities' response to the AER's Draft Determination

The fundamental premise underlying PB's method of analysis is that, if the growth rate of asset replacement expenditure exceeds the rate at which a DNSP's network grows, a larger proportion of that network must be new, and therefore there must be a favourable operating expenditure trade-off. Such analysis, however, fails to take into account the overall average age of the network which, in ETSA Utilities' case, would experience a significant increase—despite the stepped-up asset replacement expenditure.

Hence, PB's analysis leads to the incongruous conclusion that, although ETSA Utilities will be required to operate and maintain an older network during the 2010–2015 regulatory control period, it will also incur less operating costs. ETSA Utilities therefore considers that PB's method of analysis, which it describes as a 'top-down financial ratio methodology[240]', represents an oversimplification of the operating expenditure trade-off relationship and is unsuitable for the application proposed by PB. This view is also shared by SKM[241] who recommend in their Supplementary Report to ETSA Utilities (provided as Attachment G.3) that PB's adjustment be removed, noting that PB's method will only ever result in a decrease in operating expenditure, even when replacement capital expenditure is insufficient to arrest an increase in average network age or proportion of over-age assets.

ETSA Utilities also rejects the appropriateness of the '20% factor' applied by PB to its 'top-down financial ratio methodology' on the basis that it is a gross generalisation, and that PB has provided no evidence to support the appropriateness of this factor, other than to make passing reference in a footnote to its general experience 'working with a number of network operators across Australia'. ETSA Utilities also considers that adoption of such a factor represents a 'double standard' insofar as the prime criticism levied by PB against the detailed analysis undertaken by SKM on ETSA Utilities' behalf is the '...lack of calibration of the SKM age versus operating expenditure characteristics to ETSA Utilities existing asset base and classes'[242]. SKM[243] also observe that PB's approach represents an inconsistency insofar as PB has expressed a preference for bottom-up analysis compared to top-down financial analysis elsewhere in its review of ETSA Utilities' Proposal—notably, in relation to calculation of ETSA Utilities' network growth escalator—and has not demonstrated how this is more accurate than the detailed bottom-up analysis presented by SKM.

In the case of the analysis undertaken by SKM, the specific reasons supporting the application of general findings to ETSA Utilities' asset base were made clear in SKM's report.[244] In contrast, no such justification is provided by PB for a key element of its analysis. ETSA Utilities considers, therefore, that PB's analysis suffers to an even greater extent from the issues attributed by PB to SKM's analysis.

Notwithstanding the two issues described above, ETSA Utilities further considers that the reasons provided by PB as to why ETSA Utilities' method of evaluating the operating expenditure trade-off is unsuitable are inconsequential and invalid reasons to dismiss ETSA Utilities' methodology.

The first reason provided by PB—that ETSA Utilities is increasing its replacement capital expenditure—does not render ETSA Utilities' methodology invalid, nor does it validate PB's methodology. As noted earlier, PB's methodology focuses on this fact but neglects the fact that ETSA Utilities' proposed increase in replacement capital expenditure will be insufficient to stem the increase in the average age of ETSA Utilities' network.

The second reason provided by PB—that it is recommending removal of the age escalation applied to maintenance and repair and emergency response operating expenditure—is a completely unrelated matter, and has no relevance to whether or not ETSA Utilities' evaluation of the operating expenditure trade-off is appropriate. In recommending removal of the age escalation, PB has not disputed the fact that the average age of ETSA Utilities' network will increase during the 2010–2015 regulatory control period. Rather, PB has disputed the magnitude of the increases in operating expenditure associated with this increase in age.

239 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 195.

240 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p.144.

241 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs—Supplementary Report, 8 January 2010*, p. 10.

242 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p.154.

243 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs—Supplementary Report, 8 January 2010*, p.9.

244 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015—Attachment F.3—SKM: Analysis of ETSA Utilities' asset age and condition profile*, July 2009, p.12.

ETSA Utilities considers that the operating expenditure detailed in its Original Proposal, which includes an amount representing the asset replacement capital expenditure trade off, is consistent with clause 6.5.6 of the Rules. The expenditure is required to achieve the operating expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services

Revised Proposal

In this Revised Proposal, ETSA Utilities has not incorporated the AER's decision to reduce ETSA Utilities' proposed maintenance and repair to account for the asset replacement capital expenditure trade off of $0.3 million.

ETSA Utilities maintains its Original Proposal that it will not benefit from a favourable operating expenditure trade-off in relation to asset replacement capital expenditure during the 2010–2015 regulatory control period.

The above adjustment to the AER's Draft Determination involves a positive adjustment of approximately $0.3 million (real, June 2010) to the total forecast operating expenditure proposed by the AER in its Draft Determination.

7.5.4 Asset age escalation

ETSA Utilities' Original Proposal

As noted in section 7.5.3 above, ETSA Utilities engaged SKM to model the impact of its proposed capital expenditure program on the age profile of its assets. As a result of this modelling, SKM determined that the average age of ETSA Utilities' network assets would increase by approximately three years by the end of the next regulatory control period. SKM estimated that this increase in average asset age would result in additional annual operating expenditure of approximately 1.5—2% per annum during the next regulatory control period—an increase which ETSA Utilities conservatively applied to its forecast emergency response and maintenance operating expenditure, and not to its entire network-related operating expenditure, as recommended by SKM.

PB's Review of ETSA Utilities' Original Proposal

PB concluded that the analysis undertaken by SKM and applied by ETSA Utilities was 'generally sound'[245], but that it had *'a number of reservations about the wide-ranging application of the escalators as prepared by SKM and applied by ETSA Utilities'*[246]. The eight 'reservations' specified by PB were that:

1. In PB's view, age versus operating expenditure characteristics can vary significantly within an asset class and across asset classes subject to business strategies and policies.
2. The accuracy of SKM's model is fundamentally dependent on a calibrated age versus operating expenditure characteristic, and that the characteristic applied by SKM was not reconciled or aligned to ensure the age versus operating expenditure curves are appropriate.
3. The inspection, maintenance and repair practices of ETSA Utilities for stobie poles are materially different from the practices adopted by other DNSPs in relation to round wooden or concrete poles . PB considers this difference to be significant as stobie poles comprise 75% of the network by value and exhibit the greatest increase in weighted average age.
4. ETSA Utilities has proposed a variation to increase inspection cycles in high-corrosion zones.
5. ETSA Utilities is planning to move to a condition-based asset management regime, and that this will result in lessening of the operating expenditure/age relationship.
6. The average increase in weighted average age for overhead assets moving from 36 to 44 years is not likely to be a significant factor in increasing operating expenditure as these assets are far from the end of their standard lives.
7. SKM's analysis does not specify an asset failure rate increasing in-line with average asset age, necessitating increase of emergency response operating expenditure directly with the increase in average asset age.
8. ETSA Utilities applied the age escalation proposed by SKM to the entire emergency response operating expenditure, which suggests that all emergency response operating expenditure is caused by asset failure.

In light of these reservations, PB recommended removal of ETSA Utilities' forecast increases in emergency response and maintenance operating expenditure attributed to ageing of ETSA Utilities' electricity distribution network assets[247].

The AER's Draft Determination

The AER accepted PB's recommendation, and determined that ETSA Utilities' proposed increases in maintenance and emergency response operating expenditure due to increasing asset age were not substantiated.[248] Accordingly, the AER applied negative adjustments to ETSA Utilities' proposed operating expenditure, totalling approximately $19.8 million over five years.

245 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p.144.

246 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, pp. 153—154.

247 PB, *Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015*, p.154.

248 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p 219.

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities has carefully reviewed the reservations expressed by PB, and based on its review of PB's report has incorporated a number of adjustments to the application of SKM's modelling to ETSA Utilities' operating expenditure, being reservations numbered 3, 4 and 8. ETSA Utilities considers that the remaining reservations can be addressed through clarification of various aspects of SKM's modelling and its application. ETSA Utilities' response to each of PB's reservations is set out below.

Reservation 1:
In PB's view, age versus operating expenditure characteristics can vary significantly within an asset class and across asset classes subject to business strategies and policies.

ETSA Utilities considers that SKM's analysis, which has involved a significant number of DNSPs operating within Australia, has demonstrated that its age versus operating expenditure characteristics can be generally applied, and that the reservation expressed by PB has not proven to have a significant impact on the results of SKM's modelling. In this regard, ETSA Utilities notes the following statements from SKM's report[249]:

1. The calibrated results from SKM's previous studies fall within a narrow range;
2. The major variance in SKM's previous studies is within the 'substation other' category, which has a low weighting; and
3. In each instance, the escalator assigned to ETSA Utilities is in the bottom 50th percentile of the results from previous studies.

Reservation 2:
The accuracy of SKM's model is fundamentally dependent on a calibrated age versus operating expenditure characteristic, and that the characteristic applied by SKM was not reconciled or aligned to ensure the age versus operating expenditure curves are appropriate.

As noted by SKM[250], a majority of utilities do not have information systems configured to capture operating expenditure costs at a level that can be linked to individual assets, and hence analysed by asset age. This is true for ETSA Utilities. In these circumstances, calibrating age versus operating expenditure characteristics specifically for the ETSA Utilities network would be a very time consuming and expensive undertaking. Faced with this challenge, ETSA Utilities considers that SKM's assessment[251] of the suitability of Powercor's calibrated age versus operating expenditure characteristics—whereby it considered the mix of network assets, the ratio of urban/rural infrastructure, and the overall size of the network—is the best available method by which it can forecast the operating expenditure impact of its ageing network.

ETSA Utilities acknowledges that relying on Powercor's calibrated age versus operating expenditure characteristics does not provide the same precision as would be achieved by developing its own calibrated age versus operating expenditure characteristics. However, ETSA Utilities considers that adoption of Powercor's calibrated age versus operating expenditure characteristics is reasonable and does not introduce an unacceptable level of imprecision in SKM's modelling so as to render it altogether unsuitable. Rather, ETSA Utilities considers that adoption of Powercor's calibrated age versus operating expenditure characteristics enabled SKM to model the impact of asset ageing with greater precision than other available methods, such as taking an average of the results of SKM's previous studies with other DNSPs which, when calibrated, have fallen within a narrow range.

ETSA Utilities' view is also shared by SKM[252], who state that:

1. Although there is some imprecision regarding the age versus operating expenditure characteristics and their application, this is not unreasonable—particularly when compared to other imprecision inherent in forecasting expenditure up to six years in advance; and
2. By rejecting this cost escalation in its entirety, PB and the AER are introducing errors into the accuracy of ETSA Utilities' forecast of the prudent and efficient operating expenditure that will be required to meet the operating expenditure objectives within the Rules—errors which are likely to outweigh any imprecision within ETSA Utilities' forecast, as the approach taken by PB and the AER effectively means that there is no increase in cost with increasing age.

Reservation 3:
The inspection, maintenance and repair practices of ETSA Utilities for Stobie poles is materially different compared with round wooden or concrete poles used by other DNSPs, and this is a significant factor as this asset class comprises 75% of the network by value, and it exhibits the greatest increase in weighted average age.

Although ETSA Utilities' 'Overhead' asset class does represent approximately 75% of the network by value, this asset class includes not only poles, but also conductors, pole fittings, and other overhead assets. Table 7.8 is extracted from SKM's report[253] and details the asset categories comprising this asset class.

249 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015—Attachment F.3—SKM: Analysis of ETSA Utilities' asset age and condition profile*, July 2009, p.12.

250 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015—Attachment F.3—SKM: Analysis of ETSA Utilities' asset age and condition profile*, July 2009, p.10.

251 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015—Attachment F.3—SKM: Analysis of ETSA Utilities' asset age and condition profile*, July 2009, p.12.

252 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs—Supplementary Report*, 8 January 2010, p.11.

253 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010 -2015—Attachment F.3—SKM: Analysis of ETSA Utilities' asset age and condition profile*, July 2009, p.5.

As Table 7.8 indicates, pole infrastructure represents less than 1/5th of the 'Overhead' asset class. As a result, differences in pole infrastructure represent less than 14% of the total network. The other elements of this asset class, particularly overhead fittings and conductors, are identical between the networks, including, for example:

1. Insulators;
2. Cross-arms;
3. Taps; and
4. Tie wires.

Furthermore, additional analysis undertaken by SKM[254] indicates that overhead components other than poles are the dominant factor in the age versus operating expenditure relationship within the Overhead asset class, and that these other components will be the most-affected by ageing during the 2010–2015 regulatory control period.

While ETSA Utilities acknowledges that its pole infrastructure does indeed represent a difference between the two networks, ETSA Utilities deems that this difference is not of a significance that renders the use of Powercor's calibrated age versus operating expenditure characteristics unsuitable. Nonetheless, ETSA Utilities notes PB's comments in relation to the differences in pole infrastructure between ETSA Utilities' and Powercor's networks, as well as PB's reservation regarding the 'wide-ranging application' of SKM's escalators. Accordingly, ETSA Utilities has adjusted its application of SKM's escalator such that it is applied to only 86% of its operating expenditure for network maintenance and repair—effectively removing any age-related escalation attributable to poles, which comprise approximately 14% of the network.

Reservation 4:
ETSA Utilities has proposed a variation to increase inspection cycles in high-corrosion zones.

ETSA Utilities accepts that its variation to increase inspection cycles of poles in high corrosion zones represents part of the additional operating expenditure associated with its age-related escalation. For this reason, and the reasons discussed earlier in relation to Reservation 3, ETSA Utilities has adjusted its application of SKM's escalator such that it is applied to only 86% of its operating expenditure for network maintenance and repair. ETSA Utilities considers that this approach effectively removes any age-related escalation that could be attributable to poles.

Reservation 5:
ETSA Utilities is planning to move to a condition-based asset management regime, and this will have the impact of lessening the operating expenditure/age relationship.

ETSA Utilities notes that PB's statement that ETSA Utilities is planning to move to a condition-based asset management regime is true, however, ETSA Utilities considers that the impact on the operating expenditure/age relationship will not apply during the 2010–2015 regulatory control period. As indicated in ETSA Utilities' Original Proposal[255], its condition monitoring strategies are not yet fully implemented and adequate condition-based information is, as yet, unavailable for many asset types. This is consistent with the detailed description of ETSA Utilities' condition monitoring strategy which was provided as supporting documentation together with ETSA Utilities' Original Proposal[256]. This documentation also explains that ETSA Utilities' move towards condition-based asset management commenced only recently—in June 2007[257].

Table 7.8: Asset categories comprising ETSA Utilities' 'Overhead' asset class

Asset Category	Replacement Cost ($m)	Percentage
Fittings	18,217.8	71.6%
Poles	4,564.9	18.0%
Conductor	2,604.2	10.2%
Other	40.9	0.2%
TOTAL	**$ 25,427.8(1)**	**100%**

Note:
(1) As noted on page 1 of SKM's report, this replacement cost is comprised of the unit cost of replacing individual assets—as would be the case for replacement of aged assets. This replacement costs does not imply the cost of a modern equivalent asset in real terms, which is used in asset valuations employing the Optimised Depreciated Replacement Cost (ODRC) method.

254 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs—Supplementary Report, 8 January 2010*, p. 12.

255 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.120.

256 ETSA Utilities, *OX031: Condition Monitoring and Life Assessment Methodology*, May 2009, p.8.

257 ETSA Utilities, *OX031: Condition Monitoring and Life Assessment Methodology*, May 2009, p.8.

ETSA Utilities' progress in moving towards a condition-based asset management regime was also specifically reviewed by PB during its on-site interviews with ETSA Utilities personnel. During those interviews, ETSA Utilities explained that its key objective during the 2010–2015 regulatory control period is to establish condition monitoring capabilities—teams, processes, and systems—and to commence data collection and analysis activities. ETSA Utilities also explained that it does not anticipate that its condition monitoring regime will have reached a point of maturity—or have adequate capital expenditure provision—to lessen the operating expenditure/age relationship through condition monitoring by 2015.

ETSA Utilities also notes that SKM[258] takes different opinion to that of PB, observing that moving to a condition base asset management approach does not necessarily lead to a lessening of the operating expenditure/age relationship. It is SKM's view that increased inspection and defect maintenance could potentially increase the operating expenditure/age relationship—something that ETSA Utilities considers it will be better-placed to assess for the 2015—2020 regulatory control period.

Reservation 6:
The average increase in weighted average age for overhead assets moving from 36 to 44 years is not likely to be a significant factor in increasing operating expenditure as these assets are far from the end of their standard lives.

ETSA Utilities notes that, during the 2010–2015 regulatory control period, the average age of its overhead assets will remain below their life expectancy. However, ETSA Utilities considers that this factor cannot be considered in isolation. Rather, in assessing the impact of an increase in the average age of an asset class on operating expenditure, it is also necessary to consider the distribution of asset ages within that class.

ETSA Utilities further notes that, if the age of assets in an asset class are clustered around the average and that average is far from the standard life expectancy, a relatively small increase in the average age will not be a significant factor in increasing operating expenditure. However, it is highly unlikely that any asset class built-up over an extended period of time will exhibit such age distributions.

The more common scenario is to have a much wider distribution of asset ages within an asset class, with the age of some assets being well below the average and others well above. This is true of ETSA Utilities' distribution network asset classes.

Under such a scenario, the significance of an increase in the weighted average age of an asset class is not immediately apparent unless further investigation is undertaken to establish whether a sizeable number of assets within an individual asset class will have reached a critical phase in their lifecycle, or alternatively, whether the increase in average age is attributable to ageing of assets within 'safe' phases of their lifecycle.

SKM's modelling for ETSA Utilities' Original Proposal demonstrated that the proportion of its total network assets that will have exceeded 110% of their standard life will more than triple by 2015, and that the number within 100-110% of their standard life will increase by approximately 33%.[259] Such increases are significant, and ETSA Utilities considers that operating, maintaining and repairing a distribution network exhibiting these characteristics represents a major challenge.

Reservation 7:
SKM's analysis does not specify an asset failure rate increasing in-line with average asset age, necessitating increase of emergency response operating expenditure directly with the increase in average asset age.

SKM's method of calculating the relationship between an asset's age and its operating expenditure requirements involves detailed analysis of how various operating expenses vary over an asset's life. As SKM's report[260] indicates, these include operating expenses relating to:

- Asset inspection;
- Routine and corrective maintenance; and
- Emergency response.

Hence, the calibrated operating expenditure-age characteristics within SKM's model incorporate the effects of asset failure rates increasing as an asset ages. ETSA Utilities considers that further 'discounting' or other adjustment of SKM's operating expenditure-age characteristic so that it takes into account an asset's failure rate is neither necessary nor appropriate.

Reservation 8:
ETSA Utilities applied the age escalation proposed by SKM to the entire emergency response operating expenditure, which suggests that all emergency response operating expenditure is caused by asset failure.

In this Revised Proposal ETSA Utilities has adjusted its application of the age escalator, such that its application is limited to only 43% of ETSA Utilities' emergency response operating expenditure. This is consistent with the information provided to PB in response to questions PB.ETS.VP.48 & 49, and reproduced in Table 7.7 within this Revised Proposal.

258 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs—Supplementary Report*, 8 January 2010, p.12.

259 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015—Attachment F.3—SKM: Analysis of ETSA Utilities' asset age and condition profile*, July 2009, p.15.

260 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015—Attachment F.3—SKM: Analysis of ETSA Utilities' asset age and condition profile*, July 2009, p.10.

Summarising comments:
ETSA Utilities has considered in detail PB's review of the modelling undertaken by SKM and its application to ETSA Utilities' forecast operating expenditure. As a result of this review, ETSA Utilities has made two adjustments to the asset age escalation model in this Revised Proposal. These adjustments limit the application of SKM's age escalators to:

1. 86% of its network maintenance and repair operating expenditure, thereby removing any age escalation that could be attributable to poles; and
2. 43% of its emergency response operating expenditure, thereby eliminating any escalation that could be attributable to causes other than equipment failure.

In addition to these two adjustments, ETSA Utilities requested that SKM model the impact of both the AER's proposed adjustments to ETSA Utilities' Original Proposal, as well as ETSA Utilities' Revised Proposal, on the age profile of ETSA Utilities' assets. As a result of this revised modelling, errors were identified in the modelling referenced within ETSA Utilities' Original Proposal—errors which are also discussed in SKM's Supplementary Report[261]. The effect of these errors was to overstate the asset age-related escalators. The incorrect escalators referenced within ETSA Utilities' Original Proposal, together with the correct escalators that should have been referenced in the Original Proposal, are detailed in Table 7.9.

SKM's revised age escalators, modelled according to the AER's proposed adjustments to ETSA Utilities' Original Proposal, as well as ETSA Utilities' Revised Proposal, are detailed in Table 7.10. SKM's supplementary report is also provided as Attachment G.3 to this Revised Proposal.

ETSA Utilities considers that the approach taken in this Revised Proposal to asset age escalation is consistent with clause 6.5.6 of the Rules. The adjustment is required to achieve the operating expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services.

The additional analysis undertaken by SKM demonstrates that the forecast operating expenditure reasonably reflects the efficient costs of achieving the operating expenditure objectives and the costs that a prudent operator in ETSA Utilities' circumstances would require to achieve the operating expenditure objectives.

Revised Proposal
In this Revised Proposal, ETSA Utilities has incorporated the age escalators set out in Table 7.10.

This revision involves a positive adjustment of approximately $6.7 million (real, June 2010) to the total forecast operating expenditure proposed by the AER in its Draft Determination.

Table 7.9: SKM's age escalators, modelled according to ETSA Utilities' Original Proposal

		2009/10	2010/11	2011/12	2012/13	2013/12	2014/15
Incorrect escalators	Annual	1.87%	1.72%	1.40%	1.66%	1.81%	1.97%
	Cumulative	1.87%	3.62%	5.07%	6.82%	8.75%	10.89%
Correct escalators	Annual	1.31%	1.39%	0.80%	1.32%	1.50%	1.56%
	Cumulative	1.31%	2.70%	3.50%	4.80%	6.30%	7.90%

Table 7.10: SKM's age escalators, modelled according to the AER's Draft Determination and ETSA Utilities' Revised Proposal

		2009/10	2010/11	2011/12	2012/13	2013/12	2014/15
AER Draft Determination	Annual	1.31%	1.86%	1.45%	1.97%	1.94%	1.99%
	Cumulative	1.31%	3.17%	4.62%	6.58%	8.52%	10.89%
ETSA Utilities' Revised Proposal	Annual	1.31%	1.65%	1.23%	1.77%	1.76%	1.82%
	Cumulative	1.31%	2.95%	4.18%	5.95%	7.72%	9.54%

261 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs—Supplementary Report*, 8 January 2010, p.4.

7.5.5 Superannuation

ETSA Utilities' Original Proposal

ETSA Utilities' Original Proposal described its legal obligations with regard to making superannuation contributions on behalf of its employees, most of whom are members of the Electricity Industry Superannuation Scheme (EISS). Much of the required increase in contributions above 2008/09 was a result of deteriorating market conditions.

The AER's Draft Determination

The AER accepted the level of payments to be made by ETSA Utilities in respect of defined benefit superannuation contributions, but noted that the AER expects any updated information regarding ETSA Utilities' financial obligations to be reflected in its Revised Proposal.[262]

ETSA Utilities' response to the AER's Draft Determination

As set out in ETSA Utilities' Original Proposal, ETSA Utilities makes defined benefit contributions on behalf of its employees to the EISS. The EISS Actuary, in conjunction with the EISS Board, independently sets the required employer contributions to ensure that the EISS is appropriately funded.

Upon receiving updated advice from the EISS Actuary, the EISS Board has very recently advised that there is no basis to change the long term funding contribution levels for any employer in the EISS. The updated advice received from the EISS Actuary is provided as Attachment G.4 to this Revised Proposal. This includes ETSA Utilities, and takes into consideration the most recent market and fund performance.

The EISS has advised that:

- The losses of the fund for the year ended 30 June 2009 had been appropriately projected and factored into the setting of the contribution levels; and
- In setting long term contribution levels, it had already been assumed that the markets would recover from 1 July 2009.

The risk to ETSA Utilities was that, had the financial markets continued their downward trend post 1 July 2009, employer contributions would have been reset in an upwards direction. As a result of the recent market inquiry, such a reset is not necessary and, accordingly, the employer contributions reflected in the Original Proposal and the AER's Draft Determination continue to apply.

ETSA Utilities considers that the forecast operating expenditure detail in its Original Proposal in relation to superannuation is consistent with clause 6.5.6 of the Rules. This expenditure is required to achieve the operating expenditure objectives, in particular, to meet or manage the expected demand for standard control services and to maintain the quality, reliability and security of supply of standard control services

Revised Proposal

Consistent with the advice of the EISS, ETSA Utilities has maintained its Original Proposal in relation to employer contributions.

7.5.6 Self insurance

ETSA Utilities' Original Proposal

In its Original Proposal, ETSA Utilities included a number of operating costs under the category of self-insurance costs. The self-insurance costs included a base line expenditure forecast of actual costs for the 2008/09 regulatory year. It also included a subsequent adjustment made through independent assessments confirmed by an actuary that supported additional costs that were not reflected in the historical base line numbers. ETSA Utilities proposed costs of $36.5 million (real, June 2010) in its Original Proposal.

The AER's Draft Determination

The AER's Draft Determination rejected most of the costs (allowing only $3.3 million, real, June 2010) in this category notwithstanding that much of the cost associated with self-insurance was deemed acceptable under the review of controllable expenditure. Further, a number of costs were rejected even though they were deemed to be acceptable expenditure if they were included in a different category.

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities is disappointed that the AER has formed its decision and published its Draft Determination without engaging with ETSA Utilities to seek any clarification on many of the matters raised in connection with self-insurance. ETSA Utilities' detailed response on this matter is presented in Attachment G.5 of this Revised Proposal. ETSA Utilities is confident that sufficient supporting material is available to the AER to support an amendment to its Draft Determination.

The self insurance-costs as categorised by ETSA Utilities relate to actual cash outgoings, to be incurred on an ongoing basis, and do not relate to the development of reserves for future events. Examples of self insurance costs include payments for insured events but falling under the deductible levels, repairs to poles damaged by third parties and liability claims. ETSA Utilities considers the AER may not have properly understood how ETSA Utilities used the term self-insurance in its Original Proposal, and ETSA Utilities can assist in consultation with respect to this.

262 AER, *South Australian Draft Distribution Determination 2010–11 to 2014–15*, p.241

With respect to the Draft Determination, ETSA Utilities makes the following comments to assist the AER in reaching an appropriate conclusion based on the material provided:

- There has been no double counting, and the activities that are undertaken by the organisation within the category of self-insurance (as defined by ETSA Utilities) are not otherwise dealt with within other categories[263].
- Cost categories incorporated in self–insurance and referring to damage to poles and wires, and motor vehicle deductibles, for example, are 'business as usual' costs. These costs are not a provision for a loss that may occur, but rather a forecast of expenditures that will occur on a regular basis and which can be forecast with a high degree of certainty. These costs are incurred on a daily basis and could have been charted to categories such as 'pole repair' and 'motor vehicle repair', and have been implicitly allowed as such in other distributor decisions, however ETSA Utilities uses the term self-insurance to assist with its internal risk management policies, which assist in managing costs. The use of the term self-insurance should not in itself be a reason to reduce the expenditure allowance to zero.
- The costs relating to 'claims deductibles' are costs that the organisation needs to incur acting prudently so as to ensure the insurance premium and deductible risk with an insurance company is in combination cost effective. The costs associated with the general and bushfire liability deductible relate to expected outgoings in a year, and do not represent a reserve for future claims. There may be some fluctuations from year to year, relative to other controllable operating expenditure in a network business. ETSA Utilities' claims history in the deductible bands gave rise to payments of more than $8 million in the 10 years to 30 June 2009[264]. ETSA Utilities' experience with the insurance markets demonstrate that external insurance for outgoings associated with the deductible is either not available or it is uneconomical.
- Costs associated with environmental liabilities relate to the outgoings for remediation work and underground repairs, and do not relate to any items that are even remotely associated with illegal or unethical behaviour. They do not relate to reserves for future events, but rather the costs forecast to be incurred based on historical spend.
- The costs associated with motor vehicle claims at the 'below deductible limit' represent payments that could have been categorised as motor vehicle repairs. This category of self-insurance is not a provision for future losses but an expense incurred as a business as usual cost. The use of the term self-insurance should not in itself be a reason to reduce the expenditure allowance to zero.
- Issue of losses—there are no 'loss of profits', 'loss of income' or other such items in the self-insurance cost categories presented.
- A number of self-insurance cost categories were specifically accepted by ESCOSA in the previous regulatory determination, notwithstanding that other electricity network providers may use a different term to describe these costs[265].
- The numerous events in the categories of self-insurance (eg. for property damage and poles and wires there are approximately 400 non-recoverable events each year) means that the pass-through mechanism is not a practical, nor efficient means to recover these costs. Further, as noted above, the number of events and the operating expenditure associated with these events are able to be forecast with a high degree of certainty and it is therefore more appropriate that they are treated as operating expenditure and not as part of the pass through regime.

Compliance with National Electricity Rules

The costs discussed in this response are necessarily incurred in meeting the operating expenditure objectives as discussed in clause 6.5.6(a) of the National Electricity Rules, as set out below. Each of the self-insurance costs claimed by ETSA Utilities:

1. Meet or manage the expected demand for standard control services over the 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; and
4. Maintain the reliability, safety and security of the distribution system through the supply of standard control services.

The costs claimed under the category of self-insurance are ongoing, business as usual outgoings incurred by ETSA Utilities on a basis consistent with other operating expenditures. These expenditures meet the rules listed above and are necessarily incurred in supplying standard control services required by ETSA Utilities' Distribution Licence.

263 For example, costs relating to the activity of repair or reinstatement of poles and wires following a vehicular accident are not covered by the other emergency response categories such as storm damage.

264 Page 26 of Attachment F.5 to Original Proposal, 'AON: Self insurance risk quantification report'.

265 ESCOSA specifically accepted GSL payments (page 100) and bushfire insurance (page 98) in the previous regulatory decision. ESCOSA 2005–2010 Electricity Distribution Price Review. Available at: http://www.escosa.sa.gov.au/library/050405-EDPD_Part_A_StatementofReasons_Final.pdf

Engagement and explanation
ETSA Utilities has not had the opportunity to engage with the AER on the matters raised in Attachment G.5 and is concerned that assumptions and interpretations made by the AER (such as assumed key person insurance, loss of income insurance and costs assumed with illegal activities) are invalid and unsubstantiated and could have been resolved had the matters been discussed before the Draft Determination was released.

ETSA Utilities would appreciate engagement with the AER to ensure that the AER has understood the detail behind the forecasts associated with categories that ETSA Utilities has described as self-insurance. This engagement needs to occur in time for appropriate consideration of the matters set out in the Revised Proposal, before the Final Decision is presented. The total amount for self-insurance cost categories in this Revised Proposal is as detailed within Table 7.11.

Revised Proposal
In this Revised Proposal, ETSA Utilities has incorporated the self insurance costs set out in Table 7.11.

This revision will involve a positive adjustment of approximately $32.7 million (real, June 2010) to the total forecast operating expenditure proposed by the AER in its Draft Determination.

7.5.7 Debt raising

ETSA Utilities' Original Proposal
In its Original Proposal ETSA Utilities, based on analysis undertaken by the Competition Economists Group (CEG), proposed debt raising costs of 12bppa.[266]

The quantum of debt raising costs proposed by ETSA Utilities also included costs connected with the refinancing of debt associated with the completion method.

The total amount for debt raising costs in the Original Proposal was $22.5 million (real, June 2010)[267].

The AER's Draft Determination
In chapter 8 and Appendices I and K of the Draft Determination, the AER determined an allowance of a total of $8.2 million for debt raising costs. This was calculated on the basis of an allowance of 9.1bppa for debt raising costs and no allowance for the costs connected with the refinancing of debt.[268]

ETSA Utilities' response to the AER's Draft Determination
For the purposes of this Revised Proposal, ETSA Utilities:
- accepts the AER's Draft Determination to apply an allowance of 9.1bppa for debt raising costs and has revised its proposal accordingly; and
- does not accept the AER's Draft Determination to make no allowance for the costs of the completion method.

Table 7.11: Self insurance costs ($m June 2010)

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Baseline costs	3.6	3.6	3.6	3.6	3.6	**18.0**
Variation	3.3	3.5	3.6	3.7	3.9	**18.0**
Total costs(1)	6.9	7.1	7.2	7.3	7.5	**36.0**

Note:
(1) This is less than that reflected in the Revenue Proposal due to reduced escalations.

266 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.155.
267 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.155.
268 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, pp 238–239.

Standard debt raising costs

ETSA Utilities commissioned CEG to review the AER's Draft Determination on the calculation of the allowance for standard debt raising costs. The memorandum from CEG is presented at Attachment G.6.

While accepting the AER's Draft Determination to apply an allowance of 9.1bppa for debt raising costs, in the context of recognising that the AER's application of the ACG methodology is likely to continue to be an issue in future regulatory proposals, ETSA Utilities refers the AER to the CEG memorandum.
In particular, ETSA Utilities notes that in deciding upon the sample of bonds from which to determine underwriting costs:

- the rationale provided by the AER for excluding the Fortescue Metals Group (FMG) bonds is not supported by the relevant primary materials, in particular, the underwriting spread of 2.77 percent quoted by CEG (and based on Bloomberg) does not include the costs of issuing equity and debt;
- the rationale given by the AER for excluding Toyota Finance Australia (that the true substance of the bonds reflects an international issuer) in determining underwriting costs could be applied to bonds issued by BHP Billiton and Rio Tinto, which have been included by the AER in its dataset. In this regard the AER's treatment of Toyota, BHP Billiton and Rio Tinto is not consistent; and
- a number of bonds identified by CEG have been excluded by the AER in the calculation of underwriting costs because the AER has not been able to locate them on the Bloomberg service, which appears to reflect an incomplete search of the service by the AER.

ETSA Utilities also notes that in the Draft Determination the AER has adopted a 10 year term for determining the costs of underwriting, consistent with the 10 year term for a benchmark bond.[269] The AER states that to 'allow the maximum collection of data' each bond in the ACG 10 year tenor group (which includes bonds of between eight and twelve years tenor) will be amortised on its particular term to produce a cost estimate.[270] The restriction on the bonds, which are used to estimate underwriting costs, that is only bonds of between eight and 12 years tenor are used, was not part of the ACG methodology and results in a reduction in the amount of information that is used to estimate debt raising costs.
While ETSA Utilities does not comment further on the AER's exclusion of bonds that do not have between eight and twelve years tenor, this should not be taken as ETSA Utilities agreeing with this aspect of the AER's methodology.

Debt raising costs associated with refinancing

ETSA Utilities' Original Proposal included an allowance for debt raising costs associated with the completion method. ETSA Utilities proposed an allowance of 11.2 bppa for these costs.

The AER's consideration of debt raising costs associated with the completion method is provided in confidential Appendix K of the AER's Draft Determination. The AER has raised a number of issues with the incorporation of debt raising costs associated with refinancing in ETSA Utilities' Original Proposal.[271]

ETSA Utilities has engaged PwC to evaluate both the incorporation of an allowance for debt raising costs associated with refinancing and the quantum of any such allowance. It is anticipated that PwC's report will be available to ETSA Utilities in late January 2010, and it will be provided to the AER as soon as possible.

Conclusion

ETSA Utilities has revised its Original Proposal to incorporate the AER's Draft Determination for debt raising costs based on an allowance of 9.1bppa. ETSA Utilities has not revised its Original Proposal with respect to debt raising costs for the completion method.

The total amount for debt raising costs in this Revised Proposal is as follows:

Revised Proposal
In this Revised Proposal, ETSA Utilities has incorporated the debt raising costs set out in Table 7.12.

This revision will involve a positive adjustment of approximately $10.3 million (real, June 2010) to the total forecast operating expenditure proposed by the AER in its Draft Determination.

Table 7.12 Debt Raising Costs (Revised Proposal) ($m)

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Standard Control Services	3.5	3.6	3.72	3.81	3.89	**18.53**
Alternative Control Services	0.10	0.10	0.10	0.11	0.11	**0.52**

269 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, Appendix L, p 530.

270 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, Appendix L, p 530.

271 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, confidential Appendix K, p.576.

7.5.8 Feed-in tariffs

ETSA Utilities' Original Proposal

In its Original Proposal, ETSA Utilities noted that commencement of the *Electricity (Feed-in Scheme-Solar Systems) Amendment Act 2008* makes it a condition of ETSA Utilities' Distribution Network Operator Licence that it will:

- Allow qualifying customers to feed into the distribution network, electricity generated by qualifying generators;
- Provide a credit against the charges payable by the qualifying customers at a rate of $0.44 per kWh for any electricity they feed into the network; and
- Comply with any Ministerial reporting requirements.[272]

ETSA Utilities also indicated that it considered Rule reform to be appropriate to address the issue of recovering the amounts that it and other DNSPs are obliged to pay under jurisdictional feed-in tariff schemes. Accordingly, ETSA Utilities:

- Included within its Original Proposal a forecast of the payments that it expects to make during the 2010–2015 regulatory control period for feed-in tariffs;
- Did not incorporate its forecast of feed-in tariff payments within its total forecast operating expenditure;
- Stated that its total forecast operating expenditure should be considered subject to adjustment for inclusion of its forecast of feed-in tariff payments if a Rule change is not successfully concluded; and
- Proposed that a pass-through event provide for differences between actual expenditures and its forecast of feed-in tariff payments.

On 23 October 2009, ETSA Utilities notified the AER that, given the limited progress of the proposed Rule reform, the AER should incorporate the forecast operating expenditure for feed-in tariffs into ETSA Utilities' total operating expenditure requirements.[273]

The AER's Draft Determination

In the Draft Determination, the AER concluded that:

- The approach taken by ETSA Utilities to determine its forecast allowances for feed-in tariffs for the 2010–2015 regulatory control period was reasonable; and
- The difference between the forecast and actual feed-in tariff payments made in any year should be adjusted through a specific nominated pass through provision.[274]

The AER also noted ETSA Utilities' request that its forecast operating expenditure for feed-in tariffs be included in ETSA Utilities' total operating expenditure requirements.

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities notes the AER's conclusions in its Draft Determination and has incorporated them in this Revised Proposal. However, in preparing its Revised Proposal ETSA Utilities has 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. These forecasts are described in more detail in Chapter 5 of this Revised Proposal.

As a result of this review, ETSA Utilities has determined that it is necessary to revise its forecast operating expenditure associated with feed-in tariff payments for the 2010–2015 regulatory control period. Table 7.13 details ETSA Utilities' original and revised forecasts of the operating expenditure associated with feed-in tariff payments for each year of the 2010–2015 regulatory control period.

ETSA Utilities considers that the proposed amendments will:

- ensure consistency between the sales and demand forecasts set out in the Revised Proposal and its forecast of the payments that it expects to make for feed-in tariffs; and
- 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.

Table 7.13 Forecast operating expenditure associated with feed-in tariff payments

	2010/11	2011/12	2012/13	2013/14	2014/15
Original forecast	5.7	6.9	7.8	8.7	9.7
Revised forecast	7.0	8.7	10.1	11.1	11.7

Real, June 2010 $M

272 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.164.

273 ETSA Utilities, email response to AER, 23 October 2009.

274 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.243.

Revised Proposal
In this Revised Proposal, ETSA Utilities has incorporated the conclusions of the AER with respect to the feed-in-tariffs. ETSA Utilities has also updated its forecast operating expenditure associated with feed-in tariff payments for the 2010–2015 regulatory control period.

Accepting ETSA Utilities' revised forecast will involve a positive adjustment of approximately $9.8 million (real, June 2010) to the total forecast operating expenditure proposed by the AER in its Draft Determination

7.5.9 Internal labour and contract services

ETSA Utilities' Original Proposal

The detailed financial model attached to ETSA Utilities' Original Proposal comprised 63 categories of operating expenditure, each of which included separate forecasts for labour, materials, and services expenditures. The types of expenditures included within each of these forecasts was defined within ETSA Utilities' Original Proposal[275], with further explanation provided within ETSA Utilities' approved Cost Allocation Methodology.

These separate labour, materials, and services forecasts were, in turn, escalated in a consistent manner using forecasts of the labour, material, and services escalation expected to apply to ETSA Utilities during the 2010–2015 regulatory control period. The forecasts relied upon by ETSA Utilities were prepared by economic consultants BIS Shrapnel (for labour cost escalation[276], and services cost escalation[277]), and engineering consultants SKM (for materials cost escalation[278]).

Included among ETSA Utilities' 63 categories of operating expenditure was a single category labelled 'Employee Bonuses', which separately reported the bonuses paid to ETSA Utilities' employees during the efficient 2008/09 base year. This category of operating expenditure comprised only labour expenditure, and was in turn escalated in accordance with the labour cost escalation forecast provided by BIS Shrapnel, as well as the workforce size escalator developed by ETSA Utilities.

The AER's Draft Determination

In its Draft Determination, the AER[279] stated that it does not consider ETSA Utilities' labour cost escalators to be reasonable for the following reasons:

- The forecasts developed by BIS Shrapnel are no longer based on the latest available information;
- The internal labour growth forecast explicitly reflects the impact of ETSA Utilities' own performance and incentive initiatives, including bonus payments (which the AER considers that ETSA Utilities has not demonstrated as efficient); and
- The forecasts do not appear to accurately consider the actual composition of ETSA Utilities' labour resources by type.

The AER also noted[280] that:

> *'...ETSA Utilities' opex modelling includes a separate line item for forecast employee bonus costs, which are escalated by the proposed labour cost growth rates. The AER considers this is inappropriate and appears to result in some double counting of increased internal labour costs arising from ETSA Utilities' internal structural labour incentive arrangements. The AER has been unable to form a view on this issue for this draft decision. The AER will expect ETSA Utilities' revised proposal to provide further information on these proposed bonus costs, and the rationale for applying a real labour cost escalation to those expenditures'.*

For the Draft Determination, the AER substituted its own labour cost escalation rates for the rates developed by BIS Shrapnel which, together with revised services and materials escalators, resulted in a negative adjustment to ETSA Utilities' total proposed operating expenditure of approximately $38 million (real, June 2010).

ETSA Utilities' response to the AER's Draft Determination

The employee bonus costs included in ETSA Utilities' detailed financial model for operating expenditure represent the bonuses paid to ETSA Utilities' employees during the efficient 2008/09 base year. ETSA Utilities has not proposed any variation to these employee bonus amounts in order to provide for any further improvement in performance, or the achievement of any other specific organisational outcomes. ETSA Utilities has simply applied labour cost escalation to the employee bonuses paid during the 2008/09 base year in order to maintain their worth in real terms during the 2010–2015 regulatory control period—effectively maintaining the level of performance achieved during the 2008/09 base year. ETSA Utilities considers that any other increases in bonus payments during the 2010–2015 regulatory control period will only be payable from the benefits arising from outstanding organisational performance, with the Efficiency Benefit Sharing Scheme making adequate provision for ETSA Utilities to facilitate this and share the benefits with customers.

Furthermore, for the purpose of deriving labour escalation factors for the Revised Proposal, other than as noted in Attachment F.10, ETSA Utilities has adopted the weighted average labour input cost escalation methodology preferred by the AER in its Draft Determination. Thus the AER's concerns in relation to the impact of performance and incentive initiatives arising from the use of BIS Shrapnel's labour cost growth forecasts should be alleviated. There is no double-counting of internal labour costs arising from ETSA Utilities' treatment of employee bonuses within its Revised Proposal. Further details of the derivation of ETSA Utilities' revised labour cost escalation are provided within Attachment F.10 to ETSA Utilities' Revised Proposal.

275 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.103.
276 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.103.
277 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.104.
278 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.105.
279 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.209.
280 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.209.

7.6

INPUT COST ESCALATION

ETSA Utilities has applied real input cost escalation in respect of materials, labour and contract services to operating expenditure forecasts in this Revised Proposal as set out in Table 7.14.

ETSA Utilities has adopted the AER's models for the derivation of real input cost escalators, other than as noted below.

- Materials escalators have been updated to incorporate the latest relevant forecast data. In preparing the updates, SKM applied the AER's forecasting methodologies except for the utilisation of the LME forward contract price for aluminium and copper for the periods 63 months and 123 months. ETSA Utilities has applied the updated SKM forecasts to its materials cost escalation model, which is otherwise unchanged from the model used for ETSA Utilities' Original Proposal.
- Labour escalators have been updated to reflect ETSA Utilities' proposed amendments to the EBA adjustments incorporated in the AER's model for the derivation of labour escalators. ETSA Utilities has otherwise adopted the AER's high-level weighted average labour escalation model and the application of Access Economics' labour cost growth forecasts.
- Construction services escalators have been updated to incorporate the latest CFC real construction cost forecasts. ETSA Utilities has otherwise adopted the AER's high-level weighted average services escalation models and the application of Access Economics' labour cost growth forecasts in respect of construction services and other outsourced services escalators.

A detailed discussion of ETSA Utilities' consideration of the AER's draft decision on real input cost escalators, and ETSA Utilities' derivation of real input cost escalators for this Revised Proposal, can be found in Attachment F.10.

7.7

METERING SERVICES

To meet the requirements of the AER's classification of services, ETSA Utilities is required to separately forecast operating expenditure for alternative control services—metering services from its forecast operating expenditure for standard control services. In addition to this separation, forecast operating expenditure for alternative control services—metering services, has been adjusted to reflect the changes to operating costs associated with meeting these requirements. The requirements of the AER's classification of alternative control services are discussed in Chapter 4 of this Revised Proposal. The changes to ETSA Utilities' forecast operating expenditure for alternative control services are described in Attachment D.1.

7.8

REVISED PROPOSAL

The revised total forecast operating expenditure proposed by ETSA Utilities for the 2010–2015 regulatory control period is detailed in Table 7.16. Table 7.16 does not incorporate forecast operating expenditure associated with metering services, which are reported separately in Table 7.15. The forecast operating expenditure associated with metering services is also reported separately within the detailed model developed by ETSA Utilities for the purpose of forecasting its revised total operating expenditure for the 2010–2015 regulatory control period, provided as Attachment G.1 to this Revised Proposal. Attachment G.7 provides an explanation of the input and application of the model.

Table 7.14: ETSA Utilities' revised proposal on real input cost escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	2014–15
Materials	-	-2.60	9.46	3.80	-1.46	-2.44	-2.62
Labour	-	2.30	1.38	0.81	1.26	1.79	1.97
Services—Construction	-	3.15	0.75	0.08	0.72	0.49	-0.09
Services—Other Outsourced	-	1.86	1.05	0.96	1.24	1.76	1.93

Table 7.15: ETSA Utilities' forecast operating expenditure for metering services in the 2010—2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15
Metering services	6.3	6.4	6.6	6.8	7.0

Real, June 2010 $M

The revised total operating expenditure forecast by ETSA Utilities for the 2010–2015 regulatory control period, excluding metering services, is approximately $1,081 million (real, June 2010). This is approximately 4% higher than the total operating expenditure allowance of $1,044 million (real, June 2010) proposed by the AER[281] in its Draft Determination—an allowance which also included ETSA Utilities' alternative control metering services costs. Adjusting the AER's proposed allowance such that it excludes these metering services costs (detailed in Table 7.15) means that ETSA Utilities' revised total operating expenditure forecast is approximately 7% higher than the AER's proposed allowance.

Compared to ETSA Utilities' Original Proposal, the revised total operating expenditure forecast by ETSA Utilities for the 2010–2015 regulatory control period, excluding metering services, is approximately 4% lower than originally forecast[282]—an original forecast which also excluded operating expenditure associated with feed-in tariffs. Adjusting ETSA Utilities' original forecast to include the operating expenditure associated with feed-in tariffs (detailed in Table 7.13), and exclude the operating expenditure associated with metering services (detailed in Table 7.15) means that ETSA Utilities' revised total operating expenditure forecast is approximately 5% lower than its original forecast.

Table 7.16: ETSA Utilities' revised total forecast operating expenditure for the 2010 – 2015 regulatory control period (excluding metering services)

	2010/11	2011/12	2012/13	2013/14	2014/15
Controllable costs					
Network operating costs	28.2	28.6	29.1	29.8	30.6
Network maintenance costs	78.3	80.2	83.2	87.1	89.5
Customer services	21.3	21.8	22.3	22.8	23.5
Allocated costs	48.4	51.8	54.0	58.0	59.0
Total controllable costs	176.2	182.4	188.6	197.7	202.6
Uncontrollable costs					
Superannuation	9.8	9.9	10.0	10.2	10.4
Self insurance	3.0	3.2	3.3	3.5	3.8
Feed-in tariffs	7.0	8.7	10.1	11.1	11.7
Debt raising costs	3.5	3.6	3.7	3.8	3.9
Total uncontrollable costs	23.2	25.3	27.2	28.6	29.8
Total operating expenditure forecast	199.5	207.7	215.8	226.4	232.3

Real, June 2010 $M

281 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.245.

282 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.150.

8

We do everything in our power to deliver yours

Pass through events

8

PASS THROUGH EVENTS

In this chapter of the Revised Proposal, ETSA Utilities responds to the AER's Draft Determination in relation to the nominated pass through events for the 2010–2015 regulatory control period.

ETSA Utilities has prepared this Revised Proposal to be consistent with the Draft Determination, with the exception of specific deviations, including:

- a critical assessment of the criteria the AER has determined it should consider when assessing proposed pass through events;
- a clarification of ETSA Utilities' position in relation to the materiality thresholds for expenditure incurred as a result of a pass through event. In particular and without accepting that a "bright line" threshold is the most appropriate test;
    - ETSA Utilities incorporates the materiality threshold for the AER's specific nominated pass through events of administrative costs; and
    - does not incorporate the threshold of 1 percent of revenue for the AER's general nominated pass throughs, but rather considers that a $5 million threshold is a more reasonable amount when assessing the materiality of an individual pass through event; and
- ETSA Utilities' specific response to a number of the nominated pass through events raised by the AER in its Draft Determination, including (but not limited to) that ETSA Utilities:
    - has not incorporated the AER's rejection of the industry standards event as it considers that there is high probability that such an event will occur over the next regulatory period, with a significant impact on ETSA Utilities' expenditure;
    - has not incorporated the AER's rejection of the retailer failure event as it considers that there is also a high probability that such an event will occur, with ETSA Utilities being exposed to considerable financial risk;
    - has not incorporated the AER's rejection of the interim period event for the reasons outlined in its Original Proposal and on the basis that allowing such an event is within the scope of the AER's decision making powers; and
    - has incorporated the AER's rejection of the extraordinary event pass through proposed by ETSA Utilities, but with the consequence that additional pass through events have been proposed (eg Retailer of Last Resort (ROLR) obligation event), which would have been captured by the extraordinary event pass through had that pass through been accepted by the AER.

8.1

RULE REQUIREMENTS

Clause S6.1.3(2) of the Rules provides that a building block proposal must contain a proposed pass through clause with a proposal as to the events that should be defined as pass through events.

The definition of a pass through event is set out in Chapter 10 of the Rules and, relevantly, includes any of the following events:

a) a regulatory change event;
b) a service standard event;
c) a tax change event; and
d) a terrorism event.

In addition to those listed above, an event nominated in a distribution determination as a pass through event is a pass through event for the purposes of the determination. The AER's determination as to whether additional pass through events should be allowed in a determination is governed by the National Electricity Objective in section 7 of the Law and the revenue and pricing principles in section 7A. Specifically, the AER must have regard to the principle that network service providers should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services.

Clause 6.12.1(14) of the Rules provides that a decision on the additional pass through events that are to apply for the regulatory control period is a constituent decision of a distribution determination.

8.2

ETSA UTILITIES' ORIGINAL PROPOSAL

In chapter 8 of its Original Proposal, ETSA Utilities:

- nominated a number of pass through events for the regulatory control period 2010–2015[283];
- discussed the role of pass through events in the context of incentive regulation and the risks to the distribution business associated with events outside of its control; and
- made a submission in relation to the appropriate materiality threshold for a pass through event. In that submission, ETSA Utilities proposed that:
  - a 'bright line' materiality threshold should not be adopted; and
  - the preferable threshold is that the relevant event has had a material impact on the costs incurred by ETSA Utilities in providing the relevant services.

283 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.186

8.3

THE AER'S DRAFT DETERMINATION

In the Draft Determination, the AER considered that nominated pass through events should be divided into two categories:[284]

- specific nominated pass through events (highly likely to occur); and
- general nominated pass through events (unexpected).

The AER determined that it would accept the following specific nominated pass through events for ETSA Utilities for the 2010–2015 regulatory control period:[285]

- a smart meter event;
- a CPRS event;
- a feed-in tariff event; and
- a native title event.

The AER rejected ETSA Utilities' proposal for the following nominated pass through events:

- an extraordinary event;
- a connection point project event;
- an industry standards change event;
- a retailer failure event; and
- an interim period event.

While the AER considered that these events should not be nominated as specific nominated pass through events, the AER noted that if the events were to occur in the next regulatory control period, ETSA Utilities may apply to the AER for a pass through under the general nominated pass through provisions and the AER would assess any such application with reference to its Draft Determination and the Rules.[286]

The AER nominated the following circumstances in which a general nominated pass through event may occur for ETSA Utilities during the 2010–2015 regulatory control period:[287]

- an uncontrollable and unexpected event occurs, the effect of which could not have been prevented or mitigated by prudent operation risk management;
- the change in costs of providing distribution services as a result of the event is material; and
- the event does not fall into any of the definitions of other accepted categories of events such as already provided for in the Rules and in the AER's Draft Determination.

284 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, pp. 397–398.
285 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, pp. 407–408.
286 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 406.
287 AER, Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15, 25 Nov 2009, pp. 407–408.

The AER also considered in its Draft Determination that a materiality threshold should generally apply to pass through events. In particular, the AER determined that:

- for general nominated events, the costs associated with the event would exceed one percent 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[288]; and
- for specific nominated events, the costs associated with the event would exceed the administrative costs of assessing an application relating to those events[289].

In so doing, the AER rejected ETSA Utilities' proposal that the determination of the materiality should not be determined by reference to a 'bright line' threshold but rather be a subjective consideration of whether the event has a material impact on the costs incurred by the DNSP.[290]

8.4

ETSA UTILITIES' RESPONSE TO THE AER'S DRAFT DETERMINATION

ETSA Utilities has reviewed all of the matters raised by the AER in its Draft Determination including, in particular, where the AER has not accepted ETSA Utilities' proposed pass through provisions.

ETSA Utilities has prepared this Revised Proposal to be consistent with the Draft Determination, with the exception of the following specific deviations which are discussed below.

8.5

DEVIATIONS FROM THE DRAFT DETERMINATION

AER's criteria for the assessment of proposed pass through event

In its Draft Determination, the AER set out the criteria it considers when assessing proposed pass through events. In particular, the AER noted the pricing principles in section 7A(2) of the Law and the structure of the incentive regime as providing indirect guidance to the AER in deciding upon which events should be accepted as nominated pass through events. The AER noted that while a pass through of costs may provide an opportunity for a regulated DNSP to recover at least its efficient costs, its application is limited as a cost pass through and has the potential to undermine the incentive for the business to effectively manage risk.[291]

In addition to the guiding principles of the NEL, the AER also identified eight assessment criteria which comprised the factors it had regard to when it determined whether an event should be nominated as a pass through event for the ACT and NSW DNSP's 2009–10 to 2014–15 distribution determinations.[292] Amongst the list of eight factors the AER had regard to was that:

> *'despite the event being foreseeable, the timing and/or cost impact of the event could not be reasonably forecast by the DNSP at the time of submitting its regulatory proposal'.*

While for the purposes of the ACT and NSW DNSP's determinations the AER considered an event to be 'foreseeable' if it was expected to occur, the AER in its Draft Determination for ETSA Utilities noted that it had further reflected on the nature of foreseeability and revised its position. The AER considered that as it was possible that the general meaning of 'foreseeability' may capture a broader range of events than those 'expected' to occur, the factor was amended for the purposes of the Draft Determination for ETSA Utilities. The amended criterion which the AER was now to have regard to was that:

> *'despite the event being highly likely to occur, the timing and/or cost impact of the event could not be reasonably forecast by the DNSP at the time of submitting its regulatory proposal'.*

The AER identified this factor and the factor relating to a DNSP's degree of control over an event as the most significant factors it should have regard to when it determines whether an event should be nominated as a pass through.[293]

The two categories that the AER define for pass through events (specific events that are "highly likely" to occur, and general events that are "unexpected") means that the only events that the AER will accept as being nominated in a distribution determination are events that fall at two ends of a spectrum of possibility, being: "highly likely" and "unexpected". ETSA Utilities considers that this restriction on events that may be nominated as pass through events is without basis and is inconsistent with the Law and the Rules.

ETSA Utilities' response to AER's criteria for the of proposed pass through events

ETSA Utilities does not consider that the AER has in its Draft Determination sufficiently explained its reasons for amending its criteria for assessing proposed pass through events such that an allowable specific nominated pass through event must be "highly likely to occur" rather than "foreseeable". While the AER has noted that it considers the concept of foreseeability may be capable of being construed too broadly, it has not given any reasons as to why a pass through event must be assessed as highly likely to occur before being accepted as a pass through event for the purposes of ETSA Utilities' determination.

288 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.400.

289 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.401.

290 *ETSA Utilities, ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.192

291 AER, Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15, 25 Nov 2009, p.395.

292 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.396.

293 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.397.

While the AER's approach to the discussion of this issue makes is difficult for ETSA Utilities to respond in any detailed way, ETSA Utilities submits that an assessment of the validity of a pass through event on the basis it is highly likely to occur is both an inconsistent application of the specific pass through provisions under the Rules, and is unreasonable.

In amending the assessment factor to "highly likely" from "foreseeable", the AER has increased the threshold for the determination of a specific nominated pass through event to an unreasonable and unworkable level. By importing such a high threshold for assessment the AER has:

- excluded from either of the nominated pass through categories (specific and general) those events, which may be expected to occur in the next regulatory period but which are not highly likely to occur in that period (e.g. service standards event); and
- driven a number of identifiable events unnecessarily into the general nominated events category, which would subject them to the AER's higher materiality threshold for this category (see section [8.6] below).

The threshold of "highly likely" for specific nominated pass through events is inconsistent with the intention behind the pass through provisions in the Rules. This is also the case in relation to the threshold of "unexpected" for the general nominated pass through events.

The application of the AER's criteria means the AER will only accept as being nominated in a distribution determination those events that fall at two ends of a spectrum of possibility, being: "highly likely" and "unexpected". In adopting this position, the AER has predetermined that any event falling between these two points will not be able to be nominated in a distribution determination. In the Draft Determination the AER does not set out the basis and rationale for this determination.

ETSA Utilities considers that the AER's position is unreasonable and does not have any foundation in the Rules or the Law. Under the Rules it is open to a DNSP to specify any event as a pass through event. It is then for the AER to determine, consistent with the relevant provision of the Rules and the Law, whether that event should properly be nominated in the distribution determination as a pass through event. In so doing, the AER's discretion is to be guided by sections 7 and 7A of the Law. There is nothing in these provisions which would preclude the inclusion of an event because, in the AER's view, it falls somewhere between being "highly likely" and "unexpected". The AER excludes the retailer failure event, industry standards change event, and connection point project event including on the basis that these events are not "highly likely".

The exclusion of costs associated with events that may fall between "highly likely" and "unexpected" is inconsistent with the principle that a DNSP be provided with a reasonable opportunity to recover at least its efficient costs as contemplated by section 7A(2) of the Law.

The exclusion of costs associated with these events is also inconsistent with the policy intent of the pass through provisions. The inclusion of the pass through provisions in the Rules reflects the policy considerations of the Ministerial Council on Energy and its advisory standing committee of officials (MCE SCO). The policy intent of the MCE SCO was that costs which were uncertain and outside the control of the DNSP could be nominated as additional pass through events.[294] That is, the intent was not that only events that were "highly likely" or "unexpected" would be able to be nominated as pass through events. Rather, the intent was that any event for which costs were uncertain and outside the control of the DNSP could be nominated.

For example, in commenting on the differences between the transmission and distribution rules with respect to contingent projects, the MCE SCO noted that there was no contingent project regime in the distribution rules and that "uncertain" distribution projects may be accommodated by pass through.[295] Similarly, in responding to stakeholder comments on the exposure draft of the distribution Rules, the MCE SCO noted that "[U]ncertainty around capex projects can be dealt with via the pass through provisions to the extent that the DNSP can demonstrate that the event is outside its control"[296].

As to the kinds of things that might reasonably qualify as nominated pass through events, the AER should also be guided by the pass through events that are specifically provided for in the Rules.

In particular, the Rules specify a "terrorism event" as a defined pass through event. While the occurrence of a terrorism event during the next regulatory control period may be foreseeable, in the sense of it occurring as a matter of possibility, it may not be considered to be either "highly likely" or "unexpected", however it is included in the Rules as a pass through event. Accordingly, using the AER's own assessment criteria as currently determined in its Draft Determination, a terrorism event may not be determined to be eligible as a specific pass through event. This should provide a clear indication to the AER that its assessment criteria are inconsistent with the Rules and the intent of the pass through provisions. What is relevant is whether the costs associated with a nominated pass through event are "uncertain".

294 Standing Committee of Officials of the Ministerial Council on Energy, *Changes to the NER to Establish a National Regulatory Framework for the Economic Regulation of Electricity Distribution: Explanatory Material*, April 2007, p 53; Standing Committee of Officials of the Ministerial Council on Energy, SCO Response to Draft NER, August 2007, Table 1: SCO response to stakeholder comments on the Exposure Draft of the NER for distribution revenue and pricing (Chapter 6) pp 32 and 33.

295 Standing Committee of Officials of the Ministerial Council on Energy, *Changes to the NER to Establish a National Regulatory Framework for the Economic Regulation of Electricity Distribution: Explanatory Material*, April 2007, p 53.

296 Standing Committee of Officials of the Ministerial Council on Energy, *SCO Response to Draft NER*, August 2007, Table 1, pp 29 and 33.

A DNSP should be able to nominate in its distribution determination, pass through events which have uncertain costs. Whether such events are "highly likely" or "expected" is irrelevant. ETSA Utilities also notes that the inclusion of a particular nominated pass through event does not automatically result in costs being passed through – once an event has occurred, the AER then determines the appropriate pass through amount (if any) consistent with the national electricity objective.[297]

In the Draft Determination the AER does not provide any reason as to why the pass through events as defined in ETSA Utilities' Original Proposal are inconsistent with the provisions of the Rules or the Law, as a consequence of those events not being highly likely to occur. The AER also does not identify any reason why the extraordinary event as defined in the Original Proposal is inconsistent with the Rules or the Law. The AER should amend ETSA Utilities' regulatory proposal only to the extent necessary to enable it to be approved in accordance with the Rules as opposed to fitting the AER's preferred framework which it has constructed without legal basis over the nominated pass through events.

8.6

CLARIFICATION OF MATERIALITY THRESHOLDS

As outlined above, ETSA Utilities notes that the AER has determined that materiality should be determined by reference to a 'bright line' threshold of:

- 1 percent of annual forecast revenue for general nominated pass through events; and
- the administrative costs of assessing an application for specific nominated pass through events.

ETSA Utilities maintains the position in its Original Proposal that the determination of the materiality threshold should not be a 'bright line' threshold, but instead be determined by reference to whether the event has had a material impact on the costs incurred by ETSA Utilities in providing the relevant services, which would not have eventuated but for the occurrence of the event.[298]

ETSA Utilities' response to AER's materiality threshold for general nominated pass through events

ETSA Utilities submits that the AER's threshold of 1 percent annual forecast revenue is far too onerous a threshold for determining the materiality of general nominated pass through events (particularly capital expenditure where the AER's definition of incurred costs are the return on capital and depreciation of capital). For an event incurring soley captial expenditure to meet this threshold, ETSA Utilities has calculated that the event would need to be responsible for an increase in ETSA Utilities' capital expenditure of $70 million, which is approximately 20 percent of ETSA Utilities' average annual forecast capital expenditure.[299] ETSA Utilities submits that such an increase in capital expenditure would not be able to be funded from cash from operations.

The AER's definition of materiality is also problematic in relation to costs that may be incurred for a general nominated pass through event, but which traverse more than one regulatory year. Under the AER's current materiality approach for a general nominated pass through, if expenditure for costs associated with such an event were incurred over a period spanning, for instance, two regulatory years, that event and therefore those costs would not appear to be recoverable if the disaggregated costs are less than the 1 percent threshold of revenue for each of those regulatory years. That is, despite the total expenditure incurred as a result of the event satisfying the AER's 1 percent threshold for a general nominated pass through event, the mere fact that the costs were incurred across regulatory years rather than within one regulatory year would disentitle ETSA Utilities to the recovery of those costs.

In its price determination for ETSA Utilities for the period 2005–2010, ESCoSA considered that a subjective test was more appropriate than establishing a bright-line test.[300] Accordingly, under ETSA Utilities' current arrangements, ESCoSA assesses the materiality of any pass through amount with reference to the merits of each individual case. In making a decision in relation to a pass through event, ESCoSA must take into consideration any previous relevant pass through event in the same category.[301] Accordingly, under the current arrangements, ESCoSA is obliged to effectively aggregate the costs associated with multiple events in one pass through category. This approach mitigates the risk that the costs associated with any one event seen in isolation would be considered by the regulator to be immaterial despite contributing, along with other events, to a significant impact on ETSA Utilities' revenue.

297 Standing Committee of Officials of the Ministerial Council on Energy, *SCO Response to Draft NER*, August 2007, Table 1, p 87.

298 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.192

299 For example, if ETSA Utilities' five year revenue requirement is in the order of $3,796.5 million, this gives an average revenue of $759.3 million per annum, or a 1% materiality threshold of $7.59 million. Using a Nominal Vanilla WACC of 10.02% and an asset age of 50 years, a capital expenditure of $70.58 million will have a revenue impact of $7.59M.

300 ESCoSA, 2005–2010 Electricity Distribution Price Determination – Part A Statement of Reasons, April 2005, p. 203 [13.7].

301 ESCoSA, 2005–2010 Electricity Distribution Price Determination – Part B Price Determination, April 2005, p. 21 [4.5.2(e)].

The AER does not set out the basis and rationale for the determination on the materiality threshold – either in relation to the quantum or why the threshold is determined by reference to the years of the regulatory control period in which the costs are incurred. The materiality threshold is not supported by reference to the Rules or the Law. The appropriate threshold should be determined by reference to the requirements of the Law in section 7 and 7A, in particular, that a DNSP should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services and complying with a regulatory obligation or requirement. A threshold developed by reference to this guiding principle would appear to address the AER's concern that DNSPs may seek to pass through immaterial costs that could be accommodated in the normal course of operational activities and budget management. ETSA Utilities refers to, and relies on, its Original Proposal in relation to the issue of any materiality threshold.

In addition, the AER's current approach of limiting the specific nominated pass through events only to those which are "highly likely" to occur will result in a greater number of events being categorised as a general nominated pass through event. As a result, the likelihood of the occurrence of more than one event within a single regulatory year will increase. As discussed above, the materiality threshold for a general nominated pass through event differs in quantum from that of a specific nominated pass through event, with each general nominated pass through event needing to exceed a threshold of 1 percent of revenue. Accordingly, in any given regulatory year, ETSA Utilities may be subject to a number of small general nominated pass through events which individually do not exceed the general nominated pass through threshold but, in aggregate, impact upon the business in excess of 1 percent of revenue for that regulatory year. The AER's current approach disentitles ETSA Utilities to recovery of those costs, despite the significant impact they may have on its revenue, and despite the AER's own view that an impact on revenue of 1 percent is material.

ETSA Utilities submits that these perverse outcomes are an inherent consequence of the AER's current approach and demonstrates a need for the AER to modify the materiality test in line with ETSA Utilities' Original Proposal, which contemplated a subjective consideration of whether the occurrence of the event has had a material impact on the costs incurred as a result of that event.[302]

If the AER is to maintain its 'bright line' approach to the determination of the materiality threshold, however, ETSA Utilities propose that, at a minimum, the capital expenditure materiality threshold should not be based on a percentage of the annual return on and of capital expenditure, but rather the actual dollar spend on the project for that regulatory year or over the life of the event. Further, the relevant threshold should be considerably lower than what the AER's threshold based on a percentage of the annual return equates to – being approximately $70 million.

Guidance on what level of expenditure should be considered "material" can be obtained from ETSA Utilities' licence and recommendations from the AEMC on the Regulatory Investment Test for Distribution as set out below:

- Clause 14 of ETSA Utilities' distribution licence requires ETSA Utilities to investigate other alternatives (eg demand management) to a network solution for a "significant expansion" of the distribution network. Guideline No. 12, which relates to demand management for electricity networks provides that an RFP should be undertaken for a network project with a likely capital cost of between $2 and $10 million (with the Rules dealing with projects that have a total capital cost of greater than $10 million).[303] This indicates that projects with a capital cost of greater than $2 million may be considered to be significant; and
- The AEMC, in their final report, Review of National Framework for Electricity Distribution Network Planning and Expansion, dated 23 September 2009, recommends that the Regulatory Investment Test for Distribution (RIT-D) apply for any project where the capital cost exceeds $5 million.[304] The AEMC believed that this threshold would "effectively focus the RIT-D on more significant investments" .[305] ETSA Utilities considers that the comments of the AEMC, in considering an investment of $5 million
  to be significant for the purposes of the RIT-D, also lends support for the capital expenditure materiality threshold to be set considerably lower than the threshold in the AER's Draft Determination (which in effect sets a threshold of around $70 million). ETSA Utilities argues that a more appropriate level would be $5 million.

In summary, a threshold for general nominated pass through events based on 1 percent of annual forecast revenue is far too onerous, as this in effect sets a threshold of $70 million. 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, and ETSA Utilities has incorporated a threshold of $5 million of capital and/or operating expenditure in this Revised Proposal.

ETSA Utilities' response to the AER's materiality threshold for specific nominated pass through events

ETSA Utilities notes the AER's determination of a threshold based on the administrative costs of assessing an application for a specific nominated pass through event and has adopted this in its Revised Proposal.

302 ETSA Utilities, ETSA Utilities Regulatory Proposal 2010–2015, July 2009, p.192

303 ESCoSA, *Demand Management for Electricity Distribution Networks: Electricity Industry Guideline No. 12*, July 2007, p 12.

304 AEMC, *Review of National Framework for Electricity Distribution Network Planning and Expansion: Final Report*, 23 September 2009, p 49.

305 AEMC, *Review of National Framework for Electricity Distribution Network Planning and Expansion: Final Report*, 23 September 2009, p 50 (emphasis added).

ETSA Utilities' conclusions to the AER's materiality threshold for nominated pass through events

Revised Proposal

Given the issues and concerns raised above, ETSA Utilities considers that it is appropriate that the AER's approach to materiality should involve a subjective consideration of the financial impact of the event. This approach is consistent with current regulatory pass through arrangements applying to ETSA Utilities.

Nonetheless, ETSA Utilities has incorporated in this Revised Proposal the AER's determination of a threshold based on the administrative costs of assessing an application for a specific nominated pass through event.

As noted above, if the AER determines that a 'bright line' materiality threshold should apply for a general nominated pass through event, ETSA Utilities submits that it should be the total costs attributable to that event with the threshold being $5 million of expenditure over the life of the project. Further, the costs per event should be calculated as the aggregate of both the operating and capital expenditure incurred.

8.7

NOMINATED PASS THROUGH EVENTS

8.7.1
Industry Standards Change Event

ETSA Utilities' Original Proposal

In chapter 8 of its Original Proposal, ETSA Utilities proposed that a nominated pass through should be allowed for an industry standards change event.[306]

The following definition of an industry standards change event was proposed:

an industry standards change event occurs if:

a) *as the result of a decision of a court, standards authority, Government or Government authority, or outcome of an inquiry commissioned by a Government or Government authority, a prudent operator, acting reasonably, would undertake particular action; and*
b) *in undertaking that action, ETSA Utilities incurs material costs which it will not otherwise recover through an increase in distribution revenue.*

By way of example, ETSA Utilities noted the Victorian Government's Royal Commission into the 2009 Victorian bushfires as such an event.[307]

306 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.189.
307 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p. 190.

The AER's Draft Determination

In its Draft Determination, the AER rejected ETSA Utilities' proposal for an industry standards change to be a specific nominated pass through event, as it considered that it was not "highly likely" that such an event would occur.[308] The AER noted that:

> *ETSA Utilities has not provided any information to suggest that such decisions are expected, nor as to the form or content of any such decisions.*

The AER further noted that if an industry standards change event was to arise during the regulatory period which had a material impact on ETSA Utilities' costs, the event may constitute a general nominated pass through event and the AER would assess any such application with reference to its Draft Determination and the Rules.[309]

ETSA Utilities' Response to the AER's Draft Determination

ETSA Utilities maintains the position in its Original Proposal. Putting to one side the issue of whether the criteria of "highly likely" is appropriate, ETSA Utilities in fact considers there to be a high probability that an industry standards change event will occur over the next regulatory period. In particular, ETSA Utilities submits that the findings of the 2009 Victorian Bushfires Royal Commission (the Bushfires Commission) could constitute such an event.

As discussed in ETSA Utilities' Original Proposal, the outcome of that inquiry will very likely provide insights into the management of networks, particularly in the Southern Australian environment, which would influence how a prudent operator should manage its network. Similar outcomes may arise from any similar inquiry into the recent bushfires in Western Australia.

ETSA Utilities considers that, while the specific recommendations of the Bushfires Commission are difficult to predict, there are already indications that the Bushfires Commission is paying close attention to the issue of industry standards. ETSA Utilities notes the following from the transcript to the proceedings of the Bushfires Commission:

- A statement tendered to the Bushfires Commission by the Executive Director of the Energy Division of the Victorian Department of Primary Industry, Marianne Lourey, is referred to, which notes an initiative of the Victorian Government to establish a national workshop in early 2010 to facilitate the consideration of changes to or upgrading of distribution networks to reduce the risk of bushfire starts;[310]

308 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 406.
309 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 406.
310 Transcripts of the proceedings of the 2009 Victorian Bushfires Royal Commission (15 December 2009), p. 13440 [13–30].

- The Bushfires Commission discusses in detail the level of skills and accreditation of DNSP employees and contractors responsible for asset audits, indicating the potential for recommendations that DNSPs should adopt more stringent performance audits and implement improved training programs, including more frequent "refresher" courses[311]; and
- The transcripts from the Bushfires Commission indicates the potential for adjustments in the methodologies for asset inspection to further ensure network integrity under severe weather conditions on high bushfire risk days.[312] If a recommendation such as this was to emerge from the Bushfires Commission this would not only substantially increase the costs of asset inspections but also likely require the bringing forward of asset replacements.

Given the indications emerging from the Bushfire Commission in particular, ETSA Utilities submits that there is a high probability that a significant change in industry standards could take place over the next regulatory control period.

In any case, and as noted above, there is no basis in the Law or the Rules for the exclusion of the industry standards change event on the basis that it is not "highly likely" that ETSA Utilities will be required to undertake activities associated with such an event. The question is whether the nomination of this event in the distribution determination to apply to ETSA Utilities is consistent with the requirements of the Rules and the Law. If an industry standards change occurs and ETSA Utilities is not able to recover the costs associated with this event, it could impact on the ability of ETSA Utilities to recover its efficient costs.

Revised Proposal

The industry standards change event as specified by ETSA Utilities as a nominated pass through event is consistent with the requirements of the Law and the Rules and should be accepted by the AER. The inclusion of this event will help to ensure that ETSA Utilities is provided with a reasonable opportunity to recover its efficient costs, and it helps to ensure that ETSA Utilities has effective incentives in order to promote economic efficiency.

311 See Transcripts of the proceedings of the 2009 Victorian Bushfires Royal Commission (18 November 2009), examination of Kelven Barnbrook, Energy Training Centre, p. 11194 [13] to p. 11246 [17] and examination of Donald Ying, UAM, p. 11258 [20] to p. 11285 [29] and Transcripts of the proceedings of the 2009 Victorian Bushfires Royal Commission (19 November 2009), examination of Jason Leech, p. 11408 [21] to p. 11440 [19].

312 See Transcripts of the proceedings of the 2009 Victorian Bushfires Royal Commission (18 November 2009), examination of Harry Better, p. 11302 [8] to p. 11336 [3] and examination of Jason Leech, p. 11408 [21] to p. 11440 [19].

8.7.2 Interim Period Event

ETSA Utilities' Original Proposal

In chapter 8 of its Original Proposal, ETSA Utilities proposed that a nominated pass through should be allowed for an interim period event.[313]

The following definition of an interim period event was proposed:

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.

ETSA Utilities noted in its Original Proposal that interim period events, but for their timing, would be pass through events and have therefore already met the substantive requirements to be pass through events. In addition ETSA Utilities noted that while the trigger occurred in the previous regulatory period, the cost impact was felt in the relevant regulatory period and that it would be inconsistent with good regulatory practice to fail to take into account costs which, had they been incurred earlier would have been recoverable. [314]

The AER's Draft Determination

The AER considered that they were not empowered under the NEL to nominate an event that takes place before the next regulatory control period. Accordingly, the AER rejected ETSA Utilities' proposal for an interim period event to be allowed as a specific nominated pass through event.[315]

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities maintains the position in its Original Proposal. Under clause 6.12.1(14), the AER is required to make a decision on the additional pass through events that are to apply for the regulatory control period and which cause additional costs of providing distribution services. This clause does not restrict the ability to nominate events in a distribution determination solely to events that occur during the regulatory control period under consideration. The relevant decision being made by the AER is as to what events apply as pass through events to a particular regulatory control period, not whether the event occurs during a particular regulatory control period.

313 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.191.

314 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.191.

315 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 407.

Revised Proposal

The interim period event as defined in ETSA Utilities' Original Proposal is an event that would apply to the 2010 – 2015 regulatory control period, although it relates to events that may occur prior to the commencement of that regulatory period that give rise to costs in the 2010 – 2015 regulatory control period. Accordingly, ETSA Utilities submits that an interim period event is within the scope of the AER's decision making powers for the 2010–2015 regulatory control period, and for the reasons outlined in its Original Proposal, ETSA Utilities considers that such an event should be allowed as a nominated pass through event for the 2010–2015 regulatory control period.

ETSA Utilities will provide further material in relation to the interim period event as part of its response to the Draft Determination.

8.7.3 Retailer Failure Event

ETSA Utilities' Original Proposal

In chapter 8 of its Original Proposal, ETSA Utilities proposed that a nominated pass through should be allowed for a retailer failure event.[316]

The following definition of a retailer failure event was proposed:

a retailer failure event occurs if:

a) a retailer is placed in administration, liquidation or their licence is revoked; and

b) as a consequence, ETSA Utilities does not receive revenue to which it was otherwise entitled.

ETSA Utilities noted in its Original Proposal, that while the business takes steps to protect itself against retailer failure through the credit support arrangements in its use of system agreements, obtaining and amending such agreements can often be a protracted process. Any delay in procuring such an agreement exposes ETSA Utilities to the cost consequences of the failure of that retailer, without the capacity to recover such costs.[317]

The AER's Draft Determination

In its Draft Determination, the AER rejected ETSA Utilities' proposal for a retailer failure event to be a specific nominated pass through event, as it considered that ETSA Utilities had not presented evidence to suggest that such an event was "highly likely" to occur. The AER also did not consider it appropriate to define cost pass through events which negate incentive to efficiently manage risk.[318]

The AER noted that if a retailer failure event was to arise during the regulatory control period which had a material impact on ETSA Utilities' costs, the event may constitute a general nominated pass through event, and the AER would assess any such application with reference to its Draft Determination and the Rules.[319]

ETSA Utilities' response to the AER's Draft Determination

ETSA Utilities maintains the position in its Original Proposal. Putting to one side the issue of whether the criteria of "highly likely" is appropriate, ETSA Utilities in fact considers there to be a high probability that a retailer failure event will occur over the next regulatory period.

In support of this position, ETSA Utilities notes the following:

- first, ETSA Utilities considers there to be a high level of risk in the South Australian retail electricity market following the introduction of full retail contestability and the number of retailers that have entered the market. As at 30 June 2009 there were 19 retailers licensed to operate within South Australia, with 11 selling to small customers.[320] The level of risk of a retailer failure event has been demonstrated both in South Australia and more broadly by the following events;
  - since the submission of ETSA Utilities' Original Proposal, an electricity retailer operating in South Australia, Jack Green, has been suspended from trading in the National Electricity Market under clause 3.15.21(f) of the Rules due to the company entering into voluntary liquidation. As a consequence of this, ETSA Utilities has been directed by ESCoSA to undertake its role as RoLR for that retailer's customers (ETSA Utilities' role as the South Australian RoLR is discussed below);
  - on 22 June 2007, the National Electricity Market Management Company Limited (NEMMCO) issued a default and suspension notice to the retailer, Energy One Limited, an electricity retailer with customers in NSW, Queensland, Victoria and the ACT; and
- secondly, the Victorian Essential Services Commission (ESC) recognised the possibility for a retailer failure event in its final decision for the 2006–2010 Electricity Distribution Price Review and allowed for electricity distributors to apply for a pass through for the incremental costs arising from a 'declared' Retailer of Last Resort (RoLR) event where those costs are material and cannot be recovered through another mechanism.[321]

316 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.190.

317 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.190.

318 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 406.

319 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 406.

320 ESCoSA, *Annual Report 2008 – 2009*, p 26.

321 ESC, Electricity Distribution Price Review 2006–10 Final Decision Volume 1 Statement of Purpose and Reasons (October 2005 Price Determination as amended in accordance with a decision of the Appeal Panel dated 17 February 2006), p. 488.

As discussed in its Original Proposal, ETSA Utilities takes steps to protect itself against retailer failure through the credit support arrangements in its use of system agreements.[322] ETSA Utilities and South Australian electricity retailers are obliged, as a mandatory licence condition, to enter into a Co-ordination Agreement with each other, on terms approved by the South Australian regulator, ESCoSA.[323] Under such Co-ordination Agreements, ETSA Utilities appoints retailers to act as its agent in collecting distribution charges levied on customers by ETSA Utilities through its connection and supply contracts. Consequently, ETSA Utilities is entitled to seek under the agreement an unconditional undertaking to secure performance of a retailer's obligation to pay where that retailer does not have a credit rating, or its credit rating is less than BBB-(credit support).

However, for the reasons outlined below, ETSA Utilities submits that these protections are not necessarily sufficient to ensure that ETSA Utilities is safeguarded against all the costs it may incur as a result of failure of a retailer over the regulatory period. Accordingly, ETSA Utilities submits that a nominated pass through should be allowed to enable the recovery of the costs associated with a retailer failure event.

Exposure due to time delay in securing Co-ordination Agreements

As noted in its Original Proposal, ETSA Utilities often experiences difficulty in securing or amending a retailers' credit support undertaking as a result of the protracted process of obtaining Co-ordination Agreements from retailers. This period of time can be significant and ETSA Utilities has set out some further information on this issue in a confidential document that will be provided to the AER.

As the only DNSP in South Australia, ETSA Utilities bears considerable exposure as a result of retailers who refuse to provide the requisite credit support.

Shortfall in net costs as a result of retailer failure

Under the credit support arrangements in the statutory Co-ordination Agreements, the amount of credit support which ETSA Utilities is entitled to secure from a retailer is for an amount not exceeding 3 months worth of the distribution charges which are estimated would be incurred by that retailer's customers in the 3 month period after a failure event.[324]

However, ETSA Utilities submits that even if the credit support undertaking is secured, the net cost associated with a given retailer's failure may be well in excess of the maximum amount which ETSA Utilities is permitted to secure under the statutory Co-ordination Agreement. That is, while ETSA Utilities has in place robust risk management processes to minimise the liability a retailer has to ETSA Utilities, it can often be the case that a retailer's credit support undertaking is insufficient to cover its actual liability to ETSA Utilities. While under section 14.3 of the Co-ordination Agreement ETSA Utilities may request credit support from a retailer for an amount equal to 3 months of estimated DUoS charges, any significant increase in those charges (for instance as a result of an increase in that retailer's customer base) would require ETSA Utilities to make a new request.

As noted above, securing such amendments can be a protracted process which exposes 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 liability to ETSA Utilities at any given time.

Changes to the credit support scheme applying to ETSA Utilities

ETSA Utilities has recently been informed that the South Australian regulator, ESCoSA, intends to propose amendments to the credit support arrangements currently in place in South Australia through the Co-ordination Agreements. ESCoSA has indicated that its preferred approach would be to adopt the credit support arrangements which now exist in Victoria and which emerged from a review of that states' credit support arrangements undertaken in 2006 by Victoria's Essential Services Commission (ESC).

In addition, the national energy customer framework currently in development by the Retail Policy Working Group under the auspices of the Ministerial Council on Energy will involve the development of a new national Retail Support Contract which will include, when implemented, provision for uniform credit support arrangements across Australia. While it is not clear when the national framework will be put into operation, ETSA Utilities understands that the working group's preferred approach to credit support is that it will be similar the Victorian model (in that retailers will be provided with an unsecured credit allowance by the DNSP).

ETSA Utilities submits that, given these developments, it is highly likely that, in the next regulatory control period, ETSA Utilities will be subject to different credit support arrangements than currently exist, and, for the reasons outlined below, that those new arrangements will significantly increase the risk which ETSA Utilities faces in the event of a retailer failure.

The Victorian credit support model is based on the methodology used in the United Kingdom and emerged from a 2006 review undertaken by the Allen Consulting Group (ACG) under direction from Victoria's ESC.[325]

322 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.190.

323 See. for example, clause 22 of ETSA Utilities' distribution licence, issued by ESCoSA on 11 October 1999 and last varied on 7 November 2008.

324 Co-ordination Agreement, Clause 14.3

325 ESC, Credit Support Arrangements, Final Decision (October 2006)

The Victorian approach diverges from South Australia's current regime in that, while currently ETSA Utilities is entitled to seek credit support from any retailer that does not have a credit rating, or has a credit rating less than BBB-, the proposed Victorian approach adopts a sliding scale of credit support based on the difference between the retailer's unsecured credit allowance (calculated as a percentage of the DNSP's total DUoS charges) and its average billed and unbilled distribution service charges liability over a three month period.[326] This approach is designed in part to reduce the barriers to entry for small retailers wishing to enter into the retail electricity market such as significant credit support requirements.[327]

While the proposed credit support arrangements will notionally apply to all retailers, as noted by ESCoSA, fewer retailers will in effect be required to provide credit support to ETSA Utilities than is currently the case.[328]

ETSA Utilities also notes that both the credit support approach adopted in Victoria, and the proposed South Australian regime, are predicated on a DNSP being able to pass the costs associated with a retailer failure through to electricity customers, in the event that the credit support arrangements are found to be inadequate. That is, both regimes favour the promotion of greater retail competitiveness through reducing barriers to entry in the knowledge that a DNSP can recover the difference between credit support and actual loss directly from electricity customers through a pass through mechanism.[329] The pass through is subject to a DNSP appropriately managing its risk exposure within the regulatory arrangement.

ETSA Utilities submits that it would be unlikely that a change in the regulatory structure surrounding credit support arrangement in South Australia would be considered a regulatory change event pass through under the Rules, as the costs associated with such an event would not manifest until, and only in the event of, a retailer failure. Accordingly, ETSA Utilities submits that the only way for ETSA Utilities to recover any costs it may incur in the event of a retailer failure is to specifically provide for it as a nominated pass through event as proposed in its Original Proposal.

For the reasons outlined above, ETSA Utilities considers that a retailer failure event should be a nominated pass through event for the 2010–2015 regulatory period. ETSA Utilities is of the view that such an event is appropriate both under the credit support arrangements currently operating in South Australia, and in the event that those arrangements are amended in line with the Victorian model.

ETSA Utilities' response to retailer failure event pass through

As noted above, there is no basis in the Law or the Rules for the exclusion of the retailer failure event on the basis that such an event is not "highly likely", and in any case, ETSA Utilities has provided evidence that there is in fact a high probability that such an event will occur. The question is whether the nomination of this event in the distribution determination to apply to ETSA Utilities is consistent with the requirements of the Rules and the Law. If a retailer failure event occurs and ETSA Utilities is not able to recover the costs associated with this event, it could impact on the ability of ETSA Utilities to recover its efficient costs.

The retailer failure event as specified by ETSA Utilities as a nominated pass through event is consistent with the requirements of the Law and the Rules, and should be accepted by the AER. The inclusion of this event will help to ensure that ETSA Utilities is provided with a reasonable opportunity to recover its efficient costs, and it helps to ensure that ETSA Utilities has effective incentives in order to promote economic efficiency.

In relation to the AER's comment that the AER does not consider it appropriate to define cost pass through events which negate incentive to efficiently manage risk, as ETSA Utilities has noted above, the inclusion of a particular nominated pass through event does not automatically result in costs being passed through – once an event has occurred, the AER then determines the appropriate pass through amount (if any) consistent with the national electricity objective.[330]

Revised Proposal

For the reasons outlined above, ETSA Utilities considers that a retailer failure event should be a nominated pass through event for the 2010–2015 regulatory period. ETSA Utilities is of the view that such an event is appropriate both under the credit support arrangements currently operating in South Australia, and in the event that those arrangements are amended in line with the Victorian model.

The retailer failure event as specified by ETSA Utilities as a nominated pass through event is consistent with the requirements of the Law and the Rules and should be accepted by the AER. The inclusion of this event will help to ensure that ETSA Utilities is provided with a reasonable opportunity to recover its efficient costs, and it helps to ensure that ETSA Utilities has effective incentives in order to promote economic efficiency.

326 A copy of a draft letter (dated 17 December 2009 pg 6) to be sent to stakeholders for consultation along with a Gilbert & Tobin Report titled "Review of South Australia's Electricity Credit Support Arrangements" dated 8 October 2009" proposing the adoption of the Victorian Credit Support arrangements (confidential attachment).

327 ESC, Credit Support Arrangements Draft Decision (July 2006), p.14.

328 Letter from ESCoSA to ETSA Utilities dated 17 December 2009, p. 7.

329 ESC, Credit Support Arrangements Draft Decision (July 2006), p.3.

330 Standing Committee of Officials of the Ministerial Council on Energy, SCO Response to Draft NER, August 2007, Table 1, p 87.

8.7.4
Retailer of Last Resort (ROLR) Obligation Event

Under section 23 of the *Electricity Act 1996* (SA), ETSA Utilities is obliged to sell and supply electricity to particular customers in the event that:

- a retailer's licence to carry on retailing of electricity is suspended or cancelled; or
- whose right to acquire electricity from the market for wholesale trading in electricity is suspended or terminated; or
- who has ceased to retail electricity in the State (RoLR obligation).

While the RoLR obligation was originally due to expire on 30 June 2010, the South Australian Parliament has recently extended the obligation to apply to ETSA Utilities until 30 June 2015. Consequently, at the time of the submission of its Original Proposal, ETSA Utilities was unaware of the need to nominate a pass through in the event of a Retailer of Last Resort obligation event for the 2010–2015 regulatory period.

ETSA Utilities considers that the extension of the RoLR obligation would have been captured by the pass through events nominated in its Original Proposal, in particular the proposed definition of an extraordinary event.[331]

The AER's Draft Determination

The AER's Draft Determination does not deal specifically with the RoLR obligation as defined in this Revised Proposal, as it was not proposed in ETSA Utilities' Original Proposal. However, the AER rejected ETSA Utilities' proposal for a nominated pass through for an extraordinary event,[332] and, in part in response to the rejection of that event, ETSA Utilities has included a RoLR obligation event in this Revised Proposal.

The AER did note that the South Australian Government intended to provide a rule change proposal to the AEMC in relation to this issue which would include RoLR services in the distribution determination applicable to the next regulatory control period. The AER also noted that it will take into consideration the rule change process in its determination.[333]

ETSA Utilities' response

As discussed above in relation to the retailer failure event pass through, ETSA Utilities is of the view that there is high probability that it will be subject to a retailer failure event in the next regulatory period. As also noted above, this has already occurred with the retailer, Jack Green, being suspended from trading in the National Electricity Market under clause 3.15.21(f) of the Rules due to the company entering into voluntary liquidation. As a result of the amendments to the Electricity Act 1996 (SA), ETSA Utilities will be subject to the costs associated with its role as the RoLR until the end of the 2010–2015 regulatory period. Accordingly, ETSA Utilities proposes that the AER accept the nomination by ETSA Utilities of a pass through of costs associated with a Retailer of Last Resort Obligation event.

ETSA Utilities has undertaken significant steps in order to prepare for such an event, including the investigation of a number of solution options. While ETSA Utilities has investigated several potential options, the only option it considers to be a prudent and efficient and available to it is where ETSA Utilities enters into a contract by which the applicable RoLR customers are transferred to South Australian 'host retailer', AGL when a ROLR event occurs. A copy of the contract is provided with this Revised Proposal.[334]

While there is already an arrangement in place for AGL to provide critical support to ETSA Utilities in the event of a RoLR event, ETSA Utilities is at an advanced stage of renegotiating that arrangement such that the arrangements described above will apply over the next 12 month period.

In relation to this agreement, ETSA Utilities notes the following:

- ETSA Utilities approached every retailer which it considered as having the retail capacity to handle the potential number of customers which ETSA Utilities may inherit following a ROLR event with a view to negotiating such an arrangement, but only the host retailer, AGL, was prepared to enter into such an arrangement.
- Under the terms of the existing agreement, the maximum amount of electricity that ETSA Utilities would be able to purchase from AGL would be capped at 225,000 MWh or less. This would provide sufficient electricity to cater for a RoLR event, excluding the failure of any of the 5 largest retailers in South Australia. However, ETSA Utilities is currently in the process of negotiating a revised agreement with AGL, which would cap this amount at 1,000,000MWh, and therefore provide coverage for a RoLR event excluding failure of the 2 largest retailers in SA (including AGL itself).
- Under such an arrangement, ETSA Utilities' establishment costs are immaterial, and hence ETSA Utilities has not incorporated these within its operating expenditure forecasts, however, this option does require ETSA Utilities to have the capacity to be able to pass through costs should the agreement ever need to be activated.
- The arrangement being entered into does not provide full protection as it is only a 12 month arrangement and AGL could choose not to renew. Furthermore, the agreement specifically excludes provision for failure of the two largest retailers – including, obviously, AGL itself. Should AGL choose not to renew, or either of AGL or the second-largest retailer fail, ETSA Utilities would require pass through of a completely different level of costs, likely including costs associated with the establishment of retail systems and processes, as well as lost revenue and electricity consumption fees.
- ETSA Utilities is not able to manage or limit the risk of a RoLR event and would not stand to benefit from the proposed arrangement with AGL. The arrangement would simply allow for the passing-through of costs as incurred.

331 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.188.

332 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 406.

333 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 22

334 AGL / ETSA Utilities Retailer of Last Resort Agreement (20 May 2009).

ETSA Utilities considers it unlikely that from a commercial perspective that a retailer would enter into an agreement with ETSA Utilities, which assumes the spot price risk that is inherent when supplying electricity to stranded RoLR customers.

As noted above, ETSA Utilities is obliged to sell and supply electricity to particular customers in the event that a South Australian retailer fails. The scope of ETSA Utilities' obligations under the RoLR scheme, and the manner in which it may determine charges for the costs incurred are set out in ESCoSA's RoLR Pricing Guideline.[335]

ETSA Utilities considers that it should be allowed the reasonable opportunity to recover the efficient cost of compliance with this regulatory obligation as contemplated by section 2D(1)(b)(v) of the Law. In this regard, ETSA Utilities notes the position put forward by the South Australian Government in a letter to the AER dated 8 December 2009.[336]

Revised Proposal
For the reasons outlined above, ETSA Utilities proposes that a Retailer of Last Resort Obligation event be allowed as a nominated pass through event for the regulatory period 2010–2015, adopting the following definition:

a Retailer of Last Resort Obligation event occurs if:
a) ETSA Utilities is called upon to act as 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(s).

8.7.5 Carbon Pollution Reduction Scheme

ETSA Utilities' Original Proposal
In chapter 8 of its Original Proposal, ETSA Utilities considered that it may be affected by the introduction by the Federal or South Australian Governments of an emissions trading scheme, and that this would constitute a regulatory change event or service standard event as defined in the Rules.[337]

In the event that the AER did not consider that such an event would be covered by a regulatory change event or service standard event pass through, however, ETSA Utilities proposed to nominate a carbon emissions trading scheme event as a nominated pass through event.

The AER's Draft Determination
In its Draft Determination, the AER was uncertain as to whether an emissions trading event would be captured by the defined regulatory change event under the Rules, but considered that such an event was highly likely to occur.

Accordingly, the AER nominated a Carbon Pollution Reduction (CPRS) event as a nominated pass through event for the 2010–2015 regulatory period.[338] The AER accepted the CPRS event as a specific nominated pass through event with the following definition:

> *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.*

ETSA Utilities' response to the AER's Draft Determination

Revised Proposal
ETSA Utilities has incorporated the AER's Draft Determination in relation to the CPRS event pass through, on the basis that the definition proposed by the AER can be construed as covering all obligations imposed upon 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 through some other mechanism.

335 Electricity Industry Guideline Number 8: Retailer Of Last Resort Pricing Guideline (July 2007).

336 Letter to the Chairman of the AER, Steve Edwell, from Sean Kelly, Executive Director, Energy Division of the South Australian Department of Transport, Energy and Infrastructure, dated 8 December 2009.

337 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.186.

338 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 403.

8.7.6 Kangaroo Island Cable Failure Event

ETSA Utilities' Original Proposal

In chapter 6 of its Original Proposal, ETSA Utilities proposed capital expenditure of $95 million for the improvement of Kangaroo Island's network security.[339]

ETSA Utilities proposed that an additional undersea cable be constructed to Kangaroo Island to supplement the existing 33kV island 'backbone'. ETSA Utilities proposed that the additional cable would:

1. mitigate the risk to the island's electric supply as a result of the catastrophic failure of the existing 33kV cable; and
2. resolve the artificial constraint on development due to the reticence of large customers to make the significant capital contributions required to allow them to connect to the current network.

The AER's Draft Determination

The AER engaged experts, PB, to conduct a review of ETSA Utilities' Original Proposal in relation to, among other things, the Kangaroo Island network security project.[340]

The AER concluded that the risks associated with the failure of the undersea cable are mitigated by standby generation and private generation. The AER determined that replacing the undersea cable in 2016 and augmenting the 66kV sub-transmission network in 2025 would result in the least cost outcome. The AER therefore considered that the Kangaroo Island project should be removed from ETSA Utilities' forecast capital expenditure.[341]

ETSA Utilities' response to the AER's Draft Determination

Without necessarily agreeing with the reasons set out in the AER's Draft Determination, ETSA Utilities' Revised Proposal incorporates the AER's Draft Determination with respect to expenditure on the Kangaroo Island network security project. The Revised Proposal removes the Kangaroo Island project from the forecast capital expenditure. In its place, this Revised Proposal includes a pass through event for both the capital and operating expenditure associated with the failure of the 33kV undersea cable to Kangaroo Island, if such an event were to materialise.

ETSA Utilities submits that the need to undertake any significant capital and/or operating expenditure in relation to the supply of electricity to Kangaroo Island should be treated as analogous to a contingent project under the transmission rules.[342] That is, in the event that supply to the island is disrupted in the next regulatory control period, ETSA Utilities should be provided with a mechanism to recover the costs of maintaining supply throughout that period and the costs associated with the cable's repair or replacement.

Accordingly, ETSA Utilities propose that a Kangaroo Island Cable Failure Event be allowed as a nominated pass through event for the regulatory control period 2010–2015.

Revised Proposal

ETSA Utilities propose that a Kangaroo Island Cable Failure Event be allowed as a nominated pass through event for the regulatory control period 2010–2015, adopting the following definition:

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.

339 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.148.

340 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p.148.

341 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014-15*, 25 Nov 2009, p 151.

342 National Electricity Rules, Clause 6A.8.1.

9

We do everything in our power to deliver yours

Demand management

9

DEMAND MANAGEMENT

In this chapter of the Revised Proposal, ETSA Utilities responds to the AER's Draft Determination on aspects of demand management, and in particular on the implementation of the Demand Management Incentive Scheme (DMIS).

ETSA Utilities has an extensive record of accomplishment in the field of demand management. The issue of demand management is of considerable importance in South Australia because of the particularly peaky nature of the South Australian summer load. ETSA Utilities' experience with, and understanding of, demand management schemes has been facilitated by the enlightened regulatory arrangements relating to demand management, which were applied during the current EDPD.

In the Original Proposal, ETSA Utilities factored the effects of foreseen demand management into its forecasts of sales and demand and the accompanying forecasts of capital and operating expenditures.

The AER's likely approach to the DMIS to apply to ETSA Utilities was originally set out in the Framework and approach paper.[343] ETSA Utilities' Original Proposal and submissions by other participants raised concerns with aspects of the DMIS, including the proposed level of funding and the incentive structure.

On 6 August 2009, the AER held a public forum in Adelaide on the Original Proposal submitted by ETSA Utilities. At that meeting, a number of stakeholders expressed concern over the lack of incentive for effective demand management present in the AER's Draft Determination.

In the Draft Determination, the AER confirmed its earlier position on the implementation of the DMIS.[344]

ETSA Utilities shares stakeholders' concerns that the AER's proposed approach to demand management in the 2010-15 regulatory control period will not operate in a manner to encourage any appreciable level of demand management. Accordingly, this Revised Proposal recommends improving the incentive structure by extending the application of Part B of the DMIS to all demand management projects. ETSA Utilities also maintains the position in its Original Proposal that the assessment criteria for the DMIA should specifically recognise the likelihood that a project or program may fail to deliver the intended outcome or fail to deliver the outcome in a timely manner.

343 Final Framework and approach paper – ETSA Utilities 2010-15, AER, November 2008, p98.

344 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, Chapter 14.

9.1

RULE AND JURISDICTIONAL REQUIREMENTS

9.1.1
Demand management and capital and operating expenditure forecasts

Clause 5.6.2 of the Rules sets out the procedures to be followed by a DNSP in developing the network. This includes in clause 5.6.6(b)(4) the consideration of non-network alternatives to augmentation of the network.

Clauses 6.5.6 and 6.5.7 set out the operating and capital expenditure objectives respectively. These are required to be achieved by the DNSP's forecast expenditure requirements. The objectives in (a)(1) require a DNSP to "meet or manage" the expected demand for standard control services throughout the regulatory control period.

9.1.2
Jurisdictional requirements

ETSA Utilities is required under subsection 23(1)(n)(x) of the Electricity Act 1996 (SA) to consider cost effective demand management alternatives to network expansion, and to prepare and publish reports relating to demand management investigations and measures.[345] ESCOSA's Electricity Industry Guideline No. 12 sets out these requirements, which will continue to apply during the course of the 2005-10 regulatory control period, or until such time as the guideline is superseded when the provisions of the national annual planning and reporting framework for DNSPs are implemented.[346],[347]

Guideline 12 requires ETSA Utilities to:

- publish an annual report, detailing the projected limitations of its distribution system; and
- invite proposals for suitable alternative non-network solutions to overcome the projected network limitations.

Guideline 12 applies to projects with an estimated value of between $2 and $10 million. Distribution projects with a value in excess of $10 million are subject to the requirements of clause 5.6.5A of the Rules in relation to the Regulatory Investment Test.[348]

9.1.3
The Demand Management Incentive Scheme

As part of a distribution determination, the AER is obliged under clause 6.12.1(9) of the Rules to make a constituent decision concerning the application of any demand management incentive scheme to apply to ETSA Utilities. The AER has established such a Demand Management Incentive Scheme (DMIS) in accordance with clause 6.6.3 of the Rules.[349]

345 Electricity Act 1996 (South Australia) Version 1.7.2009.

346 Demand Management for Electricity Distribution Networks - Electricity Industry Guideline No. 12, Essential Services Commission of South Australia, July 2007.

347 Final Report - Review of National Framework for Electricity Distribution Network Planning and Expansion, AEMC, 23 September 2009

348 Final Decision - Regulatory Test version 3 & Application Guidelines, Australian Energy Regulator, November 2007.

349 Final Decision - Demand Management Incentive Scheme, Energex, Ergon Energy and ETSA Utilities, 2010–15, AER, October 2008.

9.2

ETSA UTILITIES' ORIGINAL PROPOSAL

The main positions which were expressed in ETSA Utilities' Original Proposal are summarised below.

9.2.1
Demand management and capital and operating expenditure forecasts

Chapter 9 of ETSA Utilities' Original Proposal described the extensive range of demand management initiatives, which it has trialled during the 2005-10 EDPD. The description of those initiatives is not repeated in this Revised Proposal. However, it should be noted that ETSA Utilities has established its position as a national leader in the research and development of demand management solutions.

The future demand management solutions which may be pursued during the 2010-15 regulatory control period were also described. These included:

- the continuation of a Power Factor Correction program, with education and incentives for business customers to improve the power factor of their installations; and
- further trial and costing of the Peakbreaker+scheme. This is a refinement of earlier direct load control schemes which control air conditioning compressors on a rotational basis, with two way radio communications to offer a range of additional features usually associated with Advanced Metering Infrastructure.

In chapter 5 of the Original Proposal, ETSA Utilities provided peak demand and sales forecasts for the 2010-15 regulatory period. Those forecasts contained a detailed assessment of the effect of demand management and other greenhouse and energy efficiency measures on both demand and sales.

The capital and operating expenditure forecasts in chapters 6 and 7 of ETSA Utilities' Original Proposal demonstrated how the capital and operating expenditure objectives set out in the Rules had been met. These forecasts made allowance for the development of economically efficient demand management.

9.2.2
The Demand Management Incentive Scheme

In the Original Proposal, ETSA Utilities generally supported the AER's DMIS but raised the following concerns regarding its implementation:

- Part A of the DMIS, the demand management investment allowance, requires that investigations undertaken by ETSA Utilities would be subject to ex-post assessment by the AER.

  ETSA Utilities submitted that the criteria for this ex-post assessment must adequately recognise the risk that a demand management investigation (often involving unproven technology) may fail to produce its intended outcome or may not produce the intended outcome in a timely manner; and

- Part B of the DMIS, involving the recovery of revenue foregone due to the implementation of demand management initiatives, is restricted to those projects undertaken under Part A of the scheme.

  ETSA Utilities provided arguments to support its contention that the foregone revenue provision should not be restricted to projects implemented under Part A of the scheme. Rather, this provision should be extended to include other demand management options undertaken during the regulatory control period.

9.3

THE AER'S DRAFT DETERMINATION

The main features of the AER's Draft Determination and its response to the issues raised by ETSA Utilities were as follows.

The sales, demand and expenditure forecasts which formed part of ETSA Utilities' Original Proposal were subjected to review by consultants appointed by the AER, as follows:

- the sales forecast was reviewed by the Planning Council (this aspect of its activities was subsumed into the AEMO);
- the global and spatial demand forecast was reviewed by AEMO; and
- the capital and operating expenditure forecasts were reviewed by Parsons Brinckerhoff Strategic Consulting (PB).

Each of these forecasts made allowances for the expected effect of demand management initiatives, as well as the impact of other greenhouse and energy efficiency related programs.

The AER did not accept ETSA Utilities' sales forecast. This is discussed in detail in chapter 5 of this Revised Proposal. With regard to the capital and operating expenditure forecasts, the AER did not accept certain aspects of these forecasts. These forecasts are reviewed in chapters 6 and 7 of this Revised Proposal. However, the AER did come to the following conclusions concerning the inclusion of demand management within those forecasts.

9.3.1
Demand management and capital and operating expenditure forecasts

Before approving forecasts of operating and capital expenditure, the AER required ETSA Utilities to satisfactorily demonstrate that efficient non-network alternatives to capital and operating expenditure had been appropriately considered in the development of forecasts.

PB's review of the capital expenditure forecast observed that:

> *"... non–network alternatives and demand management opportunities are considered and pursued".*[350]

In relation to ETSA Utilities' operating expenditure forecast, the AER concluded:

> *"ETSA Utilities' consideration of efficient non–network solutions was found to be consistent with good electricity industry practice, with efficient non–network alternatives and demand management opportunities being considered and pursued to alleviate network constraints. The efficiency of proposed non–network solutions is evaluated against the benefit of deferring network augmentation".* [351]

The PB review of the operating expenditure forecast observed:

> *"In reviewing the extent to which efficient non–network alternatives are considered by ETSA Utilities to address identified network constraints, PB found that economically viable non–network alternatives are considered as a matter of course before applying network solutions. PB noted that assessment is made to find out whether a non–network alternative is more efficient than a more traditional network augmentation option. PB noted evidence of ETSA Utilities' active development and implementation of demand management practices, and concluded that ETSA Utilities' consideration of non–network solutions and demand management opportunities was consistent with good electricity industry practice".*[352]

350 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 111.

351 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 116.

352 AER, Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15, 25 Nov 2009, p 130.

The AER noted PB's findings, and concluded in relation to the demand management provisions in the operating expenditure forecast:

> *"For the reasons discussed, and as a result of the AER's consideration of ETSA Utilities' regulatory proposal, PB's report and supporting material, the AER is satisfied that ETSA Utilities' forecast demand management opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors."* [353]

9.3.2
The Demand Management Incentive Scheme

In the Draft Determination, the AER confirmed the operation of the DMIS, which comprises two parts:

- ***Part A:*** the demand management incentive allowance (DMIA), to be capped at $3 million over the 2010-15 regulatory control period and allocated in five equal annual instalments of $600,000. An ex-post assessment of the expenditure on projects would be assessed against the criteria in the DMIS; and
- ***Part B:*** permits the recovery of revenue forgone through tariffs for demand management projects. Revenue recovery is uncapped but is only permitted for those projects, which are approved under Part A.

The AER's Draft Determination concerning the operation of the DMIS is unchanged from the provisions which were set out in its Framework and approach paper and Final Determination.

The AER did not accept ETSA Utilities' concern regarding the need to adequately recognise the risk that a demand management investigation under Part A of the DMIS may fail to deliver the intended outcome or fail to deliver the outcome in a timely manner.

The AER also did not accept ETSA Utilities' proposal to broaden the application of Part B of the DMIS by permitting the recovery of foregone revenue from existing and future demand management projects, which were not subject to approval under Part A of the scheme.

353 AER, Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15, 25 Nov 2009, p 231.

9.4

ETSA UTILITIES' RESPONSE TO THE AER'S DRAFT DETERMINATION

9.4.1
Inclusion of demand management in capital and operating expenditure

ETSA Utilities notes and agrees with the AER's decision concerning the inclusion of demand management in the capital and operating expenditure forecasts.

9.4.2
The DMIA allowance

It its Original Proposal, ETSA Utilities did not propose any alteration to the capped DMIA amount of $3 million, which the AER has approved for DMIA expenditure during the 2010-15 regulatory control period. However, ETSA Utilities believes that this level of expenditure does not recognise the views of consumer groups of the need to encourage demand management solutions. In this respect, it needs to be noted that the $3 million allowance represents 0.09% of ETSA Utilities' annual revenue requirement.[354] This is manifestly lower than the maximum level of funding permitted by Ofgem under the IFI regime, applied to electricity distributors in the United Kingdom.[355] The IFI scheme has now been extended to March 2015.[356]

Moreover, the AEMC has now suggested the extension of the DMIA to include the connection of embedded generation.[357] The AEMC proposal has been accepted by the MCE.[358] The AER's cap on the DMIA will not provide for the funding of very many embedded generator connections.

ETSA Utilities contends that the AER should take into account this low level of expenditure under the DMIS in its consideration of ETSA Utilities' proposed treatment of foregone revenue associated with demand management programs undertaken over the regulatory period 2010-15. ETSA Utilities believes that to overcome impediments to demand management, it is appropriate for the AER to consider as a total package, the incentives to undertake demand management and the need to remove barriers to its implementation.

354 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 419.

355 See for example Ofgem's summary: Reports by Distribution Network Operators (DNOs) on Innovation Funding Incentive (IFI) and Registered Power Zone (RPZ) activity for 2007-2008.

356 Open Letter Consultation on the Innovation Funding Incentive and Registered Power Zone Schemes for Distribution Network Operators, Ofgem, 14th February 2007.

357 Review of Energy Market Frameworks in light of Climate Change Policies - Final Report, AEMC, 30 September 2009, p122.

358 Review of Energy Market Frameworks in light of Climate Change Policies, Response to Australian Energy Market Commission's Final Report, MCE, December 2009, p13.

9.4.3
DMIA assessment criteria

ETSA Utilities does not agree with the AER's decision not to alter the assessment criteria for the DMIA to specifically recognise the likelihood that a project or program may fail to deliver the intended outcome, or fail to deliver the outcome in a timely manner.

In its consideration of this matter, the AER stated "the assessment criteria do not consider the probability of the project's successful reduction of demand or deferral of expenditure" and "ETSA Utilities' concerns regarding the ex–post assessment of projects under the DMIA are addressed by the DMIS as it currently stands." [359]

The DMIA criteria in section 3.1.3 of the DMIS decision includes the following provision:

> *"3. Demand management projects or programs may be innovative, and designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts."* [360]

ETSA Utilities considers that with the judicious application of hindsight, in an ex-post review, the AER could potentially disallow projects or programs on the basis that they were not "potentially efficient ... mechanisms". ETSA Utilities therefore reiterates its view that there is inadequate consideration in the AER's assessment process that a project or program may fail to deliver its intended outcome.

This concern is echoed in a report commissioned by the AEMC for its recent Review of Energy Market Frameworks in light of Climate Change Policies.[361] In reviewing the design options for an Australian innovation funding scheme, NERA commented: "*The disadvantages include: ...*

- *uncertainty about funding (particularly if there is scope in the scheme design for a third party to retrospectively disallow funding for a project that it considers did not satisfy the scheme criteria);"* [362]

9.4.4
Foregone revenue provisions of the DMIS

With regard to the coverage of Part B (foregone revenues) of the DMIS, ETSA Utilities does not agree with the arguments advanced by the AER in support of restricting the recovery of foregone revenues to those projects approved under Part A.

In the Framework and approach paper, the AER has stated that it:

> *"has taken into account the impact of the new WAPC form of control on ETSA Utilities' incentives to adopt or implement efficient non-network alternatives, vis-à-vis its current form of control. In recognition of the reduction in revenues that will result from a reduction in the quantity of electricity sold, and the associated disincentives to implement demand management, the AER has included in part B of the DMIS a foregone revenue mechanism modelled loosely on that in the New South Wales D-factor."* [363]

ETSA Utilities contends for a DNSP under a WAPC, the loss of sales is a disincentive regardless of whether a demand management project is approved under Part A or not.

Also, loss of sales associated with demand management projects is not a disincentive for a DNSP with a revenue cap. Accordingly, unless Part B is extended to cover all demand management projects not already incorporated in the sales, demand and expenditure forecasts, the barrier for ETSA Utilities to implement such demand management projects, outside of the scope of Part A, is significantly higher than a DNSP with a revenue cap.

In addition, the AER's contention that the primary sources of recovery of demand management expenditure are through the capital and operating allowances of the determination, fails to recognise that:

- the rate of return on capital expenditure projects is established for projects having a low risk profile, equivalent to the "tried and true" network augmentation alternative. Demand management alternatives invariably have a higher risk profile, associated with both their cost structure and the potential that they may not deliver sufficient demand reduction, or may not deliver that reduction in a timely manner;
- in many instances demand management projects will involve a direct trade-off, as the deferral of capital expenditure will generally require additional operating expenditure to be incurred. The regulatory incentives which the AER has set up for capital and operating expenditure are not equivalent; and
- the distributor does not have access to benefits accruing to other industry sectors such as transmission companies, generators and retailers.

359 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, pp384, 385.

360 Final Decision - Demand Management Incentive Scheme, Energex, Ergon Energy and ETSA Utilities, 2010–15, AER, October 2008, p5

361 Review of Energy Market Frameworks in light of Climate Change Policies - Final Report, AEMC, 30 September 2009.

362 An Innovation Funding Scheme for Network Businesses - A Report for the Australian Energy Market Commission, NERA Economic Consulting, 31 August 2009, p29.

363 AER, *Framework and approach Paper: ETSA Utilities 2010-15 – Final*, November 2008, p 95.

Moreover, the AER has made a decision to apply a STPIS, which would result in financial penalties if a demand management scheme were to fail to perform as expected, as such events are not excluded[364].

These factors, plus the likely community reaction to a demand management project which failed to deliver, all serve to increase the potential cost and add to the risk associated with demand management alternatives.

ETSA Utilities is committed to complying with its jurisdictional requirements and will continue to observe the requirements of the Regulatory Investment Test, but in doing so it notes the effect of limiting the recognition of foregone sales revenue will reduce the likelihood that demand management options will be financially viable, and therefore will not proceed. Accordingly, ETSA Utilities strongly advocates that Part B be extended to cover all demand management projects, which have not been incorporated in the sales, demand and expenditure forecasts.

A reason the AER gives for not extending Part B is that the DMIS provides ETSA Utilities with other compensation options should ETSA Utilities seek to undertake new trials during the next regulatory control period.[365] The AER notes that ETSA Utilities can submit such trials for DMIA expenditure funding and be eligible for compensation under Part B upon their successful implementation, and that the foregone revenue component of the DMIS is uncapped.[366] However, the reasoning of the AER does not deal with the circumstance in which the Part A cap has been met.

The function of Part A is the approval of projects, with the total amount of expenditure to be approved over the five year regulatory period not to exceed $3 million. It is not clear, under the terms of the DMIS, that the scheme operates such that the AER can approve projects under Part A in circumstances where the cap has been met or exceeded. This operates as a clear disincentive to the implementation of demand management projects. At a minimum, the DMIS should be varied to make it clear that even where the Part A cap has been, or will be, exceeded, projects may still be approved under Part A of the DMIS for the purposes of recovering foregone revenue in Part B of the DMIS.

9.5

REVISED PROPOSAL

ETSA Utilities does not agree with the AER's analysis and conclusions in not accepting the proposed broadening of the application of Parts A and B of the DMIS in ETSA Utilities' Original Proposal. ETSA Utilities believes that its proposed broadening of the application of Parts A and B of the DMIS is consistent with the views of consumer groups that incentives should be such that demand management solutions should play a bigger role.

This was evident at the AER's public forum in Adelaide to discuss ETSA Utilities' Original Proposal, on 6 August 2009. A number of stakeholders raised concerns over the lack of incentive for effective demand management present in the AER's Draft Determination.

Accordingly, this Revised Proposal recommends:

- explicit statement in the DMIA assessment criteria that projects under DMIA would not be disallowed in an ex-post review, in the event that they do not achieve the intended demand reduction or do not achieve that demand reduction in a timely manner; and
- extension of the scope of Part B of the DMIS to permit the recovery of foregone revenue on demand management projects other than those approved under Part A of the scheme.

Additionally, in order to ensure that Part B of the DMIS applies to additional projects that meet the Part A criteria, the DMIS should be varied to make it clear that even where the Part A cap has been, or will be, exceeded, projects may still be approved under Part A of the DMIS for the purposes of recovering foregone revenue in Part B of the DMIS.

9.5.1 DMIA assessment criteria

In the Draft Determination, the AER has decided not to alter the assessment criteria for the DMIA to specifically recognise the likelihood that a project or program may fail to deliver the intended outcome or may fail to deliver the outcome in a timely manner.

For the reasons set out in section 9.4.3, ETSA Utilities does not accept the AER's assurance that because the success or otherwise of a scheme is not an assessment criterion, a project or program which did not perform as intended would not be precluded from approval in an ex-post review.

ETSA Utilities considers there is scope for the AER to disallow projects or programs that did not perform as intended, on the basis that they were not "potentially efficient ... mechanisms". ETSA Utilities therefore reiterates its view that there is inadequate consideration in the AER's assessment process that a project or program may fail to deliver its intended outcome.

364 Electricity distribution network service providers Service target performance incentive scheme, AER, May 2009, p12.

365 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 387.

366 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 387.

9.5.2
Recovery of foregone revenue

In its Draft Determination, the AER has proposed that the recovery of foregone revenue should be limited to those demand management projects approved under the DMIA.

The reduced sales volumes under a WAPC form of control, which accompany any demand reduction activity act as a significant disincentive to DNSPs in reducing demand, both for projects which are specifically targeted at reducing demand at a particular location and time, and those which have a broader effect.

ETSA Utilities agrees that approved innovation projects should be eligible for the recovery of foregone revenue. However, restricting the recovery to these projects alone is not appropriate. Section 9.4.4 sets out the reasons why ETSA Utilities does not believe the AER has given adequate consideration to overcoming impediments to the implementation of demand management.

ETSA Utilities reiterates the position put in the Original Proposal, that the DMIS Part B should be expanded to apply to any additional demand management project undertaken by ETSA Utilities in the next regulatory period that does not form part of this Revised Proposal, whether undertaken within the scope of the DMIS Part A or not.

As noted above, the Draft Determination provides that ETSA Utilities can submit new trials for DMIA expenditure funding, which were not part of its regulatory proposal, and be eligible for compensation under Part B upon their successful implementation, and that the foregone revenue component of the DMIS is uncapped.[367] However, it is not clear, under the terms of the DMIS, that the scheme operates such that the AER can approve projects under Part A in circumstances where the cap has been met or exceeded. Therefore, and at a minimum, the DMIS should be varied to make it clear that even where the Part A cap has been, or will be, exceeded, projects may still be approved under Part A of the DMIS for the purposes of recovering foregone revenue in Part B of the DMIS.

Revised Proposal

ETSA Utilities believes that in its Draft Determination, the AER has proposed a regime which will not encourage the development and implementation of demand management. The consequent low take up of demand management in the regulatory control period will not match community and stakeholder expectations.

Accordingly, in this Revised Proposal, ETSA Utilities advocates the following measures to broaden the scope of the AER's DMIS and provide a more appropriate environment to undertake demand management :

- *explicit statement in the DMIA assessment criteria that projects under DMIA would not be disallowed in an ex-post review, in the event that they do not achieve the intended demand reduction or do not achieve that demand reduction in a timely manner; and*
- *extension of the scope of Part B of the DMIS to permit the recovery of foregone revenue on demand management projects other than those approved under Part A of the scheme.*

Additionally, and at a minimum, the DMIS should be varied to make it clear that even where the Part A cap has been, or will be, exceeded, projects may still be approved under Part A of the DMIS for the purposes of recovering foregone revenue in Part B of the DMIS.

367 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 387.

10

We do everything in our power to deliver yours

Service standard framework

10

SERVICE STANDARD FRAMEWORK

In this chapter of the Revised Proposal, ETSA Utilities responds to the AER's Draft Determination on aspects of the service standard framework, and in particular on the implementation of the service target performance incentive scheme (STPIS).

10.1

RULE REQUIREMENTS

Under clause 6.6.2(1) of the Rules, the AER must develop and publish an incentive scheme(s) to provide incentives for DNSPs to maintain and improve performance. In accordance with this provision, the AER published a STPIS on 26 June 2008. The STPIS was most recently amended in November 2009 (the November 2009 STPIS).

Clause 6.6.2(b)(2) of the Rules provides that the AER must ensure that the service standards and service targets set by the STPIS do not put at risk the DNSP's ability to comply with relevant service standards and service targets, including average service standards and guaranteed service levels (GSLs), as specified in jurisdictional electricity legislation.

10.2

ETSA UTILITIES' ORIGINAL PROPOSAL

In its Original Proposal, ETSA Utilities proposed that the AER apply a STPIS based on:

- the reliability and customer service components of the STPIS guideline, utilising an s-factor as defined in the AER's amended STPIS;
- reliability performance measures of SAIDI and SAIFI for the feeder categories defined in the STPIS guideline;
- telephone grade of service (GOS) for the customer service measure;
- no GSL component (unless ESCOSA abolishes its existing GSL scheme);
- total gains or penalties from the scheme being capped at 5% of revenue (0.5% for customer service) as proposed in the amended STPIS;
- targets (reliability and customer service components) established using past performance, with appropriate adjustments, being the exclusion of Major Event Days (MED) determined by application of the Box-Cox method to normalise ETSA Utilities' SAIDI distribution, noting that the AER's consideration of this approach was 'Subject to adequate verification of the supporting data in ETSA Utilities' Original Proposal,...' [368];
- a modified s-bank mechanism; and
- an alternative reporting method[369].

10.3

THE AER'S DRAFT DETERMINATION

In its Draft Determination, the AER concluded with regard to ETSA Utilities' Original Proposal, PB's report and other submissions that:

- The SAIDI and SAIFI supply reliability parameters and the telephone answering parameters should be applied as per the Framework and approach paper [370].
- ETSA Utilities' proposal to cap total gains or penalties from the scheme at 5% of revenue was not consistent with the objectives of the STPIS or clause 6.6.2(b)(3) of the Rules. As a result, the AER will maintain the approach set out in the Framework and approach paper and apply a cap on overall revenue at risk of ±3%.
- A cap on revenue at risk of ±0.3% for the telephone response answering parameter will apply in accordance with clause 5.2(b) of the STPIS.
- The GSL component of the STPIS will not be applied to ETSA Utilities while the GSL scheme administered by ESCoSA remains in place.
- The Box-Cox transformation method will be applied to ETSA Utilities to set the MED boundary in the next regulatory control period.
- The approach proposed by ETSA Utilities to amend the s-bank mechanism does not satisfy the criteria set out in clause 6.6.2 of the Rules.
- It is appropriate that ETSA Utilities provide data and telephone GOS data to the AER, consistent with the definition set out in the STPIS.
- The approach proposed by ETSA Utilities to set performance targets based on four years of available data satisfies the criteria that the AER must consider in approving an alternative methodology under clause 3.2.1(c) of the STPIS.
- The performance targets proposed by ETSA Utilities in the next regulatory control period are consistent with clause 3.2.1(a)(1) of the STPIS.

10.4

ETSA UTILITIES' RESPONSE TO AER'S DRAFT DETERMINATION

In this Revised Proposal, ETSA Utilities has incorporated the majority of the AER's findings with respect to the application of the STPIS. However, ETSA Utilities' Revised Proposal differs from the AER's Draft Determination in relation to the matters set out in section 10.5 below.

368 AER, *Final Framework and approach paper ETSA Utilities 2010 - 2015*, November 2008, p 72.

369 ETSA Utilities advised in a letter to the AER dated 25 September 2009, that we would adopt the method specified in the STPIS to use average customer numbers to calculate SAIDI and SAIFI. Revised targets based on this methodology were provided in the letter. These targets were based on ETSA Utilities employing the local jurisdictional definition of planned and unplanned interruptions as provided in ETSA Utilities' Original Proposal section 10.5.3 page 216. **Note**: the STPIS does not define planned and unplanned interruptions.

370 AER, *Final Framework and approach paper ETSA Utilities 2010 - 2015*, November 2008, p 76.

10.5

DEVIATIONS FROM THE DRAFT DETERMINATION

10.5.1 Setting performance targets for the reliability of supply parameters

ETSA Utilities' Original Proposal

In its Original Proposal, ETSA Utilities provided indicative performance targets for the reliability of supply parameters based on its performance in the previous three years (ie for the period from 2005/06 to 2007/08). However, ETSA Utilities indicated that data on its performance in 2008/09 would be available in August 2009—before the AER issued its draft distribution determination. Therefore, ETSA Utilities proposed that the targets be determined on the basis of performance data for the four year period from 2005/06 to 2008/09.[371]

The AER's Draft Determination

In its Draft Determination, the AER proposed to accept ETSA Utilities' proposal and establish the performance targets on the basis of four years of data.[372]

ETSA Utilities' response to the AER's Draft Determination

Clause 6.12.1 of the Rules sets out a number of constituent decisions that must be made by the AER as part of each distribution determination. In relation to the STPIS, clause 6.12.1(9) of the Rules provides that, as part of each distribution determination, the AER must make a decision on how any applicable STPIS is to apply to the DNSP. Consistent with this provision, in its Draft Determination, the AER determined that the November 2009 STPIS will apply to ETSA Utilities for the next regulatory control period.[373]

Under clause 3.2.1(a) of the November 2009 STPIS, performance targets for the reliability of supply parameters must be based on average performance over the past five regulatory years. However, under clause 3.2.1(c), if data for the previous five regulatory years is not available, the AER may approve a performance target based on an alternative methodology or benchmark.

At the date of submission of the Original Proposal, ETSA Utilities did not have an appropriate data series of five years on which average performance could be determined.[374] On this basis, and consistent with clause 3.2.1(c) of the November 2009 STPIS, the AER concluded that the approach proposed by ETSA Utilities to set performance targets based on four years of available data satisfied the criteria the AER must consider in approving an alternative methodology under clause 3.2.1(c) of the STPIS.

ETSA Utilities has measured its reliability performance against its service standard obligations since 1999/2000 using manual reliability data. This measurement method continues for the current regulatory control period. From 1 July 2005, ESCOSA required ETSA Utilities to implement an Outage Management System (OMS) to incorporate the measurement of low voltage interruptions and to facilitate the automatic payment of reliability GSL payments. The reliability data produced by the OMS will be used to establish reliability service standard targets for the 2010–2015 regulatory control period.

OMS reliability data for the past five regulatory years will be available from 1 July 2010. In these circumstances, and consistent with clause 3.2.1(a) of the November 2009 STPIS, ETSA Utilities proposes that OMS data for the five years ending 30 June 2010 be used to set the reliability targets for the STPIS.

In this regard, ETSA Utilities notes that the use of the five years ending 30 June 2010 to set the reliability targets for the STPIS is consistent with ESCOSA's recent proposal to establish jurisdictional reliability targets using OMS data for the five year period from 2005/06 to 2009/10 (discussed below). ETSA Utilities considers that this alignment of the periods for setting the jurisdictional and STPIS targets is appropriate, as it will ensure that there will not be a disjoint (ie different baseline) between the two sets of targets.

In December 2008, ESCOSA issued its Final Decision on Electricity Service Standards for 2010 to 2015, under which it proposed to establish the reliability targets for the service standard framework using reliability data for the four year period from 2005/06 to 2008/09. However, in November 2009 ESCOSA requested stakeholders views on whether the jurisdictional service standards should be established on the basis of five years of OMS data (ie data for the period from 2005/06 to 2009/10).

371 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010-2015*, July 2009, p 213.

372 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 365.

373 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, p 366.

374 ETSA Utilities, ETSA Utilities Regulatory Proposal 2010 -2015, July 2009, p.207 –208. In the Original Proposal it was noted that ETSA Utilities had utilised manual reliability reporting processes for reporting against and establishing reliability targets. An Outage Management System, which was designed to enable the automatic payment of reliability GSLs and to accurately report on low voltage interruptions commenced on 1 July 2005. ETSA Utilities noted that it is not possible to apply any meaningful transformation on the manual data to make it comparable to the Outage Management System data, and therefore it was decided to establish the reliability targets for the next regulatory period on the average performance as reported by the Outage Management System for the period 1 July 2005 to 30 June 2009, and to ignore the prior manual data for the purposes of establishing new targets.

In its submission to ESCOSA [375], ETSA Utilities submitted that it is appropriate to set jurisdictional standards on the basis of five years of OMS data, as such an approach better reflects the average performance of the distribution system. On 15 December 2009, ESCoSA provided preliminary advice that they will favourably consider ETSA Utilities' submission.

If ESCOSA establishes its jurisdictional targets using five years of data, but the STPIS targets use only four years of data, there will be a disconnect between ETSA Utilities' jurisdictional service standards and the STPIS targets. As a result, the STPIS targets may be set below the jurisdictional targets, in which case ETSA Utilities will be rewarded under the STPIS for maintaining its reliability performance. Conversely, the STPIS targets may be set above the jurisdictional targets, in which case ETSA Utilities would be penalised under the STPIS for meeting the jurisdictional targets.

ETSA Utilities considers that both of the above outcomes are inappropriate. In this regard, ETSA Utilities notes that, in its Draft Determination, the AER indicated that "the STPIS performance targets would be established at or above the current SSF levels established by ESCOSA".[376] Such an approach would ensure that ETSA Utilities would neither be rewarded nor penalised for achieving the SSF (or jurisdictional service standards) targets.

For these reasons, ETSA Utilities considers that the STPIS reliability targets should be determined using the same period as that used to establish ESCOSA's jurisdictional targets. This is likely to be a period of five years.

ETSA Utilities acknowledges that five years of reliability data will not be available until 1 July 2010. As a result, the STPIS targets for 2010/11 could not be established until 30 September 2010 (ie after the commencement of the next regulatory control period). However, and in the event that ESCoSA confirms its preliminary position to set jurisdictional standards on the basis of five years of OMS data, to ensure that the most accurate data is utilised in setting the targets and that those targets best reflect the long term performance of the distribution network, ETSA Utilities considers it appropriate to delay setting the 2010/11 targets until five years of data is available.

Setting the 2010/11 targets at a later date will not affect service standards or reliability in the short term (ie from 1 July to 30 September 2010). This is because, ETSA Utilities' reliability management plans have been established to maintain reliability performance over the long term. As a result, ETSA Utilities is well placed to effectively manage the reliability of the distribution network in the absence of any STPIS targets. In the event that ESCoSA sets jurisdictional standards on the basis of four years of OMS data, the AER's approval of a alternative methodology based on four years will enable consistency between jurisdictional standard and the STPIS.

Revised Proposal
For the reasons stated in section 10.5.1, ETSA Utilities considers that the STPIS reliability targets should be determined using the same period as that used to establish ESCOSA's jurisdictional targets. This is likely to be a period of five years.

10.5.2 Exclusion of Major Event Days for measuring telephone response under the STPIS

In its Original Proposal, ETSA Utilities, as permitted by clause 5.4(a) of the STPIS, excluded MEDs from the data used to calculated the targets for telephone response performance. Consequently, the targets referred to in the AER's Draft Determination[377] exclude MED telephone response performance. The exclusion of these MEDs in the calculation of the telephone response target was recognised by PB in their Report[378].

Revised Proposal
ETSA Utilities' measures under the STPIS exclude major event days, as permitted by clause 5.4(a) of the STPIS.

375 South Australia Electricity Distribution Service Standard 2010 – 2015, Review of Regulatory Instruments, November 11 2009

376 AER, *South Australian Draft Distribution Determination 2010-11 to 2014-15*, p.349

377 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, 25 Nov 2009, Table 12.4, p 366.

378 PB Report "Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015" Chapter 7, clause 7.3.2, pp 174/209

11

We do everything in our power to deliver yours

Efficiency benefit sharing scheme

11

EFFICIENCY BENEFIT SHARING SCHEME

In this chapter of the Revised Proposal, ETSA Utilities:

- responds to the AER's Draft Determination in relation to the application of the Efficiency Benefit Sharing Scheme (EBSS) for the 2010–2015 regulatory control period; and
- calculates the appropriate transitionary carryover amount to be carried forward from the Efficiency Carryover Mechanism (ECM) established by the Essential Services Commission of South Australia (ESCoSA) for the 2005–2010 regulatory control period.

In this Revised Proposal ETSA Utilities has incorporated the AER's Draft Determination in relation to the EBSS insofar as the decision relates to the operating expenditure categories to be excluded from the operation of the EBSS for the 2010–2015 regulatory control period.

However, ETSA Utilities has not incorporated in this Revised Proposal the AER's approach to the transition of the ECM established by ESCoSA for the period 2005–2010 to the AER's EBSS. In particular, ETSA Utilities considers that, given the efficiency carryover arising from the 2005–2010 period is a negative amount after removal of uncontrollable cost items, no negative carryover amount should be included in the determination of the inputs to ETSA Utilities' distribution revenue, either immediately or on a deferred basis.

ETSA Utilities maintains its position that the Statement of Regulatory Intent issued by ESCoSA (ESCoSA SoRI) is incorrect and invalid to the extent it sought to include uncontrollable cost items and to apply a negative carryover amount arising during the regulatory period 2005–2010.

11.1

RULE REQUIREMENTS

In accordance with the National Electricity Rules (the Rules), ETSA Utilities described in the Original Proposal how the EBSS, developed and published by the AER under clause 6.5.8, will apply to ETSA Utilities for the 2010–2015 regulatory period.

As set out at section 11.1 of ETSA Utilities' Original Proposal, for the purpose of the 2005–2010 regulatory period ETSA Utilities was regulated by ESCoSA under the Electricity Pricing Order (EPO), the National Electricity Law (NEL), the National Electricity Code (the Code) and (on a transitional basis arising from the repeal of the Code) the National Electricity Rules which were in place prior to January 2008.

In relation to the 2005–2010 regulatory period, ESCoSA promulgated the ECM which was partly outlined in ESCoSA's 2005–2010 Electricity Distribution Pricing Determination for ETSA Utilities (EDPD) and then further elaborated on through the ESCoSA SoRI[379].

Clause 9.29.5(c) of the Rules provides that the AER will determine the transitionary carryover amount from the old scheme to the new Rules-based scheme and that it will do so consistently with the ESCoSA SoRI.

11.2

ETSA UTILITIES' ORIGINAL PROPOSAL

In its Original Proposal, ETSA Utilities proposed a number of uncontrollable cost categories to be excluded from the operation of the EBSS to apply to ETSA Utilities for the 2010–2015 regulatory period.[380]

As a result of there being a net negative carryover amount arising from the 2005–2010 regulatory period after removal of uncontrollable cost items and given that ETSA Utilities considered the ESCoSA SoRI to be incorrect or invalid to the extent that it allowed for the carryover of negative efficiency amounts, ETSA Utilities did not carryover any negative efficiency amount into the 2010–2015 regulatory period, either immediately or on a deferred basis.[381]

11.3

THE AER'S DRAFT DETERMINATION

In accordance with clause 6.12.1(9) of the Rules, the AER has determined that the EBSS published by the AER in June 2008 should apply to ETSA Utilities for the 2010–2015 regulatory control period.

The AER's Draft Determination was to exclude the following operating expenditure categories from the operation of the EBSS to apply to ETSA Utilities for the 2010–2015 regulatory period:[382]

- debt raising costs;
- insurance and self insurance costs;
- superannuation costs for defined benefits and retirement schemes;
- the demand management innovation allowance (DMIA); and
- 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 relevant principles expressed in clause 6.6.1(j) of the NER and the EBSS.

These costs are in addition to the other costs excluded by the EBSS, including non-network alternatives and recognised pass through events.

The AER noted that under clause 9.29.5(c) of the Rules, the AER's application of the EBSS to ETSA Utilities for the period 2005–2010 must be consistent with the ESCoSA SoRI.

The AER determined to allow a negative operating expenditure carryover accrued in respect of the current regulatory control period 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 operating expenditure category under the EBSS.[383]

379 ESCoSA, Statement of Regulatory Intent (23 March, 2007).

380 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p. 222.

381 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p. 227.

382 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 378.

383 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, p. 378.

11.4

ETSA UTILITIES' RESPONSE TO AER'S DRAFT DETERMINATION

11.4.1
For EBSS applying 2010–2015

In this Revised Proposal ETSA Utilities has incorporated the AER's Draft Determination in relation to the EBSS insofar as the decision relates to the operating expenditure categories to be excluded from the operation of the EBSS for the 2010–2015 regulatory control period.

11.4.2
ECM applying 2005–2010

This section responds to the AER's Draft Determination as it relates to the application of the ECM that applied in the regulatory period 2005–2010.

Application of the ECM arising from 2005–2010

For the reasons outlined below, ETSA Utilities considers the relevant amounts for the purpose of the ESCoSA ECM are the following:[384]

- in relation to the efficiency carryover arising from the 2005–2010 period, the total of the capital and operating expenditure 'out turn' value is -$2.748m, after removal of uncontrollable superannuation costs of -$12.623m and a minor adjustment to exclude sponsorship costs from actual expenditure;[385] and
- any negative amount to be carried over into the 2010–2015 regulatory period is to be set to zero as paragraph 4 of the ESCoSA SoRI is incorrect or invalid.

The 'out turn' capital and operating expenditure values based on actuals are calculated as follows:

Table 11.1: Table of out turn capital expenditure

Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10
	0.892	0.892	0.892	0.892	0.892				
		3.276	3.276	3.276	3.276	3.276			
			3.852	3.852	3.852	3.852	3.852		
				0.375	0.375	0.375	0.375	0.375	
					0	0	0	0	0
					8.395	7.503	4.226	0.375	0

Real, June 2010 $Million

Table 11.2: Table of out turn operating expenditure[1]

Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10
	15.861	15.861	15.861	15.861	15.861				
		5.263	5.263	5.263	5.263	5.263			
			(19.705)	(19.705)	(19.705)	(19.705)	(19.705)		
				(0.788)	(0.788)	(0.788)	(0.788)	(0.788)	
					0.003	0.003	0.003	0.003	0.003
					0.633	(15.228)	(20.491)	(0.786)	0.003

Real, June 2010 $Million

Note:

(1) Consistent with the correspondence on the Framework & approach paper, ETSA Utilities has excluded the DM allowance in the EDPD calculations. These amounts were a once-off allowance and there cannot be any on-going incentives in respect of these amounts in the new regulatory period.

384 The 2005–2010 outturn values shown are based on actual costs for the 2005–2010 period, and to that extent, differ from those amounts in ETSA Utilities' Original Proposal, which were based on forecast costs for the regulatory year 2009.

385 This was necessary as ESCoSA provided no allowance for this cost in its determination of operating expenditure allowance in the ESCoSA 2005–2010 EDPD.

Transitional arrangements for carryover from 2005–2010

ETSA Utilities maintains the position it put forward in its Original Proposal in relation to the arrangements regarding its transition from ESCoSA's ECM to the AER's EBSS. In particular, the aspects of the ESCoSA SoRI which sought to include uncontrollable cost items within the scheme and which sought to apply a negative carryover amount, either immediately or on a deferred basis, are considered by ETSA Utilities to be incorrect or invalid.

ETSA Utilities remains of the view that:

- the ESCoSA SoRI should be read down to exclude the inclusion of uncontrollable cost items when calculating the carryover; and
- any negative carryover amount which might result should be disregarded.[386]

This can be achieved by:

- first, a contextual reading down of the entire ESCoSA SoRI such that the AER's application of the EBSS is to be consistent with the ESCoSA SoRI only to the extent that the ESCoSA SoRI was supported by the Code and the EPO; and
- secondly, by simply taking the ESCoSA SoRI and striking out the incorrect or invalid paragraph 4.

In this regard, ETSA Utilities considers that the AER has not given proper consideration to the arguments raised by ETSA Utilities in its Original Proposal in relation to the incorrect or invalid nature of the ESCoSA SoRI insofar as it relates to the treatment of uncontrollable cost items and negative efficiency carryovers.

Further discussion of ETSA Utilities' Original Proposal

ETSA Utilities' consideration of the transitional carryover amount was set out in section 11.3 of its Original Proposal. This detailed consideration of the transitional carryover amount included an historical background to the development of efficiency carryover schemes and an outline of the relevant efficiency scheme provisions of the regulatory instruments under which the ESCoSA ECM was formulated, i.e. the Code and the EPO. Further, ETSA Utilities brought to the attention of the AER recent regulatory developments which demonstrated that the inclusion of uncontrollable costs and the contemplation of negative efficiency carryover amounts in the ESCoSA SoRI were premature and inappropriate, and an invalid exercise of ESCoSA's regulatory powers at the time of the publication of the ESCoSA SoRI.

As discussed in ETSA Utilities' Original Proposal, while incentive regulation has evolved to operate symmetrically in that both efficiencies and inefficiencies are taken into consideration by a regulator when formulating an incentive mechanism, this regulatory development is reasonably recent. The initial concept of incentive regulation was limited to providing businesses with a positive incentive to reveal efficiencies by allowing the business to retain efficiency benefits for a full five years before they were passed on to customers. Accordingly, with incentive mechanisms being concerned only with efficiency gains, the language of the regulatory instruments which empowered the regulator to provide these rewards at that time was couched only in positive terms. As pointed out by ETSA Utilities in its Original Proposal, the regulatory instruments which ESCoSA was obligated to apply when formulating its efficiency mechanism for ETSA Utilities in the 2005–2010 period—the Code and the EPO—date from this time. Consequently, the language of the relevant provisions in both of these regulatory instruments is exclusively and wholly positive with no 'mirror' negative concepts.[387]

In its Original Proposal, ETSA Utilities submitted that, due to the absence of negative language in the NEC and the EPO, ESCoSA's published intention to carry forward any negative amount arising from the 2005–2010 period into the 2010–2015 period was not supported by legislative authority.[388] In addition, ETSA Utilities again raised a concern it had expressed when ESCoSA initially introduced the potential for a negative carryover in its incentive mechanism in April 2003, that being that the scheme as proposed by ESCoSA could result in a significant negative carryover resulting not from inefficiency but from adverse movements in uncontrollable costs.

386 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010—2015*, July 2009, p. 227.

387 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, pp. 224-225.

388 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p. 223

To support its position, ETSA Utilities identified in its Original Proposal a number of recent regulatory developments which demonstrated that ESCoSA's attempt to include uncontrollable cost items and foreshadow the imposition of a negative carryover at that time was both a premature regulatory development and inappropriate. ETSA Utilities identified four important developments:

(a) First, in December 2008, the Victorian Essential Services Appeal Panel (the Panel) considered the application of a negative carryover in relation to the efficiency mechanism in Envestra Albury's gas access arrangement and concluded that, as the language of the relevant provisions only contemplated positive efficiency gains, the regulator did not have the power or discretion to enable the inclusion of a negative efficiency mechanism.[389]

b) Second, regulatory determinations in a range of jurisdictions have excluded uncontrollable costs from efficiency schemes, including the AER's own EBSS determination. This line of regulatory precedent includes the Panel's decision in relation to AGL Electricity's efficiency benefit scheme for its 2001–2005 price determination, where it was determined that any 'rule of thumb' measurement of costs must, in fact, be an accurate indicator of efficiency.[390]

(c) Third, only with appropriate reforms to the regulatory arrangements in place, was it possible to replace the language in the Code and the gas equivalent with new provisions which explicitly provide for negative cost carryovers for genuine inefficiencies as well as the rewards for efficiency gains.

(d) Fourth, although ETSA Utilities has succeeded in making efficiency gains on controllable cost items in the 2005–2010 period, it has also suffered from adverse movements in certain cost categories during the period which are outside its control, for example, with respect to defined benefit superannuation costs. Accordingly, if the ESCoSA SoRI were to apply on its own terms, the effect would be to significantly 'punish' the business for those adverse movements beyond its control for a further series of years.

For the reasons outlined above and as stated in its Original Proposal, ETSA Utilities considers that, while the AER is obliged under clause 9.29.5(c) of the Rules to apply its determination in a manner consistent with the ESCoSA SoRI , the ESCoSA SoRI should be read in the context of the instrument that actually provides for a pricing determination in respect of ETSA Utilities to allow a mechanism for the benefits of efficiency gains to be shared. Seen in this context, the ESCoSA SoRI can only apply to this limited extent and the additional intentions of ESCoSA which were not (at the time) supported by legislative authority must be disregarded and taken as not forming part of the administrative act of ESCoSA.

Conclusion

ETSA Utilities does not consider that the AER has in its Draft Determination appropriately considered or adequately addressed ETSA Utilities' submissions in relation to the treatment of negative efficiency carryovers arising from the transition from ESCoSA's ECM to the AER's EBSS. In particular, the AER has not addressed ETSA Utilities' submission that ESCoSA's SoRI is incorrect or invalid insofar as it provided for the inclusion of uncontrollable cost items and sought to apply a negative carryover either on an immediate or deferred basis.[391]

The AER's Draft Determination does note ETSA Utilities' arguments in relation to whether the ESCoSA SoRI was a valid exercise of power in relation to the carryover of a negative amount.

However, ETSA Utilities submits that merely noting such a discussion does not constitute adequate consideration of the arguments raised in that discussion.

As a consequence of the AER's approach to this issue in its Draft Determination, it is difficult for ETSA Utilities to respond in a detailed way. Nonetheless, ETSA Utilities maintains its submission that the correct treatment of the transition to the 2010–2015 regulatory period is for the AER to:

- exclude the inclusion of uncontrollable cost items arising in the 2005–2010 period from the carryover amount; and
- disregard any negative carryover amount for the 2010–2015 period which results from costs arising in the 2005–2010 period.[392]

389 *Albury Gas Company (Ltd) v Essential Services Commission E2/2008* (11 November 2008), [178]

390 Statement of Reasons for Decision by Appeal Panel Under Regulation 15 of the Office of the Regulator-General (Appeals) Regulation 1996 in relation to the Electricity Distribution Price Determination 2001–2005, p.9.

391 ETSA Utilities, ETSA Utilities Regulatory Proposal 2010–2015, July 2009, p. 227

392 ETSA Utilities, ETSA Utilities Regulatory Proposal 2010–2015, July 2009, p. 227

11.5

REVISED PROPOSAL

In this Revised Proposal ETSA Utilities has incorporated the AER's Draft Determination in relation to the EBSS insofar as the decision relates to the operating expenditure categories to be excluded from the operation of the EBSS for the 2010–2015 regulatory control period.

However, ETSA Utilities does not accept the AER's approach to the transition from the ESCoSA ECM to the AER's EBSS. In particular, ETSA Utilities considers that given the efficiency carryover from the 2005–2010 period is a negative amount after removal of uncontrollable cost items, no negative carryover amount should be included in the determination of the inputs to ETSA Utilities' distribution revenue, either immediately or on a deferred basis.

The ESCoSA SoRI must be read down to remove that part of it which subsequent appeals have demonstrated was not supported by the NEC and the EPO at the time. The AER in its Draft Determination noted but did not appropriately consider the line of reasoning put forward by ETSA Utilities in its Original Proposal.

ETSA Utilities maintains its position that the ESCoSA SoRI is incorrect or invalid to the extent it sought to include uncontrollable cost items and to apply a negative carryover amount arising during the 2005–2010 regulatory period.

12

We do everything in our power to deliver yours

Regulated asset base

12

REGULATED ASSET BASE

In this chapter of the Revised Proposal, ETSA Utilities presents the updated calculations for its regulatory asset base (RAB), comprising system and non-system assets utilised in the provision of standard control services.

The revision to ETSA Utilities' RAB is in response to matters raised by the AER. Specifically this incorporates:

- the impact of changes to the opening RAB; and
- the impact of changes to forecast capital expenditure (chapter 6).

The methodology applied is in accordance with the National Electricity Rules (the Rules) and utilises the AER's Roll Forward and Post-Tax Revenue Models except to the extent that section 18(4) of the *National Electricity (South Australia) Act 1996* requires the provisions of the Electricity Pricing Order (EPO) to be given effect.

The completed standard control services Roll Forward Model (RFM) and standard control services Post-Tax Revenue Model (PTRM) are provided as Attachments H.1 and K.1 respectively to this Proposal.

The completed alternative control services RFM and alternative control services PTRM are provided as Attachments H.2 and K.2 respectively to this Proposal.

12.1

RULE REQUIREMENTS

The Rules at clause 6.5.1 describe the nature of the RAB and methodology to be used to determine the opening RAB. Schedule 6.1.3(10) requires a building block proposal to contain a completed PTRM and RFM.

The methodology adopted in rolling forward the RAB to 30 June 2015 is consistent with the Rules (as modified or supplemented by relevant provisions of the EPO) and the AER's RFM and PTRM.

12.2

ETSA UTILITIES' ORIGINAL PROPOSAL

The Original Proposal rolled forward the RAB to 2015 in accordance with the National Electricity Rules and using the AER's RFM and PTRM. In addition, to give effect to the requirements of the EPO, the Original Proposal included adjustments to the RAB for the valuation of easements and the correction of a modelling error.

In its Original Proposal, ETSA Utilities:

- determined the RAB value at 1 July 2005 by asset class ($2,466.255 million in December 2004 dollars);
- determined the roll forward of the RAB value from 1 July 2005 to 30 June 2010 ($3,011.0 million in nominal dollars); and
- determined the roll forward of the RAB value from 1 July 2010 to 30 June 2015 ($4,912.6 million in nominal dollars).

12.3

THE AER'S DRAFT DETERMINATION AND RESPONSE

The AER has accepted ETSA Utilities' proposed opening RAB, except for adjustments to the RAB for the valuation of easements and the correction of a modelling error. In addition, the AER has reclassified certain metering services as alternative control services, which has reduced the RAB for standard control services by $80.5 million.

ETSA Utilities has not incorporated the AER's draft findings for the roll forward of the RAB to 2010 in this Revised Proposal, with respect to:

- the valuation of easements (refer 12.3.1 below); and
- ESCOSA's treatment of capital contributions (refer 12.3.2 below).

The roll forward for the Revised Proposal to 1 July 2010 incorporates the actual capital expenditure for 2008-09, as determined by the AER in the Draft Determination. The roll forward to 1 July 2010 also incorporates:

- The previously determined capital expenditure allowance by ESCOSA for 2009/10 as the forecast for that year. This is consistent with the position taken by ETSA Utilities in its Original Proposal, and it is considered to be the most appropriate forecast for roll forward as it ensures consistency with ESCOSA's ECM calculation for the current regulatory period. The difference between this amount and the actual amount will be reflected in the RAB roll forward for 2015-20.
- The most recent forecast CPI for 2009/10, based on Actual CPI to September 2009 plus forecast CPI as per the Reserve Bank of Australia's Statement of Monetary Policy, released November 2009.

ETSA Utilities' roll forward of the RAB to 2015 also reflects the amended capital expenditure allowance in this Revised Proposal (chapter 6).

In this Revised Proposal, ETSA Utilities acknowledges and accepts the AER's decision to determine the opening RAB for the 2015–20 regulatory control period using actual depreciation[393].

393 AER, Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15, 25 Nov 2009, p 72.

12.3.1
RAB at 1 July 2010—valuation of easements

AER Adjustment of Opening RAB in the Roll Forward Model

The AER's Draft Determination did not accept ETSA Utilities' Original Proposal for the valuation of easements and RAB modelling adjustment.

In adjusting the RFM to reflect this decision, the AER deducted ETSA Utilities' proposed adjustments of $116.2 million and $16.3 million from the opening RAB value in the RFM respectively.

However, 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. 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)[394] 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.

ETSA Utilities will seek to further engage with the AER on this matter in their review of the underlying models that underpin this Revised Proposal.

Summary of ETSA Utilities' position

ETSA Utilities disagrees with the AER's Draft Determination concerning the valuation of easements used by ETSA Utilities to provide prescribed distribution services within the terms of clause 7.3(b)(iv) of the EPO both as to:

- the AER's Draft Determination not to increase the opening RAB to account for the valuation of those easements; and
- the reasons relied upon by the AER to reach that Draft Determination.

ETSA Utilities, for the reasons detailed below, maintains its view that a proper consideration of the submission made by ETSA Utilities contained in Attachment I.1 to its Original Proposal entitled 'Adjustment of the Opening RAB for the Valuation of Easements and the Correction of a Modelling Error' (Submission for Adjustment of the Opening RAB)[395] supports the inclusion of an amount in the RAB representing the value of easements.

It is ETSA Utilities' position that, in order to discharge the function conferred on the AER by clause 7.3(b)(iv) of the EPO, the AER should consider afresh the materials put by ETSA Utilities in its Submission for Adjustment of the Opening RAB for the valuation of easements, and, on the basis of the materials therein, increase the opening RAB to the extent identified in paragraph 15.1 of Part A of ETSA Utilities' Submission.

Response to Grounds for the Draft Determination

ETSA Utilities considers that the AER's grounds for its Draft Determination in respect of the valuation of easements have been affected by three fundamental errors, being:

- a failure 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;
- 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,

with the result that 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*.

394 AER, Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15, 25 Nov 2009, p 73.

395 ETSA Utilities, ETSA Utilities Regulatory Proposal 2010–2015, July 2009, Attachment I.1.

ETSA Utilities further states that these fundamental errors are manifested in the following aspects of the Draft Determination:

- the AER did not take account of the errors made by ESCoSA in its 2005–2010 Price Determination as identified by ETSA Utilities in its application for a review of the 2005–2010 Distribution Price Determination (as supplied to the AER by ETSA Utilities in its Original Proposal) and Section 6 of ETSA Utilities' Submission for Adjustment to the Opening RAB to the AER;
- the AER did not take account of events which have occurred since the decision of ESCoSA in respect of the 2005–2010 Price Determination, as detailed in Section 2.4 of the Submission for Adjustment to the Opening RAB;
- the AER has précised aspects of ESCoSA's 2005–2010 Price Determination process in respect of the valuation of easements as an apparent substitute for a direct analysis of ETSA Utilities' Submission for Adjustment to the Opening RAB which has led to:
  - the AER failing to directly engage with ETSA Utilities with respect to its application to the AER;
  - the AER treating the process by which ESCoSA engaged with ETSA Utilities in respect of clause 7.2(e)(iv) of the EPO as sufficient for the purposes of the AER discharging its functions under clause 7.3(b)(iv) of the EPO; and
  - the AER not making the decision required to be made by the AER under clause 7.3(b)(iv) of the EPO;

- the AER did not take account of the regulatory commitment (that is contained in clause 7.3 of the EPO) for a proper consideration of the value of easements as identified by ETSA Utilities in paragraph 1.4 of its Submission for Adjustment to the Opening RAB to ensure that there is a proper RAB for determining distribution pricing for 2010–2015 ;
- the AER did not act consistently with:
  - its own approach with respect to the ElectraNet transmission easements (which originally had an 'allowance' derived in the same manner as the allowance for distribution network easements in Schedule 9 of the EPO) where the AER recognised that, in relation to the compensation paid for those easements, indexed historic costs was the appropriate valuation methodology; and
  - the approach of the Australian Competition Tribunal in respect of acquisition costs for transmission network easements where the Tribunal determined that indexedhistoric costs of both compensation for and acquisition of the easements was the appropriate method of valuation,

  given that the $6 million 'allowance' in Schedule 9 of the EPO did not reflect an indexed historic cost of any aspects of the distribution network easements; and

- the AER did not take account of the first hand sworn evidence from Mr Stevens as to the source of the $6 million allowance for distribution network easements (which is described in paragraphs 4.1 and 4.2 of Part A of the Submission for Adjustment to the Opening RAB) that clearly establishes that the allowance could not be characterised as a valuation of those easements on any basis or as a calculation of their indexed historical costs.

Errors of the AER

ETSA Utilities provides further particulars of the AER's errors in support of its disagreement with its Draft Determination on the valuation of easements as follows:

- The AER characterises ETSA Utilities' application in its Submission for Adjustment to the Opening RAB to the AER as an application for a re-valuation of the easements. In fact, ETSA Utilities' application is and has been consistently expressed to be, an application for the undertaking of a valuation of the easements;
- The AER has not reconciled the differences between the application made by ETSA Utilities to ESCoSA for the 2005–2010 Price Determination in respect of the valuation of easements and the application made by ETSA Utilities to the AER in respect of the valuation of easements to the 2010–2015 Distribution Determination;
- The AER has not responded to ETSA Utilities' Submission for Adjustment to the Opening RAB concerning the errors made by ESCoSA in relation to the valuation of easements for the 2005–2010 Price Determination as identified in Section 6 of ETSA Utilities' Submission for Adjustment to the Opening RAB to the AER;
- The AER made material errors in its recitation and analysis of the context for and the conduct of the 2005–2010 Price Determination in respect of the valuation of easements, the effect and context of the EPO and the respective roles of ESCoSA and the Treasurer in respect of the creation of the EPO;
- The AER did not acknowledge the primacy of section 18 of the *National Electricity (South Australia) Act 1996* over the NER (being an absolute consequence of the relationship between the *National Electricity (South Australia) Act 1996* and the NER[396]), which has led the AER into error in not implementing the directive to the AER contained in clause 7.3(b)(iv) of the EPO. Whilst the AER stated that it would undertake the process referred to in clause 7.3(b)(iv), it has done so expressly subject to the caveat that the continued operation of clause 7.3 of the EPO is 'not clear' given the existence of clause 6.2.1(c)(1) of the NER and that as a result it describes its obligation as follows:

  '*...the AER considers it may have to give regard to clause 7.3 of the EPO and review the value of ETSA Utilities' easements*'

396 In this regard see also relevant extracts from Hansard associated with National Electricity (South Australia) (National Electricity Law—Miscellaneous Amendments) Amendment Bill, which provide: 'The national framework also maintains existing obligations arising from the South Australian Electricity Pricing Order. These obligations formed part of the foundation for the privatisation of the electricity distribution network in South Australia. The recognition of these arrangements ensures that, in accordance with the terms of the Electricity Pricing Order, the regulatory guidance established as part of the privatisation process is continued'; and 'New Part 6 will facilitate the transfer of the economic regulation of electricity distribution to the Australian Energy Regulator under South Australian law. Under these provi-sions, ESCoSA will continue to administer the 2005–2010 Electricity Distribution Price Determination made in April 2005 and the AER will undertake responsibility to make future price determinations, subject to certain require-ments set out in new section 18(5) and to the provisions of the relevant South Australian Pricing Order' (emphasis added).

- The grounds on which the AER distinguished the decision of the Australian Competition Tribunal with respect to the valuation of the ElectraNet transmission easements was affected by errors in that:
  - the AER limited the applicability of the Tribunal's decision to circumstances where representations were made by the South Australian Government to bidders for the ElectraNet business when, in fact, those representations were the basis for the creation of clause 11.6.13(b) of the NER, which then provided a basis for ElectraNet to press for the valuation of the easements used in the transmission network – viz the Tribunal decision assumed the existence of clause 11.6.13(b) of the NER, and made a decision as to its consequences;
  - 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; and
  - the AER did not acknowledge the substantial direct evidence as to the existence of representations to bidders by the South Australian Government as detailed in paragraphs 6.8 to 6.14 of ETSA Utilities' Submission for Adjustment to the Opening RAB being evidence of a significantly high probative value as compared with an untested statement by the South Australian Government to ESCoSA that it could not find evidence of representations;

- The EPO recognised the complexity and difficulty of undertaking a valuation of the distribution network easements by making provision in clause 7.2 for the valuation of the easements for the 2005–2010 Price Determination and then again, in clause 7.3 for the valuation of those easements for the 2010–2015 distribution pricing. In fact, the evidence presented by ETSA Utilities to the AER in the Submission for Adjustment to the Opening RAB is a substantial development of the data set provided to ESCoSA and reflects considerable additional research undertaken between 2007 and 2009 to recover the historical records concerning the easements, and to extract and analyse the indexed historic acquisition and compensation costs for all the categories of distribution network easements identified in the Submission for Adjustment to the Opening RAB. That additional research and data collection also took into account the changes in the regulatory position over that period which saw, initially, a focus on the deprival value for assets to be included in a regulatory asset base which then changed to a focus on indexed historic costs. That change necessitated a different approach to the data set prepared by ETSA Utilities for the Submission for Adjustment to the Opening RAB to the AER as compared to the data presented to ESCoSA for the 2005 opening RAB;
- On the issue of historical costs of the distribution network easements, the AER considered that 'the oldest valuation of the ETSA Utilities easements' was the '$6 million determined by the South Australian Government'. This $6 million amount was determined by the South Australian Government for inclusion in the asset base in the EPO in October 1999. This cannot represent an older valuation than the MFS 1996 Report, in the same way as the Australian Competition Tribunal considered that the 1997 MFS Report as to the value of the transmission network easements was the appropriate oldest valuation rather than the amount attributed to those transmission easements in the EPO in October 1999;
- The AER made a connection between the '$6 million value [sic] of easements determined by ESCoSA', 'the value [sic] used by the South Australian Government' and a process which 'established a fair market value of the business as a whole'. As the ESCoSA decision post-dated the privatisation of ETSA Utilities, it could not have played any role with respect to the setting of a fair market value of the business as a whole. In so far as the allowance made for easements by the South Australian Government in the EPO set a fair market value, then it was not acknowledged by the AER that:
  - the fair market value of ETSA Utilities greatly exceeded the RAB of the assets as set in the EPO as indexed to the time of privatisation; and
  - the EPO expressly created the expectation in the minds of a purchaser of the ETSA Utilities business that the valuation of easements would be considered at a later time without the need to correspondingly reduce the value of any other assets, see clauses 7.2 and 7.3 of the EPO.

In these circumstances, there can be no foundation for the conclusion of the AER that valuing the easements as sought by ETSA Utilities '...will require a compensating adjustment to [the value of] other asset classes'. Not only is there no basis in the NER or the EPO for an adjustment of the value of any of the other assets which have been properly valued in the EPO, but there is no basis for suggesting such an adjustment in any event;

- The AER did not acknowledge or implement the desirability for regulatory consistency as detailed in paragraphs 7.4 and 7.5 of the ETSA Utilities Submission for Adjustment to the Opening RAB; and
- The AER, as a result of using the 2005–2010 ESCoSA Price Determination process as a proxy for the application of clause 7.3(b)(iv) did not respond to or otherwise engage with ETSA Utilities as to ETSA Utilities' assertion that the position of ETSA Utilities and ElectraNet was indistinguishable in relation to the treatment of the valuation of easements as identified in Table 1 of its Submission for Adjustment to the Opening RAB.

Consistency of regulatory decisions

ETSA Utilities re-iterates what it said in paragraphs 7.4 and 7.5 of the Submission for Adjustment to the Opening RAB:

7.4 *Against that background, ETSA Utilities also recognises the strong policy grounds in favour of consistency in regulatory decision making as referred to in paragraph 200 of the ACT ElectraNet decision. Accordingly, whilst it did so in the 2005 Price Determination, ETSA Utilities no longer seeks deprival value of $224.45 million for the easements. Instead, in this Submission and in light of the AER/ACT determination in relation to ElectraNet, ETSA Utilities contends that the easements should be brought to account on the basis of their indexed historic costs.*

7.5 *That desire for consistency in regulatory decision making, in ETSA Utilities' opinion, also requires the AER to approach the 2010 Price Determination in a manner that is consistent with the ACT ElectraNet decision.*

Specifically, the AER should, consistent with the South Australian jurisdictional decision manifested by clause 7.3(b)(iv) of the EPO and the decisions of the AER and ACT in respect of the valuation of transmission easements for ElectraNet's Price Determination, value the distribution network easements existing as at 1 July 1999 at their indexed historical cost and adjust the ETSA Utilities RAB accordingly.

Revised Proposal

For the reasons set out in the Original and this Revised Proposal, ETSA Utilities proposes an increase to the Opening RAB as at 1 July 2005 with respect to easements of $116,200,380 (being $123,466,380 less the original allowance of $6 million indexed to 1 July 2005).

12.3.2 RAB at 1 July 2010—ESCOSA'S treatment of capital contributions

ETSA Utilities disagrees with the AER's Draft Determination regarding the adjustment made by ESCoSA as at 1 July 2005 for customer contributions from the ETSA Utilities fixed asset base as at 1 July 1999.

Clause 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, there was no basis for the deduction made by ESCoSA for the 2005–2010 Price Determination in clause 7.2 of the EPO. It was simply an error on the part of ESCoSA.

Not only is the correction of the error necessary for the purposes of regulatory consistency with the requirements of the EPO and the statutory mandate contained in the Electricity Act that ESCoSA, and now the AER, give effect to the EPO, 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.

In these circumstances, ETSA Utilities' position remains that there is a compelling basis for the AER to correct the error made by ESCoSA.

In respect of the suggestion that the inability of the AER to rely upon adjustments previously made by ESCoSA would require the AER to reconsider all previous adjustments made by ESCoSA is unfounded. 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.

Here, there is more than sufficient evidence to rebut the presumption of regularity on the part of the discharge by ESCoSA of its functions with respect to the adjustment of the fixed asset base but, 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.

Revised Proposal

For the reasons set out in the Original and this Revised Proposal, ETSA Utilities proposes an increase to the Opening RAB as at 1 July 2005 of $16,329,000, to correct for the erroneous adjustment made by ESCoSA in determining the opening asset base at 1 July 1999.

12.4

REVISED PROPOSAL

ETSA Utilities has calculated a revised RAB forecast for the next regulatory control period. This calculation uses the AER's RFM and PTRM and applies the same methodology as in the Original Proposal. It incorporates the changes to the valuation of easements, ESCOSA's treatment of capital contributions and changes to the proposed capital expenditure allowance noted above.

The roll forward for ETSA Utilities' RAB over the current regulatory control period from 1 July 2005 to 30 June 2010 is summarised in Table 12.1.

The opening 2005/06 balance differs from the value of $2,501.8 million referred to in Table 5.4 of the AER's Draft Determination and is reconciled in Table 12.2 below.

Table 12.1: RAB roll forward to 2010 (1)

	2005/06	2006/07	2007/08	2008/09	2009/10
Opening RAB	2,634.4	2,726.3	2,764.6	2,842.5	2,910.9
Plus capital expenditure, net of contributions and disposals	149.4	122.5	119.9	170.0	193.0
Less regulatory depreciation	(136.1)	(150.6)	(159.2)	(171.8)	(187.1)
Plus nominal actual inflation on opening RAB	78.6	66.4	117.3	70.2	67.2
Less difference between actual and forecast capex for 2004–05					(0.5)
Closing RAB	2,726.3	2,764.6	2,842.5	2,910.9	2,983.5

Nominal $ Million

Note:
(1) These calculations are extracted from the completed version of the AER's Post Tax Revenue Model.

Table 12.2: Reconciliation of 2005/06 Opening RAB Balance

	30 June 2005 RAB Value
Opening RAB at 1 July 2005 (Draft Decision, Table 5.4)	2,501.8
Add easement adjustment	116.2
Add 1999 RAB adjustment	16.3
Opening RAB at 1 July 2005 per Table 12.1	2,634.4

Nominal $ Million

The projected RAB for standard control services at the end of each year over the next regulatory control period is summarised in Table 12.3 below. The capital expenditure differs from the AER's Draft Determination, in accordance with chapter 6 of this Revised Proposal. Regulatory depreciation is higher than the AER's Draft Determination, due to the higher opening RAB and higher proposed capital expenditure. The opening 2010/11 balance in Table 12.3 differs from the value of $2,983.5 million referred to in Table 12.1 by $80.5 million, due to the allocation of metering assets to alternative control and negotiated services, as discussed in chapters 2 and 4. The projected RAB for alternative control services at the end of each year over the next regulatory control period is summarised in Table 12.4 below and includes the opening amount of $80.2 million transferred from standard control services.

Table 12.3: Standard Control Services RAB roll forward to 2015(1)

	2010/11	2011/12	2012/13	2013/14	2014/15
Opening RAB	2,903.0	3,177.4	3,492.0	3,754.7	4,010.3
Plus capital expenditure, net of contributions and disposals	372.7	426.8	388.6	397.5	399.8
Less regulatory depreciation	(169.4)	(190.1)	(211.5)	(233.8)	(255.4)
Plus nominal actual inflation on opening RAB	71.1	77.8	85.6	92.0	98.3
Closing RAB	3,177.4	3,492.0	3,754.7	4,010.3	4,253.0

Nominal $ Million

Note:
(1) These calculations are extracted from the completed version of the AER's Post Tax Revenue Model.

Table 12.4 Alternative Control Services RAB roll forward to 2015(1)

	2010/11	2011/12	2012/13	2013/14	2014/15
Opening RAB	80.2	89.2	98.4	105.5	113.1
Plus capital expenditure, net of contributions and disposals	12.7	13.5	12.4	13.7	13.8
Less regulatory depreciation	(5.6)	(6.6)	(7.7)	(8.7)	(9.9)
Plus nominal actual inflation on opening RAB	2.0	2.2	2.4	2.6	2.8
Closing RAB	89.2	98.4	105.5	113.1	119.8

Nominal $ Million

Note:
(1) These calculations are extracted from the completed version of the AER's Post Tax Revenue Model.

13

We do everything in our power to deliver yours

Weighted average cost of capital

13

WEIGHTED AVERAGE COST OF CAPITAL

In this chapter of the Revised Proposal, ETSA Utilities presents its response to the AER's Draft Determination on the weighted average cost of capital (WACC).

In response to the Draft Determination, and without necessarily agreeing with the basis for the AER's Draft Determination in respect of these parameters, ETSA Utilities has revised its Original Proposal to:

- adopt a value for the market risk premium parameter of 6.5%; and
- measure the debt risk premium by reference to the CBASpectrum service.

For the reasons set out in this chapter, ETSA Utilities does not accept the AER's Draft Determination with respect to the use of an imputation credit factor of 0.65 and maintains that an imputation credit factor of 0.5 is consistent with the requirements of the Rules.

13.1

MARKET RISK PREMIUM

13.1.1
Rule Requirements

Rule 6.5.2(b) requires that the rate of return for a DNSP is calculated in accordance with the Capital Asset Pricing Model (CAPM). The market risk premium (MRP) is an input to the CAPM and is the expected return above the risk free rate that investors would require to invest in a well diversified portfolio of securities. The MRP represents the level of non-diversifiable risk across all available investments.

The Statement of Regulatory Intent (SORI) adopted a MRP of 6.5 percent.

13.1.2
ETSA Utilities' Original Proposal

ETSA Utilities proposed a value of 8 percent for the MRP. At the time of lodging its Original Proposal ETSA Utilities considered this figure an appropriate reflection of the pricing of risk with regard to prevailing market conditions.

13.1.3
The AER's Draft Determination and Response

The AER adopted the SORI MRP figure of 6.5 percent. The AER stated that at the time of the Draft Determination there was not persuasive evidence to depart from the SORI value.[397]

ETSA Utilities adopts in this Revised Proposal, the SORI determined value for MRP of 6.5 percent, but does not necessarily agree or accept the underlying economic analysis in the Draft Determination on this subject. ETSA Utilities maintains that at the time of lodging its Original Proposal there was significant risk in financial markets that meant investors required a much higher medium term MRP than the SORI value.

13.1.4
Revised Proposal

Revised Proposal

ETSA Utilities adopts the SORI determined value for MRP of 6.5 percent, consistent with the AER's Draft Determination.

13.2

THE VALUE OF IMPUTATION TAX CREDITS

13.2.1
Rule Requirements

The Rules at clause 6.5.3 require the AER to make an allowance for the estimated cost of corporate tax. Rule 6.5.3 requires the application of the formula:

$$ETC_t = (ETI_t \times r_t)(1 - \gamma)$$

where:

ETI_t is an estimate of the taxable income for that regulatory year earned by a benchmark efficient entity.

r_t is the expected statutory income tax rate.

γ (gamma) is the assumed utilisation of imputation credits.

The gamma parameter identified in the Rules is the product of the value of imputation credits created as a proportion of their face value and the proportion of imputation credits that can be distributed. Gamma is estimated using the following formula:

$$\gamma = F.\emptyset$$

where γ (gamma), F is the payout ratio and ∅ (theta) is the value of imputation credits.

13.2.2
ETSA Utilities' Original Proposal

In the Original Proposal, ETSA Utilities proposed that the value of gamma should be 0.5, which was the prevailing value applied by the AER prior to the SORI.

13.2.3
The AER's Draft Determination and Response

The AER stated that it did not believe there to be persuasive evidence to justify a departure from the SORI value of 0.65. In summary, the AER concluded:[398]

- the arguments concerning an assumed 100 percent distribution rate, recognition of foreign investors, and limitations on theta inferred from tax statistics did not constitute new information;
- an assumed 100 percent distribution rate is consistent with the Officer framework and is appropriate given the difficulties in estimating the time value loss associated with retained credits;
- tax statistics are an appropriate proxy for theta;
- it had unresolved concerns with the work of Skeels and SFG, particularly surrounding multi-collinearity and filtering techniques;
- the study by Beggs and Skeels should not be labeled as a lower bound in the statistical sense; and
- 0.65 remains an appropriate estimate of theta.

ETSA Utilities has significant concerns with the position taken by the AER with respect to the value of imputation credits.

397 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 312.

398 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 276.

Distribution rate

ETSA Utilities considers that it is inappropriate to adopt a distribution rate of 1. The empirical evidence strongly suggests a distribution rate significantly less than 1, and this must be taken into account by the AER in its overall estimate of gamma.

The AER's theoretical position is largely informed by that of Handley. In the Draft Determination, the AER relies upon the proposition by Handley that a 100 percent payout ratio is consistent with the Officer framework and classical valuation frameworks.[399] In relation to this view, ETSA Utilities makes the following observations:

- Professor Officer has already addressed the AER's treatment of his framework, noting that the Officer framework said nothing about the payout ratio other than to make a simplifying assumption for the purposes of academic analysis;[400] and
- It is incorrect to rely upon a classical valuation framework as a basis for assuming a 100 percent payout ratio. A system of dividend imputation is an entirely different framework to a classical tax system.[401]

ETSA Utilities notes that in response to an information request, the AER provided further advice it received from Handley.[402] This advice states that it is "irrational" to assume that some earnings would never be paid out. ETSA Utilities accepts that this is true, however it does not imply that all franking credits must be paid out. SFG Consulting provide a simple example as to why this may not be the case.[403]

In the Draft Determination, the AER stated in respect of the time which retained credits are held, "it is unaware of any empirical analysis that specifically explores the issue".[404]

NERA have conducted new empirical analysis of Australian Tax Office (ATO) statistics, which provide direct and observable evidence that clearly demonstrate the assumption of a 100 percent payout ratio is at odds with the actual behavior of firms.[405] A copy of this report is presented as Attachment I.1. There is no support on a theoretical or empirical basis to justify the continued assumption of a payout ratio of 100 percent. A theoretical assumption which is directly contravened by actual evidence cannot be relied upon where observable evidence indicates the contrary.

Calculation of the payout ratio is informed by consideration of what proportion of credits are paid out in any one year, what period retained credits are held for, and what discount rate is to be applied in respect of those retained credits.

For the purposes of the analysis contained in this response, it is sufficient that ETSA Utilities address the AER's assumption that retained credits are distributed over a period of 1 to 5 years. It is common ground that the estimate of Hathaway and Officer of 0.71 is a reasonable approximation of the payout ratio in any one given year.[406] In respect of the appropriate discount rate, ETSA Utilities refers to the work of Officer and NERA in considering that the cost of equity is the appropriate discount rate.[407]

NERA has conducted a new empirical analysis of ATO statistics, which consistent with what Hathaway and Officer find, shows that on average 68 percent of franking credits were paid out between 1996-97 to 2006-07.[408]

NERA's analysis demonstrates that the AER's assumption that 71 percent of credits are paid out immediately and the rest within five years is at odds with the evidence on the payout ratio of an average firm in the market.[409] The ATO statistics indicate that if 71 percent of credits generated were paid out immediately, and the remaining 29 percent were paid out within five years, one would observe a payout ratio far in excess of what one sees in the data. If the remaining 29 percent were paid out within one year, one would observe a payout ratio of 97 percent. If the remaining 29 percent were paid out within five years, one would observe a payout ratio of 89 percent. The ATO statistics show that, in practice, the ratio of credits distributed to credits created in any year is far lower – again, on average, only 68 percent.

Professor Officer's report similarly addressed the assumption that all retained credits are paid out within a 1 to 5 year period. Professor Officer stated:[410]

399 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 260.

400 R Officer, Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers (23 June 2009).

401 NERA, Payout Ratio of Regulated Firms (5 January 2010) p 3.

402 J Handley, Memorandum to the Australian Energy Regulator re Advice on Gamma to the 2010-2015 Qld/SA Electricity Distribution Determinations (20 October 2009).

403 SFG Consulting, Response to AER Draft Determination in relation to gamma (13 January 2010) – paragraphs 78-83.

404 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 257.

405 The reasons for this include those identified by Mr Feros (eg, retaining capital to fund new investment, investor preferences for capital gains over income, and taxation rules limiting the ability of firms to payout credits).

406 AER, WACC Review, p 420.

407 ETSA Utilities notes that the AER considers that the appropriate rate is between the risk free rate and the cost of equity.

408 NERA, Payout Ratio of Regulated Firms (5 January 2010) p 6.

409 Note this does not require the payout ratio to be greater than 100%. On the basis of ATO data, a 97% payout ratio is consistent with all retained credits being paid within a year of being generated, not that all retained credits are paid out in any given year.

410 R Officer, Estimating the Distribution Rate of Imputation Tax Credits: Questions Raised by ETSA's Advisers (23 June 2009) p4. Note that the observation in footnote 13 is to be distinguished, as NERA's analysis considers what is necessary for retained credits to be paid out in a 1 to 5 year period on a rolling basis, and Professor Officer's analysis considers what the payout ratio would be required to be for all credits to be paid out in a 1 to 5 year period. In each case the empirical evidence is at odds with the AER's position.

"unless it can be shown that a company's payout ratio exceeds 100% at least every five years and then by an amount that ensures the distribution of all the accumulated retained earnings and their associated franking credits, then the AER assumption is empirically at odd(s) with the facts. For example, if a company had a 70% dividend payout rate for four years the fifth year payout rate would have to be 220% to exhaust the company's franking account balance (FAB account). The magnitude of the payout required to meet the AER assumption that earnings are paid out within five years of being earned is far greater than any empirical evidence would support."

In response to ETSA Utilities' information request, the AER stated that "[t]he range between one and five years was selected to reflect a retention of imputation credits reflective of the regulatory period".[411]

ETSA Utilities considers this to be a flawed approach, directly contradicted by empirical evidence. ETSA Utilities notes that it is common practice for regulators to observe certain parameters, such as the risk free rate, in the cost of capital calculation over the regulatory period. ETSA Utilities also acknowledges the GasNet principle, which requires WACC parameters to be estimated consistently so that the mathematical logic underpinning the CAPM is not undermined.[412]

However, the period in which credits are retained is an empirical question and it cannot simply be assumed that all credits would be paid out in a 1 to 5 year period because that corresponds with the regulatory period. The issue with the AER's analysis is that it starts from the proposition that 100 percent of retained credits will be paid over the regulatory period, before asking the appropriate question of what is the likely payout ratio over the regulatory period.

If this question were to be asked, the empirical evidence leads to a conclusion which cannot be disputed – the payout ratio must be less than 1.

The AER has not adequately addressed the significant practical restraints restricting the ability of firms to pay out retained credits identified in the Feros report ETSA Utilities submitted in conjunction with its Original Proposal.[413] ETSA Utilities accepts the AER's criticism of the Feros report that wastage of imputation credits is not a relevant factor in assessing the distribution rate. Nonetheless, the Feros report still correctly identifies constraints of practical significance, which restrict the ability of firms to distribute retained credits. The AER dismissed these actual constraints without proper consideration by stating that it could not predict what innovative financial activities a company may develop to pay out retained credits, and how the government may respond to such innovations.[414]

The AER has recognised a particular constraint facing ETSA Utilities' ability to payout retained credits in its treatment of equity raising costs. In the Draft Determination, the AER excluded capital contributions in calculating forecast dividends to be paid. This appears to have been because the AER considers that customer capital contributions are used to fund assets and those funds will not be available for distribution. Capital contributions generate an actual tax liability with associated franking credits and provide a unique example of the practical difficulty facing an electricity business such as ETSA Utilities.

Table 13.1 presents analysis using the figures advocated by the AER in the Draft Determination.[415] This analysis provides a unique example of why the payout ratio expected for a business such as ETSA Utilities should be less than 100 percent.[416]

Table 13. 1: Impact of exclusion of capital contributions on maximum distribution rate

	2010-11	2011-12	2012-13	2013-14	2014-15
Taxable Income—per PTRM ($m nominal)	304.2	313.9	308.7	324.3	335.7
Less capital contributions ($m nominal)	125.3	130.6	122.0	131.4	138.9
Taxable Income—excluding contributions ($m nominal)	178.9	183.3	186.7	192.8	196.8
Imputation credits generated in total	91.3	94.2	92.6	97.3	100.7
Imputation credits generated by capital contributions	37.6	39.2	36.6	39.4	41.7
Distributable imputation credits	53.7	55.0	56.0	57.9	59.0
Maximum distribution rate	59%	58%	60%	59%	59%
Average maximum distribution rate	59%				

411 AER, Response to ETSA Utilities information request dated 8 December 2009 (15 December 2009).

412 See, *Application by GasNet Australia (Operations) Pty Ltd* [2003] ACompT 6, [46].

413 P Feros, Review of WACC Parameters (22 June 2009).

414 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 259.

415 ETSA Utilities' calculations suggest that using the numbers in the Revised Proposal the average maximum distribution rate is 55%.

416 ETSA Utilities acknowledges that it may be appropriate for the AER to revise its approach in relation to equity raising costs to ensure consistency with the approach advanced by ETSA Utilities in relation to the distribution rate contained in this section of the Revised Proposal.

The empirical evidence and practical reality support a lower payout ratio than that advanced by the AER. However, ETSA Utilities recognises that retained credits will have some value and agrees with Handley and the AER that it is extreme to assume they have no value.[417] It is just as extreme to assume that they are fully valued. The fact that there are $150 billion worth of credits in franking account balances[418] is symptomatic of the constraints firms face in paying out these credits,
and is a stark representation of the overall value placed on imputation credits as a whole by the market. ETSA Utilities also notes that ATO statistics show a cumulative net increase in the levels of retained credits.[419]

ETSA Utilities believes the true value for the payout ratio on average lies between approximately 0.7 and 1. ETSA Utilities considers that since the empirical evidence suggests a payout ratio of greater than five years, and after taking into account the discounted value of retained credits and significant practical restraints, the true payout ratio is likely to be closer to 0.7 than 1. This must be taken into account by the AER in its overall assessment and estimate of gamma. ETSA Utilities considers that this position supports a gamma value of 0.50 and is inconsistent with the continued use of 0.65 by the AER.

Theta

Taxation statistics
ETSA Utilities maintains that statistics about franking credit redemption rates provide little information as to their value. This is supported by expert opinion, including that of Skeels.[420]

It is clear that this is a significant point of difference between ETSA Utilities and the AER. ETSA Utilities considers that taxation statistics can only provide an approximation on the upper bound (i.e. the maximum value) of the possible range of values for theta.

Dividend drop-off studies
In support of its Original Proposal, ETSA Utilities engaged Associate Professor Skeels to review dividend drop-off work undertaken by SFG, which was conducted using the same approach as that in Beggs and Skeels (2006)[421], but with an updated data set. This work specifically addressed concerns raised by the AER, for the first time, in the WACC Review Final Decision.

The Final Decision in the WACC Review presented a number of the AER's concerns with the SFG analysis, which were addressed by Skeels. Skeels evaluated each of the criticisms and found that they were either not substantiated by the evidence and / or have no material impact on the results.[422] ETSA Utilities did not accept the AER's basis for rejecting the results contained in the SFG study.

Despite this work, in its Draft Determination the AER stated that it still had a number of ongoing concerns with the SFG study, primarily in relation to the impact of multi-collinearity and the choice of filtering techniques.[423]

ETSA Utilities makes the following observations in respect of the AER's two chief criticisms:

- Multicollinearity: ETSA Utilities considers that the AER has overstated its concerns in relation to multicollinearity in the SFG study. In particular ETSA Utilities notes that the standard errors of the estimate do not suggest that multicollinearity represents any material concern. ETSA Utilities refers to the analysis contained in the Skeels and SFG reports.[424] The AER deemed the Beggs and Skeels (2006) market valuation of gamma to be sufficiently robust to adopt for the SORI. The issue of multicollinearity for the SFG market valuation is no different to the Beggs and Skeels (2006) market valuation.[425]
- Filtering / data quality: ETSA Utilities engaged Dr John Field, an independent statistician to prepare a statistically robust sampling methodology to be used to interrogate the SFG data set. A copy of Dr Field's report is presented as Attachment I.2. SFG subsequently conducted a rigorous sampling exercise. After a review of some 236 ASX announcements in relation to 150 observations, there is negligible change to the results previously reported by SFG.[426]

Skeels and SFG have fully addressed each of the AER's concerns discussed in the Draft Determination in Attachments I.3 and I.4 to this Revised Proposal. ETSA Utilities considers this to constitute new evidence that must be considered by the AER.

417 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 260.
418 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 260.
419 NERA, Payout Ratio of Regulated Firms (5 January 2010) p 6.
420 C Skeels, Response to Australian Energy Regulator Draft Determination (13 January 2010) section 2.
421 Beggs, D J and C L Skeels, 'Market Arbitrage of Cash Dividends and Franking Credits' *The Economic Record* (2006) 82 (258), pp 239-252.
422 C Skeels, A review of the SFG dividend drop off study (28 August 2009) pp10, 35.
423 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 276.
424 C Skeels, Response to Australian Energy Regulator Draft Determination (13 January 2010) section 3.1; SFG Consulting, Response to AER Draft Determination in relation to gamma (8 January 2010) paragraphs 19-34.
425 C Skeels, Response to Australian Energy Regulator Draft Determination (13 January 2010) p 18.
426 SFG Consulting, Response to AER Draft Determination in relation to gamma (13 January 2010) p 17. Dr Field has provided specific observations in relation to the results obtained from the SFG sampling exercise. This document is also contained as an annexure to Attachment I.2.

No method for estimating the true future value of a financial parameter is perfect. The AER's estimation of the WACC parameters in the SORI necessarily relies on imperfect financial analysis. Similar concerns that the AER raises in relation to the SFG market valuation of gamma can equally be raised in relation the financial analysis underpinning the SORI. It would be inconsistent for the AER to disregard similar concerns in the SORI decision, but to dismiss the SFG analysis on the same basis. Skeels has indicated that the concerns raised by the AER are of little practical importance and that the SFG estimate is the most accurate estimate currently available.[427] This ought to provide the AER with sufficient comfort that the SFG estimate meets the criteria underpinning the SORI.

ETSA Utilities also notes that the AER has placed significant weight on the filtering technique used by CommSec in the creation of the data set used by Beggs and Skeels.[428] ETSA Utilities observes that this data set has not been subject to the same levels of interrogation and scrutiny as the one used by SFG. The primary basis for the AER's view are remarks by Skeels as to what is likely to have been done by CommSec. However, the AER has not interrogated this data set, examined the filtering techniques or scrutinised the data set in any shape or form. In contrast, the data set used by SFG has been rigorously examined in an open and transparent fashion. In ETSA Utilities' opinion, this level of transparency and scrutiny requires the AER to give further consideration to the results of the updated SFG analysis and their implications as to the value of gamma and the overall reasonableness of adopting a gamma value of 0.5.

ETSA Utilities notes that a response from the AER on a further information request made on 17 December 2009 is still outstanding.[429] This information request sought further clarification with respect to the AER's approach in undertaking a selective comparison of Bloomberg and SFG data. Depending on the nature of the AER response, ETSA Utilities reserves the opportunity to comment on that response.

Other methodological concerns

ETSA Utilities has significant concerns with the AER's approach in averaging the results obtained from ATO statistics and dividend drop-off estimates.

ATO statistics by construction must be an upper bound on the possible range of theta. Taxation redemption rates will only provide an insight as to what the maximum value of theta could be. ATO statistics do not contain any information about what an investor would pay for the imputation credit. To average a point estimate from a dividend drop-off study with the maximum theoretical value will create an upward bias by construction in the value of theta. ETSA Utilities considers that this is a more than a deficiency in methodology, it raises a fundamental question as to the reasonableness of the AER's decision.

This is an issue which is exacerbated by the fact that a figure obtained from ATO statistics will overstate the range, in as far as not accounting for the time value loss associated with the time between when a franking credit is generated, and when it is applied to offset a tax liability.

Therefore, ETSA Utilities considers that the effect of the AER's methodology creates an inherently upwards bias in the estimation of theta.[430]

13.2.4 Revised Proposal

ETSA Utilities continues to advocate for a figure of 0.5 for the value of gamma. ETSA Utilities considers that it has sufficiently addressed the outstanding concerns of the AER, and that there is persuasive new evidence to depart from the SORI value.

ETSA Utilities' Revised Proposal should be accepted by the AER as:

- ETSA Utilities has demonstrated that there is direct and observable evidence demonstrating that the distribution rate is lower than 1 as currently applied by the AER;
- taxation statistics provide limited information on the market-based valuation of imputation credits;
- ETSA Utilities has presented what it considers to be the most thorough and comprehensive dividend drop-off analysis. This study has also been rigorously scrutinised in an open and transparent manner; and
- the AER has averaged the ATO statistics with a dividend drop-off study in a manner which will overstate the true value of theta.

ETSA Utilities considers its Revised Proposal to adopt a conservative and reasonable approach.[431]

ETSA Utilities notes the recent work of IPART. IPART recently conducted an independent review of the SORI value of 0.65. IPART noted that there was not sufficient evidence to warrant IPART departing from the view that the appropriate value for gamma was in the range of 0.30-0.50. IPART also observed that its practice has been to recognise:[432]

> *"that the available evidence on gamma indicates that gamma lies somewhere between 1 and 0, with the greater amount of studies indicating that gamma should be towards the lower end of this range."*

ETSA Utilities also notes that the AER's own consultant has stated that "a reasonable estimate of gamma is within the range of 0.3 – 0.7."[433] Handley had also reached this view assuming a distribution rate of 1.

427 C Skeels, A Review of the SFG Dividend Drop-Off Study (28 August 2009) p 5; C Skeels, Response to Australian Energy Regulator Draft Determination (12 January 2010) section 3.

428 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), pp 272-273.

429 The AER advised that a response would be made by mid January 2010.

430 ETSA Utilities refers to section 2 of C Skeels, Response to Australian Energy Regulator Draft Determination (13 January 2010).

431 ETSA Utilities notes that it is not necessary for the AER to accept all of the points above to adopt a gamma value of 0.5.

432 Independent Regulatory and Pricing Tribunal of New South Wales, *IPART's cost of capital after the AER's WACC review*, (November 2009) p 62.

433 J Handley, *A Note of the Valuation of Imputation Credits* (12 November 2008) p 22.

Revised Proposal
ETSA Utilities considers that the empirical evidence on the distribution rate and theta, as well as the views of the AER's own consultant, do not support the continued use of a gamma value of 0.65. The AER has chosen a value of theta at the upper end of the range advocated by its own consultant. A value of 0.5 is conservative, reasonable and consistent with a significant body of empirical evidence and expert opinion.

13.3

DEBT RISK PREMIUM

13.3.1
ETSA Utilities' Original Proposal

ETSA Utilities proposed that a simple average of the estimated yields reported by the Bloomberg and CBASpectrum services be used to measure the debt risk premium.

13.3.2
The AER's Draft Determination and Response

In making the Draft Determination, the AER undertook a comparison of what it termed the observed yields and fair values of a small sample of BBB+ corporate bonds from Bloomberg, CBASpectrum and UBS. The AER stated that it undertook this test in order to determine which service provides the "best available prediction of observed yields" for the purposes of determining the yield on the benchmark BBB+ 10 year corporate bond with respect to ETSA Utilities' averaging period. The AER concluded that the use of CBASpectrum's BBB+ fair value curve provided the best prediction for these purposes.[434]

In its Revised Proposal, ETSA Utilities accepts the AER's Draft Determination to measure the debt risk premium by reference solely to the CBASpectrum BBB+ fair value curve with respect to ETSA Utilities' averaging period.

However, in the context of recognising that the regulatory debate around the measurement of the debt risk premium will continue in relation to future regulatory proposals, ETSA Utilities makes the comments below.

ETSA Utilities has a number of significant concerns with the analysis conducted by the AER, and the basis upon which the AER determines in the Draft Determination that CBASpectrum provides the best available prediction of observed yields for the purposes of determining the yield on the benchmark BBB+ 10 year corporate bond with respect to ETSA Utilities' averaging period. ETSA Utilities does not consider that the "test" adopted by the AER is appropriate or robust.

ETSA Utilities commissioned a report from CEG, provided as Attachment I.5, to critique the AER's proposed methodology for testing whether the CBASpectrum BBB+ fair value curve, or the Bloomberg BBB+ fair value curve (as extrapolated by the AER) provides a better basis for arriving at an estimate of the observed annualised Australian benchmark corporate bond rate for corporate bonds with a BBB+ credit rating and a maturity of 10 years. This report takes as a given the broad parameters for the AER's proposed approach to testing the CBASpectrum and Bloomberg services, and identifies any areas where the approach could be improved.

ETSA Utilities also notes that given the opaqueness of the methodologies adopted by CBASpectrum and Bloomberg, together with the fact that these methodologies may change at any time without notification or explanation, there is a need to conduct a threshold "sense-check" of the relevant sources to test that they are reporting yields that are consistent with what may be expected given prevailing market conditions. Such a sense-check of the Bloomberg methodology during the period of the Global Financial Crisis would have revealed that during those market conditions, the Bloomberg service was reporting yields that were not consistent with the yields that could be expected given the prevailing market conditions. That is, the Bloomberg service performed poorly during this time. In this regard, ETSA Utilities refers to the report by PwC which, amongst other things, proposes a methodology to test whether the Bloomberg fair yield curves that the AER has relied on in previous determinations reasonably meets the legislative requirements.[435]

Finally, ETSA Utilities does not necessarily agree with the AER's interpretation of the Rule requirements relating to the cost of debt, in particular, its interpretation of "benchmark" in clause 6.5.2(e) as connoting efficiency of performance and not a bond rate that has "typical" or "usual" features.[436] While ETSA Utilities does not comment further on the AER's interpretation of the Rule requirements in its Revised Proposal, this should not be viewed as ETSA Utilities agreeing with the AER's interpretation of the relevant Rule requirements.

13.3.3
Revised Proposal

Revised Proposal
ETSA Utilities has accepted the AER's Draft Determination to measure the debt risk premium by reference solely to the CBASpectrum BBB+ fair value curve with respect to ETSA Utilities' averaging period. ETSA Utilities notes that this does not mean it accepts the basis upon which the AER has concluded in the Draft Determination that CBASpectrum's BBB+ fair value curve provides the best available prediction of observed yields for the purposes of determining the yield on the benchmark BBB+ 10 year corporate bond with respect to ETSA Utilities' averaging period.

434 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), pp 330 – 338.

435 Pricewaterhousecoopers, *Victorian Distribution Businesses: Methodology to Estimate the Debt Risk Premium*, (November 2009).

436 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 326.

13.4

EXPECTED INFLATION

13.4.1
ETSA Utilities' Original Proposal

ETSA Utilities proposed to use the AER's methodology in the NSW Electricity Distribution Determination for determining the inflation rate. This approach involved adopting an average of the Reserve Bank of Australia's (RBA) short-term inflation forecasts and the mid-point of its target inflation band.

13.4.2
The AER's Draft Determination and Response

In its Draft Determination, the AER considered the most reliable 10 year inflation forecast to be a geometric average of the RBA short term forecasts (currently extending out two years), and the mid-point of the RBA's target inflation range for the remaining years in the 10 year period.[437]

The AER notes that historically it had used a Fisher equation approach to forecast the expected inflation rate – being the difference between the Commonwealth Government Securities (CGS) (nominal) and the indexed linked CGS yields.[438] The AER continues that, as a consequence of what the AER considers to be a decrease of index-linked CGS being traded in the market, there is an increased likelihood that the market for these securities is "poorly functioning".[439] The AER concludes that the use of the Fisher equation technique is likely to be unreliable at this point in time.[440]

The Draft Determination then makes reference to an announcement by the Australian Office of Financial Management (AOFM) that it will be issuing indexed linked CGS around late September / early October 2009.[441] In September 2009, issuance of Treasury index bonds was resumed, with further issuance of these bonds to the undertaken by tender over the remainder of 2009-10.[442]

The AER concludes in its Draft Determination that, while the yields from indexed CGS are likely to be unreliable for the purposes of the Draft Determination as a consequence of the limited supply of these securities, the AER will re-examine this issue for the Final Decision in light of the AOFM announcement.[443]

ETSA Utilities is concerned if the AER, having accepted in its Draft Determination the methodology adopted by ETSA Utilities in its Original Proposal for determining the inflation rate, sought to apply an entirely different methodology in the Final Decision. In the current circumstances, ETSA Utilities does not consider that it is open to the AER to reserve its decision on the methodology for determining the inflation rate to the Final Decision.

An important purpose of the Draft Determination is to inform the relevant service provider of the determination of the AER in relation to the service provider's Original Proposal. In response to the Draft Determination, a service provider is entitled to submit a revised regulatory proposal to the AER, which may incorporate the substance of any changes required to address matters raised by the Draft Determination or the AER's reasons for it.[444] The AER's Draft Determination does not require any changes to ETSA Utilities' Original Proposal in relation to determining the inflation rate.

13.4.3
Revised Proposal

Revised Proposal

ETSA Utilities' Revised Proposal accepts the AER's Draft Determination on the methodology for determining the inflation rate. In these circumstances, ETSA Utilities does not consider that it is open to the AER in its Final Decision to adopt an entirely different methodology for determining the inflation rate from that proposed by ETSA Utilities, adopted by the AER in the Draft Determination, and accepted by ETSA Utilities in its Revised Proposal.

437 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 343.
438 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 343.
439 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 343.
440 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 343.
441 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 343.
442 http://www.aofm.gov.au/content/notices/24_2009.asp (accessed 14 December 2009).
443 AER, *Draft Decision South Australia: Draft distribution determination 2010-11 to 2014-15*, (25 Nov 2009), p 343 – 344.

444 National Electricity Rules, clause 6.10.3(b).

13.5

ETSA UTILITIES' PROPOSED WACC PARAMETERS

On the basis set out in this chapter, ETSA Utilities proposes WACC parameters that at the time of preparing its Revised Proposal deliver a nominal vanilla WACC of approximately 10.02%. In reaching this value, ETSA Utilities has adopted values for the WACC parameters as shown in Table 13.2.

With the exception of the gamma, the parameters used in the table below are from the SORI.

Table 13.2: ETSA Utilities' proposed WACC parameters

Parameter	Value(1)	Note
Nominal risk free rate	[5.37%]	
Expected inflation rate	[2.45%]	
Equity beta	0.80	Not revised from Original Proposal
Market risk premium	6.5	Revised from Original Proposal to adopt the market risk premium in the SORI
Gearing level (debt/equity)	0.60	Not revised from Original Proposal
Credit rating level	BBB+	Not revised from Original Proposal
Debt risk premium	[4.29%]	Revised from Original Proposal to be measured by reference to the CBASpectrum BBB+ fair value curve
Gamma	0.50	Not revised from Original Proposal
Nominal vanilla WACC	10.02%	

Note:

(1) The numbers in brackets are indicative 'place holders' only. They reflect the values measured for the period ended 13 October 2009 and will be updated with data from the agreed averaging period..

14

We do everything in our power to deliver yours

Depreciation

14

DEPRECIATION

In this chapter of the Revised Proposal, ETSA Utilities presents its updated forecast of depreciation for the current and future regulatory control periods.

The revision to ETSA Utilities' depreciation allowance is in response to matters raised by the AER. Specifically the revision to the regulatory proposal incorporates:

- The impact of changes to the opening RAB to correct for ESCOSA's treatment of capital contributions (chapter 12); and
- The impact of changes to forecast capital expenditure (chapter 6).

No amendments have been made to the methodology for calculating depreciation. The Post-tax Revenue Model (PTRM) has been used to calculate both the revised regulatory and tax depreciation allowances. This approach is consistent with the requirements set out in clauses 6.5.5 and S6.1.3(12) of the Rules.

The completed revised standard control services PTRM is provided as Attachment K.1 to this Revised Proposal.

The completed revised alternative control services PTRM is provided as Attachment K.2 to this Revised Proposal.

14.1

RULE REQUIREMENTS

Clause 6.4.3 of the Rules provides that the annual revenue requirement must be determined using a building block approach, which includes a component for depreciation calculated pursuant to clause 6.5.5.

In addition, clause S6.1.3(12) requires the depreciation schedules nominated by the distributor to be categorised by asset class or category driver, together with details of the amounts, values and other inputs used to compile the depreciation schedules, and a demonstration that the depreciation schedules conform with the requirements set out in clause 6.5.5(b) of the Rules.

14.2

ETSA UTILITIES' ORIGINAL PROPOSAL

ETSA Utilities applied the AER's PTRM to calculate depreciation on a straight line basis in accordance with clause 6.5.5 of the Rules. New assets were depreciated according to standard lives for each asset class. Existing assets were depreciated over their remaining asset lives. Opening asset values at 1 July 2010 have been calculated applying the AER's Roll Forward Model (RFM).

For the purposes of forecasting the cost of corporate income tax pursuant to clause 6.5.3 of the Rules, ETSA Utilities calculated tax depreciation in accordance with tax law. Tax depreciation is calculated on a straight line basis, using applicable tax depreciation rates. Chapter 15 provides further details on the allowance for corporate income tax.

ETSA Utilities' Original Proposal included forecast nominal regulatory depreciation of $1,124.3 million and tax depreciation of $610.3 million for the 2010–15 regulatory control period.

14.3

THE AER'S DRAFT DETERMINATION AND RESPONSE

The AER accepted the methodology adopted by ETSA Utilities for depreciation, but found that the standard life for office equipment applied in the roll forward model (RFM) should be changed to 5 years, consistent with the life applied by ESCOSA.

Revised Proposal

ETSA Utilities accepts the AER's findings with respect to depreciation and has incorporated the standard life for office equipment applied in the RFM of 5 years.

14.4

REVISED PROPOSAL

In accordance with the AER's Draft Determination, ETSA Utilities has calculated a revised depreciation forecast for the next regulatory control period. This calculation uses the AER's RFM and PTRM and applies the same methodology as in the Original Proposal, incorporating the standard life for office equipment applied in the RFM of 5 years, as noted in section 14.3 above.

Revised Proposal

Depreciation for alternative control services is provided, consistent with the breakout of metering as discussed in chapters 2 and 4.

The Revised Proposal depreciation is higher than the AER's Draft Determination. This is due to the revised depreciation calculation incorporating the changes to ESCOSA's treatment of capital contributions (chapter 12) and changes to the proposed capital expenditure allowance as reflected in this Revised Proposal (chapter 6).

Regulatory Depreciation for the 2005–2010 Regulatory Control Period is provided in Table 14.1. Forecast Regulatory Depreciation for the 2010–2015 Regulatory Control Period is provided in Table 14.2. Forecast Tax Depreciation for the 2010–2015 Regulatory Control Period is provided in Table 14.3.

Table 14.1: Regulatory Depreciation for the 2005–2010 Regulatory Control Period

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Regulatory Depreciation	136.1	150.6	159.2	171.8	187.1	804.9

Nominal $ Million

Table 14.2: Forecast Regulatory Depreciation

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Standard Control Services	169.4	190.1	211.5	233.8	255.4	1,060.2
Alternative Control Services	5.6	6.6	7.7	8.7	9.9	38.5

Nominal $ Million

Table 14.3: Forecast Tax Depreciation

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Standard Control Services	70.8	92.3	114.7	136.6	159.6	573.9
Alternative Control Services	3.2	3.7	4.3	4.7	5.3	21.2

Nominal $ Million

15

We do everything in our power to deliver yours

Estimated cost of corporate income tax

15

ESTIMATED COST OF CORPORATE INCOME TAX

In this chapter of the Revised Proposal, ETSA Utilities presents its updated forecast of corporate income tax for the 2010–2015 regulatory control period. Detailed supporting information is provided in Attachments J.1 to J.4 of this Revised Proposal.

The revision to ETSA Utilities allowance for corporate income tax is in response to matters raised by the AER in the Draft Determination. Specifically this incorporates:

- the impact of changes to the forecast capital expenditure (chapter 6);
- the impact of changes to the forecast operating expenditure (chapter 7);
- the impact of changes to the opening RAB for valuation of easements and ESCOSA's treatment of capital contributions (chapter 12); and
- the impact of changes to WACC parameters (chapter 13).

In this Revised Proposal, ETSA Utilities has not made any amendments to the methodology for calculating corporate income tax.

15.1

RULE REQUIREMENTS

Clause 6.5.3 of the Rules requires the estimated cost of corporate income tax to be calculated for each regulatory year in accordance with the formula as described in that section.

Until now, ETSA Utilities has been regulated on a 'pre-tax' basis. The pre-tax basis for regulation does not involve making an explicit allowance for corporate income tax and instead provides a return on capital invested that is sufficient for the tax to be paid by the investor. For the 2010–2015 regulatory control period, ETSA Utilities will move to post-tax regulation.

Clause 9.29.5(b) of the Rules states that the AER determination must incorporate appropriate transitional arrangements to take into account the change from a pre-tax to a post-tax revenue model.

15.2

ETSA UTILITIES' ORIGINAL PROPOSAL

ETSA Utilities' Original Proposal determined the estimated cost of corporate income tax for each regulatory year in accordance with the formula detailed in clause 6.5.3 of the Rules.

In addition, the Original Proposal considered in depth the issues associated with transitioning to post-tax regulation. The methodology for transitioning ultimately reflected the extensive consultations between ETSA Utilities, the AER and the AER's consultants, McGrath Nichol. Consistent with these consultations, the Original Proposal:

- identified the aggregate historic tax valuations of ETSA Utilities' assets;
- segregated assets into asset categories;
- proposed a treatment for work-in-progress;
- provided the tax depreciation lives to apply;
- confirmed that no tax losses are attributable to the provision of standard control services for the period from 11 October 1999 (start of regulation) to 30 June 2010;
- provided roll forward of the tax asset base to 2010 based on a clearly defined methodology;
- provided roll forward of the tax asset base to 2015 based on the opening tax asset base and proposed capital expenditures for 2010 to 2015; and
- provided the taxable income and estimated cost of corporate income tax.

The Original Proposal included, in nominal dollars, an opening tax asset base at 30 June 2010 of $1,159.5 million, a closing tax asset base at 30 June 2015 of $3,524.2 million, and an estimated cost of corporate income tax of $146.8 million.

15.3

THE AER'S DRAFT DETERMINATION AND RESPONSE

The AER accepted ETSA Utilities' methodology for corporate income tax, including the transition from pre to post-tax regulation. For the purposes of this Revised Proposal, ETSA Utilities has not revised the methodology for corporate income tax for transitioning to post-tax regulation.

The roll forward for the tax base in the Revised Proposal to 1 July 2010 incorporates actual capital expenditure for 2008-09, as determined by the AER in its Draft Determination. The roll forward to 1 July 2010 also incorporates:

- The previously determined capital expenditure allowance by ESCOSA for 2009/10 as the forecast for that year. This is consistent with the position taken by ETSA Utilities in its Original Proposal and it is considered to be the most appropriate forecast for roll forward as it ensures consistency with ESCOSA's ECM calculation for the current regulatory period. The difference between this amount and the actual amount will be reflected in the roll forward for 2015-20.
- The most recent forecast CPI for 2009/10, based on actual CPI to September 2009 plus forecast CPI as per the Reserve Bank of Australia's Statement of Monetary Policy, released November 2009.

The AER has included the gifted asset forecasts proposed by ETSA Utilities in the calculation of the tax allowance in the Draft Determination. However, as a consequence of ETSA Utilities providing the relevant information on gifted assets after the submission of its Original Proposal, the AER has advised that it may review this matter, including the forecasts, in reaching the Final Decision.

Revised Proposal

To the extent that the AER considers that it may take an approach to gifted assets that is different to that set out in the Draft Determination, ETSA Utilities requests that there be appropriate consultation with respect to this matter, prior to the Final Decision being made by the AER.

15.4

REVISED PROPOSAL

In accordance with the AER's findings, ETSA Utilities has calculated a revised tax forecast for the next regulatory control period. This calculation uses the AER's roll forward model (RFM) and post-tax revenue model (PTRM) and applies the same methodology as in the Original Proposal, incorporating the changes noted above.

Revised Proposal

The tax forecast for alternative control services is also provided consistent with the breakout of metering as discussed in chapters 2 and 4.

Table 15.1 provides the revised tax asset base roll forward to 2010, and Tables 15.2 and 15.3 provide the revised tax asset base roll forward to 2015. Table 15.4 provides the revised taxable income, and Table 15.5 provides the revised estimated cost of corporate income tax.

Table 15.1: Tax Asset Base roll forward to 2010

	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00
Opening Tax Asset Base	323.0	339.1	396.1	408.5	418.9	465.7	469.2	500.3	526.2
Plus capital expenditure	45.0	81.0	35.5	36.1	76.8	37.9	69.1	68.7	75.0
Less disposals									2.2
Less regulatory tax depreciation	28.8	24.0	23.1	25.8	30.1	34.4	38.0	42.8	46.9
Closing Tax Asset Base	339.1	396.1	408.5	418.9	465.7	469.2	500.3	526.2	552.2

Nominal $ Million

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Opening Tax Asset Base	552.2	556.9	599.0	633.2	658.1	666.2	746.0	781.1	841.0	933.1
Plus capital expenditure	78.7	130.0	123.7	136.5	115.9	193.5	169.6	213.2	296.8	225.0
Less disposals	(1.2)	(1.1)	(2.5)	(3.1)	(1.9)	(3.6)	(5.8)	(2.3)	(4.4)	(3.4)
Less customer contributions	(25.0)	(36.9)	(29.8)	(41.7)	(53.5)	(53.6)	(60.8)	(77.9)	(121.5)	(35.1)
Less regulatory tax depreciation	(47.8)	(49.9)	(57.2)	(66.8)	(52.4)	(56.5)	(67.9)	(73.1)	(78.8)	(88.2)
Closing Tax Asset Base	556.9	599.0	633.2	658.1	666.2	746.0	781.1	841.0	933.1	1031.5

Nominal $ Million

Table 15.2: Tax Asset Base roll forward to 2015 – Standard Control Services

	2010/11	2011/12	2012/13	2013/14	2014/15
Opening Tax Asset Base (including WIP of $118.9 m) and excluding meter assets of $58.8 for alternative control and $0.3m for negotiated services)	1,091.3	1,507.7	1,958.7	2,339.7	2,715.3
Plus capital expenditure, net disposals	487.2	543.3	495.7	512.2	520.4
Less regulatory tax depreciation	(70.8)	(92.3)	(114.7)	(136.6)	(159.6)
Closing Tax Asset Base	1,507.7	1,958.7	2,339.7	2,715.3	3,076.1

Nominal $ Million

Table 15.3: Tax Asset Base roll forward to 2015 – Alternative Control Services

	2010/11	2011/12	2012/13	2013/14	2014/15
Opening Tax Asset Base	58.8	68.1	77.6	85.6	94.2
Plus capital expenditure, net disposals	12.5	13.3	12.2	13.4	13.5
Less regulatory tax depreciation	(3.2)	(3.7)	(4.3)	(4.7)	(5.3)
Closing Tax Asset Base	68.1	77.6	85.6	94.2	102.4

Nominal $ Million

Table 15.4: Taxable income

	2010/11	2011/12	2012/13	2013/14	2014/15
Standard Control Services	311.8	322.9	319.3	336.3	349.1
Alternative Control Services	4.8	5.5	6.3	7.1	8.0

Nominal $ Million

Adopting a corporate tax rate (r_t,) of 30% and ascribing a utilisation value for imputation credits (γ) of 0.50, the estimated cost of corporate income tax (ETC_t) for each year of the regulatory period is provided in Table 15.5.

Table 15.5: Estimated cost of corporate income tax

	2010/11	2011/12	2012/13	2013/14	2014/15
Standard Control Services	32.7	33.9	33.5	35.3	36.7
Alternative Control Services	0.7	0.8	1.0	1.1	1.2

Nominal $ Million

16

We do everything in our power to deliver yours

Indicative revenue and pricing

16

INDICATIVE REVENUE AND PRICING

In this chapter of the Revised Proposal, ETSA Utilities sets out its calculation of annual revenue requirements for the provision of standard control services and alternative control services for each year of the next regulatory control period. The chapter also sets out the X factors to be applied as part of the weighted average price cap (WAPC) to apply to the provision of standard and alternative control services. As detailed in chapters 2 and 4, in this Revised Proposal ETSA Utilities has incorporated the AER's classification of services set out in the Draft Determination by separating metering services from standard control services.

The methodology utilised to derive these prices is in accordance with the requirements of Chapter 6 of the National Electricity Rules (the Rules) and employs the AER's Post-Tax Revenue Model (PTRM). ETSA Utilities' completed standard control services and alternative control services PTRMs are provided as Attachments K.1 and K.2 to this Revised Proposal.

Both the revenues and prices presented in this chapter represent indicative or 'placeholder' numbers only in that they are based upon:

- The average risk free rate and debt margin as determined by the AER in the Draft Determination. It is noted that the final values for these parameters will be based upon those observed in the measurement period to be specified by ETSA Utilities;
- An interim forecast of the revenue adjustments from the previous regulatory control period, which have been applied as an EDPD pass through as determined by the AER in the Draft Determination [445]; and
- Estimated sales quantities for 2008/09 which, subject to materiality, would be updated when audited quantities are available in March 2010.

Prices are further subject to any tariff re-design ETSA Utilities may recommend as part of its pricing proposal to the AER in May 2010.

445 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, AER, p.50

16.1

RULE REQUIREMENTS

Chapter 6 of the Rules requires the application of a building block approach to the regulation of standard control services. Clause 6.3.2(a) provides that a building block determination for a Distribution Network Service Provider (DNSP) is to specify, amongst other things, the DNSP's annual revenue requirement for each regulatory year of the regulatory control period.

Clause 6.4.3 provides that the annual revenue requirement for a DNSP for each regulatory year of a regulatory control period must be determined using a building block approach, under which the relevant building blocks are:

- indexation of the regulatory asset base;
- a return on capital for that year;
- the depreciation for that year;
- the estimated cost of corporate income tax of the provider for that year;
- the revenue increments and decrements (if any) for that year arising from the application of the efficiency benefit sharing scheme, the service target performance incentive scheme, and the demand management incentive scheme;
- the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period; and
- the forecast operating expenditure of that year.

Rule 6.5 contains the specific requirements for the building block components, which are used to establish an unsmoothed revenue requirement. The resulting price path to deliver this revenue is then smoothed with an X factor or factors in accordance with the requirements of clause 6.5.9.

This chapter outlines the derivation of allowable annual revenues, prices and the associated X factors to meet the requirements of clause S6.1.3(6) of the Rules. The associated detail of all amounts, values and inputs relevant to the calculation is contained in other chapters of this Revised Proposal, its attachments and the PTRM.

ETSA Utilities has also applied a building block methodology to its alternative control services. ETSA Utilities also uses the AER's PTRM to calculate ETSA Utilities' annual revenue requirement for each regulatory year of the regulatory control period for its alternative control services.

This chapter also contains indicative prices for standard control services and alternative control services for each year of the regulatory control period as required by clause 6.8.2(c)(4) of the Rules.

16.2

ETSA UTILITIES' ORIGINAL PROPOSAL

In its Original Proposal, ETSA Utilities accepted the classification of services as proposed in the Framework and approach paper other than the intended reclassification of metering services as alternative control services. As a consequence, ETSA Utilities did not separate its annual revenue requirements and X factors into standard control and alternative control services.

ETSA Utilities proposed a total revenue requirement for the next regulatory control period of $3,720 million (nominal) for the provision of standard control services. The calculation of this revenue requirement is provided in Table 16.1[446].

ETSA Utilities proposed an X factor of -10 percent for each year of the next regulatory control period[447].

The impact of ETSA Utilities' proposed X factors in terms of real end use prices equated to an increase of 4 percent per annum, or $25 per annum over the next regulatory control period for a typical residential customer. Note that the calculations assume distribution charges make up 40 percent of an end users bill.

The impact of the X factors in terms of real end use prices arising from ETSA Utilities' Original Proposal for the next regulatory period are shown in Table 16.2

446 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.271.
447 ETSA Utilities, *ETSA Utilities Regulatory Proposal 2010–2015*, July 2009, p.271.

16.3

THE AER'S DRAFT DETERMINATION

The AER's Draft Determination resulted in a total revenue requirement over the next regulatory control period of $3,549 million (nominal), compared to the $3,720 million (nominal) proposed by ETSA Utilities[448]. The main reasons for this difference reflect:

- removal of $243 million from ETSA Utilities' opening RAB;
- removal of $638 million from ETSA Utilities' forecast capital expenditure;
- removal of $131 million from ETSA Utilities' forecast operating expenditure; and
- the use of a higher WACC than proposed by ETSA Utilities in its Original Proposal.

In deciding ETSA Utilities' X factors, the AER decided not to apply a constant X factor for the next regulatory control period as proposed by ETSA Utilities. The AER considered that to do so would lead to a significant divergence between ETSA Utilities' expected revenues and the annual revenue requirement for the last year of the next regulatory control period. The AER considered that a P0 of -10.95 percent for 2010/11 and X factors of -3.90 percent for 2011/12–2014/15 were reasonable. The size of these X factors were significantly affected by the forecasts of ETSA Utilities' sales that were adopted by the AER.[449]

The impact of the X factors in terms of real end use prices proposed by the AER for the next regulatory period are detailed in Table 16.3.[450]

Table 16.1: ETSA Utilities' Original Proposal unsmoothed annual revenue requirement

Building block element	2010/11	2011/12	2012/13	2013/14	2014/15
Return on Capital	272.3	301.9	340.3	377.1	411.7
Depreciation	100.5	115.4	130.4	147.7	165.2
Operating expenditure	208.3	225.4	242.9	263.5	280.7
Tax allowance	27.0	28.6	28.5	30.8	31.9
Other revenue adjustments	(16.5)	1.7	3.4	2.0	-
Unsmoothed revenue requirement	**591.6**	**673.0**	**745.4**	**821.1**	**889.4**

Nominal $ Million

Table 16.2: Real price impacts (%)

	2010/11	2011/12	2012/13	2013/14	2014/15
ETSA Utilities' Original Proposal	4.0	4.0	4.0	4.0	4.0

Table 16.3: Real price impacts (%)

	2010/11	2011/12	2012/13	2013/14	2014/15
AER Draft Determination	4.4	1.6	1.6	1.6	1.6

448 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, AER, p.418.

449 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, AER, p.419.

450 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, AER, p.419.

16.4

REVISED PROPOSAL

16.4.1 Building block revenue components and the annual revenue requirement

The annual revenue requirement for standard control services and alternative control services, both developed utilising the building block approach, comprise a number of components that are discussed in detail in other sections of this Revised Proposal.

Standard control services

The building block components and resulting annual revenue requirement derived via the standard control services PTRM are set out in Table 16.4.

Alternative control services

The building block components and resulting annual revenue requirement derived via the alternative control services PTRM are set out in Table 16.5.

16.4.2 Revenue adjustment arising from the previous regulatory control period

For standard control services, a transitional revenue adjustment needs to be carried forward to the 2010-15 regulatory control period, arising from the application of the control mechanism in the current regulatory control period. ETSA Utilities has applied the transitional $EDPD_t$ factor as an annual adjustment, as required by the AER in the Draft Determination.[451] This adjustment is an estimate only of the combined impact of the components of the $EDPD_t$. ETSA Utilities' preliminary estimate of the value of $EDPD_t$ is $28 million, which would be returned to customers in 2010/11. Further true-ups will be applied in subsequent years if required. The $28 million will be revised with updated information in May 2010 as part of ETSA Utilities' pricing proposal.

Table 16.4: Building block components—standard control services

Component	2010/11	2011/12	2012/13	2013/14	2014/15
Return on capital	291.0	318.5	350.0	376.4	402.0
Regulatory depreciation	98.3	112.2	125.9	141.8	157.2
Operating expenditure	204.4	218.0	232.0	249.4	262.2
Tax allowance	49.0	50.4	49.4	51.6	53.3
Unsmoothed revenue requirement	642.7	699.1	757.3	819.2	874.7

Nominal $ Million

Table 16.5: Building block components—alternative control services

Component	2010/11	2011/12	2012/13	2013/14	2014/15
Return on capital	8.0	9.0	9.9	10.6	11.3
Regulatory depreciation	3.6	4.4	5.3	6.1	7.1
Operating expenditure	6.6	6.8	7.2	7.6	8.0
Tax allowance	0.7	0.8	1.0	1.1	1.2
Unsmoothed revenue requirement	19.0	21.0	23.3	25.4	27.7

Nominal $ Million

451 AER, *Draft Decision South Australia: Draft distribution determination 2010–11 to 2014–15*, 25 Nov 2009, AER, p.50.

16.4.3
X factors for direct control services

Under a WAPC form of control, forecast sales quantities must be utilised to derive X factors to be applied to the price control formula. In accordance with clause 6.5.9 of the Rules, these X factors must be calculated so as to deliver the same net present value as the annual revenue requirements set out in Tables 16.4 and 16.5.

ETSA Utilities has utilised the formula included in the AER's PTRM to establish the X factors for standard control services and alternative control services.

Standard control services

ETSA Utilities proposes that the standard control services X factors for each year of the regulatory control period (P_0, and X_1 to X_4) be made equal after the effect of estimated $EDPD_t$ adjustments. This approach will deliver a relatively smooth price path within the 2010–15 regulatory control period, particularly at the beginning of the period when the $EDPD_t$ carryovers are returned.

Under this approach, the X factors derived via the standard control services PTRM (the 'raw' X factors) have been set to allow for the subsequent inclusion of $EDPD_t$. The inclusion of EDPDt has the effect of adjusting the raw X factors over the regulatory control period. This approach provides a smooth price path, and one where the variance between expected revenue in the last regulatory year of the regulatory control period and the annual revenue requirement is 8.6 percent.

The resulting X factors for each year of the regulatory control period are set out in Table 16.6.

To some extent, the initial price increment, P_0, is a result of ETSA Utilities' prices having been set at deflated levels in 2009/10. Prices are at these levels due to the impact of the 'Q-factor' in the current regulatory control period.

The Q-factor shares sales volume variance risk between ETSA Utilities and customers. Approximately 85 percent of revenue resulting from sales volumes exceeding forecasts must be returned to customers through lower prices. This impact has decreased ETSA Utilities' 2009/10 average prices by approximately 4.7 percent, and provides a significant component of the EDPDt adjustment in 2010/11.

Thus the effective price rise of 10.4 percent at the commencement of the 2010-15 regulatory control period is materially larger than would have been the case if 2009/10 prices were at cost reflective levels.

Alternative control services

ETSA Utilities proposes that the alternative control services X factors for each year of the regulatory control period (P_0 and X_1 to X_4) be made equal, to deliver a smooth price path within the 2010–15 regulatory control period and at the end of the period.

The X factors are presented in table 16.7.

Table 16.6: X Factors—standard control services

Overall price trajectory	2010/11	2011/12	2012/13	2013/14	2014/15
	P_0	X_1	X_2	X_3	X_4
Raw P_0 and X factors	-15.6%	-6.0%	-10.5%	-10.5%	-10.5%
$EDPD_t$ adjustment	5.2%	-4.5%	-	-	-
Effective P_0 and X factors	-10.4%	-10.5	-10.5%	-10.5%	-10.5%

Note:
(1) Note: a negative X factor represents a real increase in distribution prices.

Source: Attachment K.1

Table 16.7: X Factors—alternative control services

Overall price trajectory	2010/11	2011/12	2012/13	2013/14	2014/15
	P_0	X_1	X_2	X_3	X_4
P_0 and X factors	-9.18%	-9.18%	-9.18%	-9.18%	-9.18%

Note:
(1) Note: a negative X factor represents a real increase in metering prices.

Source: Attachment K.2

16.4.4 Indicative prices for direct control services

Indicative prices for standard control services

The indicative prices for standard control services outlined in this section are forecast to recover revenues equal to, in net present value terms, the unsmoothed revenue requirement for standard control services set out in Table 16.4. These indicative prices relate to the tariff classes selected for the next regulatory control period described in section 4.5 of ETSA Utilities' Original Proposal, but the controlled load price has again been separately itemised for clarity.[452]

The notional 2009/10 revenue that would have been recovered from metering services prices had they been applied, has been removed from the standard control services PTRM by reducing the supply charge to residential, business single-rate and business two-rate customers by the amounts noted in Table 16.8. These reductions were undertaken to ensure that the total revenue derived by the PTRM for 2009/10 reconciles exactly to ETSA Utilities' tariff submission for that year.

Indicative energy prices for each tariff class for the next regulatory control period are shown in Table 16.9. The prices are shown as an average $/MWh, as each price has a number of components, and actual prices will depend upon the consumption of various components.

Indicative prices for alternative control services

The indicative prices for alternative control services set out in Table 16.10 are forecast to recover revenues equal to, in net present value terms, the unsmoothed revenue requirement for alternative control services set out in Table 16.5. These indicative prices relate to the metering services tariff class tariff components described in Attachment D.1 of this Revised Proposal.

Notional 2009/10 metering alternative control services tariffs, developed to comply with the alternative control services classification of the Framework and approach paper, have been adjusted to equate notional 2009/10 metering alternative control services revenue with the $15.7 million removed from the standard control services PTRM as noted in section 16.4.4.

ETSA Utilities will demonstrate compliance with the alternative control services price control by providing the proposed tariffs that correspond to the price terms contained in the WAPC equation with its pricing proposal in May of 2010, and in each year of the next regulatory control period. ETSA Utilities has described and demonstrated this compliance in Attachment D.1.

Table 16.8: Alteration to standard control services supply charge in 2009/10

Supply charge adjustment to offset metering charge	2009/10 base	2009/10 adjustment	2009/10 adjusted
Residential	95.87	(19.19)	76.68
Business single-rate	95.87	(19.19)	76.68
Business two-rate	109.53	(32.85)	76.68

$ 2009/10

Table 16.9: Indicative energy prices for standard control services

Tariff class	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Major business	6.21	6.71	6.86	7.29	8.04	8.87
High voltage business	21.95	25.03	26.60	29.34	32.36	35.69
Low voltage business and unmetered supplies (excluding controlled load)	44.63	50.57	52.91	58.39	64.45	71.13
Low voltage residential (excluding controlled load)	75.45	87.03	92.75	102.59	113.47	125.49
Controlled load	18.14	20.91	22.27	24.61	27.19	30.05

$/MWh, 2009/10 real, excluding GST

452 As discussed in section 16.4 of ETSA Utilities' Original Proposal, p.274, controlled load has been subject to rapidly declining sales volumes.

16.4.5 Average bills for direct control services for small customers

ETSA Utilities has estimated the annual combined bill for standard control services and alternative control services for typical small customers, which is set out in Table 16.11.

In preparing these estimates it has been assumed that a typical small business[453] customer consumes 10 MWh of energy each year, and that a typical residential customer consumes 5 MWh in 2009/10, declining to just over 4 MWh by 2014/15. It is also assumed that both typical customers utilise direct current connected type 6 meters and are billed quarterly.

Table 16.10: Indicative energy prices for alternative control services

Metering Services	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Meter Provision Type 6 Direct Current Connected ($/day)	0.05246	0.05728	0.06254	0.06837	0.07472	0.08164
Meter Provision Type 6 Current Transformer Connected ($/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)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
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	667.97	667.97	667.97	667.97

2009/10 real, excluding GST
Source: RIN63

Table 16.11: Indicative small customer bills for direct control services

Customer type	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Residential	$398	$429	$465	$499	$537	$579
Small business	$761	$841	$929	$1,026	$1,133	$1,253

$ per annum, 2009/10 real

453 Single rate, low Voltage

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Attachments to the Revised Proposal

A.1	Directors' certification
B.1	ETSA Utilities' revised Negotiating Framework
C.1	Treatment of TUoS recovery
D.1	Classification of alternative control metering services
E.1	Frontier Economics: Econometric review of the AEMO sales models methodology
E.2	MMA: Review of post-model adjustment methodology
E.3	Summary review of AEMO sales forecast
E.4	Frontier Economics: Econometric review of the Monash demand model methodology
E.5	Access Economics: Forecast of economic variables for SA
E.6	KPMG Econtech: Forecast of economic variables for SA
E.7	NIEIR: Energy sales forecast
E.8	Derivation of ETSA Utilities' average economic variables for SA
E.9	Spatial demand forecasting processes – description of ETSA Utilities' approach
E.10	NIEIR: Global peak demand forecast
E.11	NIEIR: Relevant experience
E.12	Hot water sales – methodology
E.13	Post-model forecast adjustments to sales – methodology
F.1	Revised capital submission expenditure model
F.2	Evans and Peck: Low voltage planning review
F.3	Heatwave test sample analysis
F.4	Capital expenditure costing
F.5	EA Technology: The significance of asset age in estimating remnant life/end of life for substation plant
F.6	Poles model output has been updated to reflect historical ratios of pole replacement to total pole treatments
F.7	JWS: Advice regarding substation fencing
F.8	KEMA: Letter regarding operational staff cost clarification
F.9	Equity raising costs
F.10	Real cost escalation
F.11	Audit trail documentation from Original Proposal to Draft Determination to Revised Proposal
F.12	CX001 updated with Revised Proposal variations
G.1	Revised operating submission expenditure model
G.2	Revised derivation of ETSA Utilities' scale escalators
G.3	SKM: Analysis of ETSA Utilities' asset age and condition profile – supplementary report
G.4	EISS: Updated advice regarding employer contributions
G.5	Detailed response regarding self insurance
G.6	CEG: Review of AER's Draft Determination regarding debt raising costs
G.7	Structure and application of the opex SEM
H.1	Standard control services Roll Forward Model
H.2	Alternative control services Roll Forward Model
I.1	NERA: Payout ratio of regulated firms
I.2	Field: Reliability of data used in dividend drop-off study
I.3	Skeels: Response to Australian Energy Regulator Draft Determination
I.4	SFG: Response to AER determination in relation to gamma
I.5	CEG: Testing the accuracy of Bloomberg vs CBA Spectrum fair value estimates

J.1	Section 1 – Asset addition schedules 1970–1999
J.2	Section 2 – Asset addition schedules 1999–2004
J.3	Section 3 – Tax base at 2004
J.4	Section 4 – Tax remaining life at 2010
K.1	Standard control services Post-tax Revenue Model
K.2	Alternative control services Post-tax Revenue Model