DRAFT 2005 - 2010 ELECTRICITY DISTRIBUTION PRICE DETERMINATION

PART A - STATEMENT OF REASONS

Essential Services Commission Act 2002
Electricity Act 1996

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REQUEST FOR SUBMISSIONS

The Essential Services Commission of SA (the Commission) invites written submissions from interested parties in relation to the issues raised in this paper. Written comments should be provided by **11 February 2005**. It is highly desirable for an electronic copy of the submission to accompany any written submission.

It is Commission policy to make all submissions publicly available via its website (www.escosa.sa.gov.au), except where a submission either wholly or partly contains confidential or commercially sensitive information provided on a confidential basis and appropriate prior notice has been given.

The Commission may also exercise its discretion not to exhibit any submission based on their length or content (for example containing material that is defamatory, offensive or in breach of any law).

Responses to this paper should be directed to:

EDPR 2005-2010: Draft Determination

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Public Information about ESCOSA's activities

Information about the role and activities of the Commission, including copies of latest reports and submissions, can be found on the ESCOSA website at www.escosa.sa.gov.au.

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GLOSSARY OF TERMS

ACCC	Australian Competition and Consumer Commission as established by the *Trade Practices Act 1974*
AGL SA	AGL South Australia
AGSM	Australian Graduate School of Management
ARBN	Australian Registered Business Number
ASIC	Australian Securities and Investments Commission
ASX	Australian Stock Exchange
AV	Asset Value
B2B	Business to Business
CACWG	Consumer Advisory Committee Working Group
CAIDI	Customer Average Interruption Duration Index – the average duration of each supply interruption per customer who experienced a supply interruption within the distribution network (or defined part of the distribution network)
CAPM	Capital Asset Pricing Model
CAPEX	Capital Expenditure
CBA	Commonwealth Bank of Australia
CBD	Central Business District
CLC	Curtailable Load Control
CLER	Customer Lighting Equipment Rate, where provision of public street lighting service relates only to the operation and maintenance of street lighting
COMMISSION	Essential Services Commission of SA established under the *Essential Services Commission Act 2002*. This legislation repealed the *Independent Industry Regulator Act 1999*. The Commission is the same body corporate as the former SA Independent Industry Regulator.
CPI	Consumer Price Index
CPP	Critical Peak Pricing
CRA	Charles River Associates (Asia Pacific) Pty Ltd
DEP	Depreciation
DLC	Direct Load Control
DGM	Dividend Growth Model
DNLL	Distribution Network Land Lease
DNSP	Distribution Network Service Provider
DORC	Depreciated Optimised Replacement Cost
DUOS	Distribution Use of System
ECM	Efficiency Carryover Mechanism
EPO	Electricity Pricing Order as made by the Treasurer, pursuant to S.35B of the *Electricity Act 1996*, on 11 October 1999.
ERSU	Electricity Reform and Sales Unit (within the SA Department of Treasury and Finance)
ESC ACT	Essential Services Commission Act 2002
ESCOSA	Essential Services Commission of South Australia (the Commission)
ESIPC	Electricity Supply Industry Planning Council (SA)

ETSA UTILITIES	ETSA Utilities is a partnership of CKI Utilities Development Limited (ARBN 090 718 880), HEI Utilities Development Limited (ARBN 090 718 951), CKI Utilities Holdings Limited (ARBN 091 142 380), HEI Utilities Holdings Limited (ARBN 091 142 362) and CKI/HEI Utilities Distribution Limited (ARBN 091 143 038) which is authorised to operate an electricity distribution network by an electricity distribution licence issued by the Commission under section 17(1) of the Electricity Act 1996.
FRC	Full Retail Contestability, the situation in which all electricity customers become contestable.
GDP	Gross Domestic Product
GIS	Geographic Information System
GNP	Gross National Product
GSL	Guaranteed Service Level
GSP	Gross State Product
GST	Goods and Services Tax introduced from 1 July 2000
HV	High Voltage
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IT	Information Technology
IVR	Integrated Voice Response, an automated system used for answering telephone calls
KVA	Kilovolt Ampere
KW	Kilowatt
KWH	Kilowatt-hours, which is the equivalent of 1,000 Wh
LGA	Local Government Association of SA
LV	Low Voltage
MADR	Maximum Average Distribution Revenue
MRP	Market Risk Premium
MW	Megawatt
MWH	Megawatt-hour
NEC	National Electricity Code
NECA	National Electricity Code Administrator
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NIEIR	National Institute of Economic and Industry Research
NPV	Net Present Value
NSW	New South Wales
O&M	Operating and Maintenance
ODV	Optimised Deprival Cost
OMS	Outage Management System
OPEX	Operating Expenditure
OTR	Office of the Technical Regulator (SA)
P.A.	Per Annum
PBA	PB Associates
PI SCHEME	Performance Incentive scheme, refers to the Performance Incentive Scheme, established under the Electricity Distribution Code

PLEC	Powerline Environment Committee
PoE	Probability of Exceedance
PKF	PKF Accounting
QCA	Queensland Competition Authority
ROA	Return on Assets
RoLR	Retailer of Last Resort
SA	South Australia
SACES	South Australian Centre for Economic Studies
SAIDI	System Average Interruption Duration Index – the length of time each customer is without supply when averaged over all customers in the distribution network (or defined part of the distribution network)
SAIFI	System Average Interruption Frequency Index – the number of supply interruptions each customer experiences for the year when averaged over all customers on the distribution network (or defined part of the distribution network)
SAIIR	South Australian Independent Industry Regulator, established by S.4 of the *Independent Industry Regulator Act 1999*. The SAIIR was replaced by the Commission in September 2002.
SCADA	Supervisory Control and Data Acquisition
SCONRRR	Steering Committee on National Regulatory Reporting Requirements
SI SCHEME	Service Incentive scheme
SKM	Sinclair Knight Merz
SLA	Service Level Agreement
SLUOS	Street Light Use of System, where the provision of public street lighting service includes the provision of the assets along with the maintenance and operation of those assets
SSF	Service Standard Framework
TSW	Trade Skilled Workers
TUOS	Transmission Use of System
UPS	Uninterruptible Power Supply
URD	Underground Residential Development
URF	Utility Regulators Forum
US	United States
VLC	Voluntary Load Control
VSP	Voluntary Separation Package
VICTORIAN ESC	Essential Services Commission, Victoria
WACC	Weighted Average Cost of Capital
WTP	Willingness to Pay

EXECUTIVE SUMMARY

The South Australian electricity supply industry is comprised of four distinct sectors: generation, transmission, distribution (transporting electricity to end-use customers) and retailing (sale of electricity to end use customers). There is competition in the generation and retail elements of the industry, while the transmission and distribution elements are generally considered to be natural monopolies.

The focus of this draft price determination is on the electricity distribution network owned and operated by ETSA Utilities.

As ETSA Utilities is the sole provider of these distribution services in South Australia, it has the potential to exercise monopoly power. Being a monopoly provider within a particular area is a common position for energy utilities worldwide, given the high costs of building and operating the network. Such high fixed costs mean that one supplier is able to supply network services to a particular market at a lower cost than multiple suppliers.

As a consequence, where industries such as electricity distribution have been placed into private ownership or operation, or where a competitive energy market has been introduced, it is common for governments to establish independent economic regulatory bodies to oversee and regulate the price and service levels provided by those businesses.

In South Australia, the Essential Services Commission ("the Commission") has been established by the government to perform the economic regulation role in respect of the services provided by ETSA Utilities. In doing so, the Commission is required to ensure that price and service outcomes protect the interests of both users of distribution services and the provider of those services, ETSA Utilities.

The current price control regime that applies to ETSA Utilities is set out in the Electricity Pricing Order ("the EPO"). The EPO was issued by the Treasurer on 11 October 1999, pursuant to section 35B of the *Electricity Act 1996*, in anticipation of the sale/lease of ETSA Utilities Pty Ltd.

The initial five-year price controls established under the EPO cease to have direct effect on 30 June 2005, although the EPO continues to influence the manner in which the Commission must regulate distribution pricing. The Commission has power to make a new price determination to apply to distribution services and certain other services provided by ETSA Utilities to apply from 1 July 2005.

This is the first electricity distribution price determination made made by the Commission on the price control regime to apply to ETSA Utilities. This draft price determination sets out the Commission's reasons for the decisions on the prices and corresponding service levels to be provided by ETSA Utilities.

As a consequence of the proposed outcomes set out in this draft price determination, a number of the Commission's key regulatory documents, for example the Electricity Distribution Code, the Electricity Metering Code and the regulatory accounting guideline,

will be amended to make operational some of the proposed decisions made in this Review. That process will take place in early 2005.

As required by the legislative framework, the Commission has sought to balance the lowest possible price to customers with the provision of appropriate incentives to ETSA Utilities both to invest and operate efficiently and to deliver the outputs and services desired by network users.

Structure

As required by the Essential Services Commission Act 2002[1] ("the ESC Act"), the draft price determination comprises two parts:

Part A: The Statement of Reasons: This Part provides the context for the Review. It outlines the key issues, analysis, reasons and conclusions in relation to the establishment of the new price controls.

Part B: Price Determination: This Part sets out the detailed price controls, and the incentive and implementation mechanisms which will apply to the distribution services provided by ETSA Utilities over the 2005-2010 regulatory period.

Overall framework and approach

The regulatory approach adopted by the Commission to reset ETSA Utilities' prices is constrained by the EPO, which sets out a number of factors that the Commission must continue to apply in regulatory periods after the first regulatory period.

In particular, the EPO requires the Commission to utilise incentive based regulation adopting a CPI-X approach applied to average revenue[2].

The Commission has adopted a regulatory approach that is similar to that currently applied under the EPO. ETSA Utilities' prices have been determined by reference to a set of external capital and operating expenditure benchmarks. The average revenue control is based on the maximum revenue that ETSA Utilities can recover per unit of sales.

There is an inherent trade-off between prices and service levels, which is referred to by the Commission as the regulatory bargain. In developing this draft price determination, the Commission has necessarily considered prices and service as a package. Prices have been established which are commensurate with the levels of service, reliability and quality that ETSA Utilities is expected to provide.

The Commission, in reviewing the price controls for the 2005-2010 regulatory period, has used a "building-block" approach. The building block approach has been used to establish the average revenue controls on the basis of forward looking revenue benchmarks, which are determined as the sum of:

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1 ESC Act 2002, s 26

2 EPO, clause 7.2(a)

- the operating expenditures that an efficient distributor would need to incur over the regulatory period;
- an amount reflecting depreciation on the regulatory asset base over the regulatory period;
- a return on the regulatory asset base; and
- an efficiency carryover amount.

The average revenue control determined by the Commission for 2005/06 is then adjusted annually for inflation (the change in the consumer price index (CPI)) less an X factor. This is referred to as CPI-X regulation.

Key outcomes and impacts

There are several significant outcomes arising from this draft price determination:

Distribution Tariffs

The draft price determination results in an initial one off adjustment of prices on 1 July 2005, which is a reduction in the average revenue that ETSA Utilities can recover across all customer groups of 7%. Following this, the average revenue will change by the CPI less an X factor of 1.3% for each year commencing 1 July 2006.

Once this yearly adjustment has been made to the average revenue controls, ETSA Utilities is required to determine its distribution tariffs, such that they recover no more revenue than allowed for by this draft price determination.

The draft price determination proposes a tariff rebalancing constraint of CPI+2.5% for all tariff components, together with an additional constraint that the supply charge of a residential distribution tariff cannot increase by more than $5 per year. The primary purpose of the rebalancing control is to prevent large changes in tariffs for specific groups of customers, while providing some flexibility for the adjustment of distribution tariffs over time.

Regulatory Rate of Return

The draft price determination reduces the allowable regulatory rate of return from the present level of 8.26% (pre-tax real), as provided in the EPO for the current regulatory period, to 6.81% (pre-tax real) for the 2005-2010 regulatory period.

Service Standards

In determining the distribution prices that will apply in the 2005-2010 regulatory period, the Commission has considered the levels of service that ETSA Utilities should be required to meet during the regulatory period.

The development of a service standard framework has been guided by the outcomes of a customer survey conducted in 2002 on behalf of the Commission,

which provided information on those aspects of service most valued by customers and their willingness to pay for these services.

Among its key findings, the survey revealed that around 85% of customers were satisfied with their existing level of service and were generally unwilling to pay for improvements in these levels. The findings did not support the funding of initiatives to achieve improvements in average service levels across the entire customer base but rather indicated that customers with good service are willing to pay to improve the service to poorly served customers.

The Commission has developed a framework that focuses on providing an incentive to improve the reliability performance experienced by the approximately 15% of worst served customers, while maintaining average reliability levels for all customers on a regional basis at historical levels.

The components that make up the proposed new framework are broadly similar to those that exist under the current Electricity Distribution Code. The three components comprise:

Average service standards that ETSA Utilities is required to use its best endeavours to provide to customers. Network reliability standards, which are applied to seven different regions of the network, measure total minutes off supply and interruption frequency.

Average service standards also cover aspects of quality of supply, time to restore supply after and interruption, and customer service performance.

Service Incentive (SI) scheme, which provides ETSA Utilities with a financial incentive to improve certain aspects of service to the worst served distribution customers over time.

Guaranteed Service Level (GSL) scheme, which requires ETSA Utilities to directly compensate customers who receive service that is worse than a pre-determined level. Customers who experience more than 9 interruptions per annum or 12 hours off supply for any single interruption will receive an $80 payment. An increased level of payment is to apply if the reliability worsens from this level.

Capital and Operating Expenditure

This draft price determination has determined ETSA Utilities' aggregate annual revenue requirement using a building block approach. The building block approach requires the Commission to determine the level of expenditure that a distributor acting efficiently would require in order to provide prescribed distribution services in the regulatory period.

ETSA Utilities provided the Commission with its proposed expenditure requirements for the 2005-2010 regulatory period. It submitted that while it had been able to keep within the current expenditure allowances, these allowances are amongst the lowest in Australia and are unsustainable over the long term if service

levels are to be maintained. It proposed a 60% increase in capital expenditure and a 45% increase in operating expenditure compared to current levels.

In coming to its determination on appropriate expenditure allowances for the 2005-2010 regulatory period, the Commission has paid careful attention to ETSA Utilities' submission, sought submissions from interested parties and engaged independent experts to assist it to review ETSA Utilities' proposal.

In addition, the Commission established a consumer advisory committee working group (CACWG) which met monthly from June to October. The Working Group worked with Commission staff in reviewing a number of matters which had capital and operating cost implications relating to ETSA Utilities' submission.

The Commission has determined that a real increase in capital and operating expenditure above current levels is required for ETSA Utilities to provide prescribed distribution services, recognising the importance of ensuring on-going maintenance of, and investment in, the distribution network and the need to replace aging infrastructure.

Based on an assumed annual 3% growth in peak demand and an annual 1.7% growth in energy sales each year, the Commission's draft decision is to allow a total capital expenditure benchmark of $723 million (which is 37% higher than current levels and 15% lower than that proposed by ETSA Utilities); and a total operating expenditure benchmark of $630 million (which is 22% higher than current levels and 16% lower than that proposed by ETSA Utilities).

	CAPITAL EXPENDITURE ($000'S IN MARCH 04 PRICES)	OPERATING EXPENDITURE ($000'S IN MARCH 04 PRICES)
Current expenditure	$535 million	$515 million
ETSA Submission	$850 million	$746 million
Commission Draft Decision	**$723 million**	**$630 million**

The expenditure benchmarks proposed by the Commission do not dictate the actual amount of expenditure that ETSA Utilities must incur or how ETSA Utilities should direct its expenditure.

ETSA Utilities is responsible for managing its daily network operations and maintaining supply reliability and services to customers, and it must decide appropriate expenditures to meet its obligations and to maintain the long-term integrity of the network. The incentive regulatory regime actually is intended to encourage ETSA Utilities to adopt innovative practices which allow it to spend below the benchmark levels whilst maintaining service levels.

Safety and Environmental Expenditure & Undergrounding of Powerlines

The Commission considers addressing environmental, worker, technical and public safety issues to be highly important and this draft price determination allows significant increases in safety and environmental expenditure over current levels and proposes a regime to monitor the expenditure of these allocated funds.

Funding of the undergrounding of powerlines is maintained at current levels of around $6 million per year in real terms.

Demand Management

Peak demand is a major driver of increased network capital investment. However, peak capacity is only needed for a few days each year and is under-utilised for the rest of the year, resulting in high costs to customers.

The draft price determination makes specific provision for ETSA Utilities to commit $20 million over the five year regulatory period to trial a number of demand management initiatives which may result in less need for peak-driven network expansion.

The range of initiatives to be trialled include:

- "power factor" improvements in business and manufacturing premises;
- trials of Voluntary Load Curtailment (VLC) programmes for large customers;
- Direct Load Control (DLC) of domestic equipment such as air-conditioners and pool pumps;
- use of standby generation, and
- the use of incentives for customers to reduce demand at times of peak demand.

Interval Meters

The Commission has determined that it is not appropriate to mandate a broad roll out of interval meters to all customers, due to the high cost of such a roll out (and the resultant impact on prices) relative to the Commission's view of the benefits.

Summary

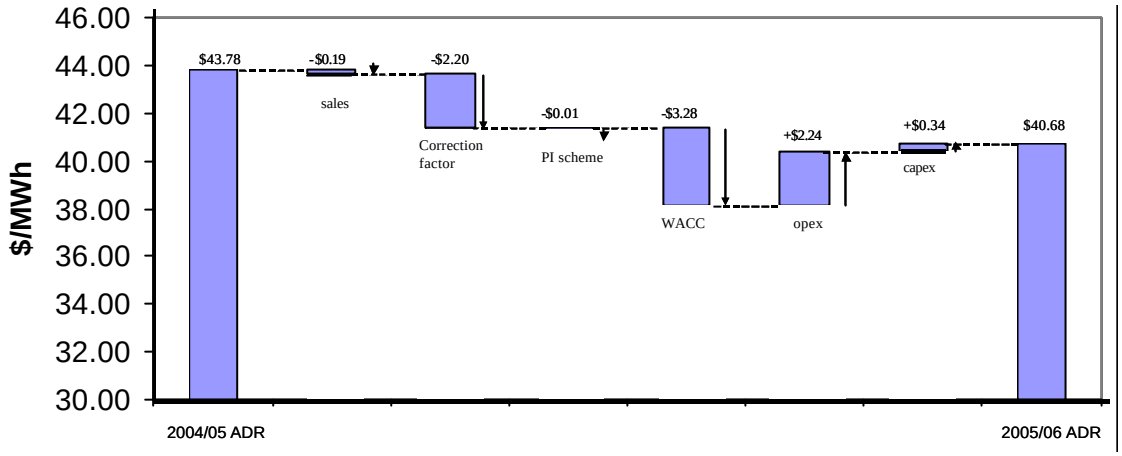
Overall, this draft price determination has reduced the average revenue control from $43.78/MWh in 2004/05 to $40.68/MWh in 2005/06, which represents an initial reduction in average revenue of $3.10/MWh or 7%.

A number of factors contributed to this change in average revenue, including:

- A reduction in the regulatory return on assets, which accounted for a reduction in average revenue of $3.28/MWh;

- the existence of a correction factor in the 2004/05 average revenue, which accounted for a reduction of $2.20/MWh;[3]
- the Commission's decision to increase the capital and operating expenditure benchmarks, which increased the average revenue by $2.58/MWh;
- the change in sales forecasts between 2004/05 and 2005/06 and the performance incentive scheme revenue earned in 2004/05 (in respect of ETSA Utilities' service level performance in 2003/04), which led to a decrease of $0.20/MWh.

The factors contributing to the change in average revenue between 2004/05 and 2005/06 are shown in the figure below.



The Commission seeks comment on this draft price determination by 11 February 2005, and intends to release a final determination in late March 2005.

[3] This correction factor under the EPO allows ETSA Utilities to recover any over or under recovery of revenue resulting from proportional shifts in sales.

1 INTRODUCTION

1.1 The Electricity Distribution Price Determination

The Essential Services Commission ("the Commission") has been established by the South Australian Parliament, through the enactment of the *Essential Services Commission Act 2002* ("the ESC Act"), as the economic regulator of certain essential services in South Australia.

Amongst the essential services in respect of which the Commission has regulatory responsibility are the electricity distribution services provided by ETSA Utilities.[4] Under the licensing provisions of the *Electricity Act 1996* ("the Electricity Act"), the Commission authorises ETSA Utilities to provide electricity distribution services and, in doing so, requires it to provide those services to certain standards. ETSA Utilities is entitled to charge customers in exchange for the provision of services at those standards. In 2003/04, ETSA Utilities' revenues for prescribed electricity distribution services were $589 million.[5]

As the distribution of electricity is generally regarded to be a monopoly service,[6] and given the financial significance of electricity distribution charges, a regulatory pricing regime has been established in respect of these services.

At the national level, the principles and objectives of the regime are embodied within the National Electricity Code ("the NEC"). These principles and objectives provide economic regulators with guidance as to the appropriate way in which prices ought to be regulated so as to reflect the service standards set for, and investments by, electricity distributors such as ETSA Utilities.

In South Australia, price controls for electricity distribution services were established for the period 11 October 1999 to 30 June 2005 under the Electricity Pricing Order ("the EPO") issued by the then Treasurer in accordance with section 35B of the Electricity Act.

The terms of the EPO are consistent with the principles and objectives of the NEC and, as well as regulating charges for electricity distribution services, it provides additional guidance to the Commission as to how it must regulate charges for electricity distribution services in the future in relation to certain matters.[7]

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4 ETSA Utilities is a partnership of CKI Utilities Development Limited (ARBN 090 718 880), HEI Utilities Development Limited (ARBN 090 718 951), CKI Utilities Holdings Limited (ARBN 091 142 380), HEI Utilities Holdings Limited (ARBN 091 142 362) and CKI/HEI Utilities Distribution Limited (ARBN 091 143 038) and is authorised to operate an electricity distribution network by an electricity distribution licence issued by the Commission under section 17(1) of the *Electricity Act 1996*.

5 *2003-04 Annual Performance Report, Performance of Regulated Electricity Businesses*, Essential Services Commission, November 2004, pp. 71-81 (http://www.escosa.sa.gov.au/resources/documents/041124-O-ELEC_AnnualPerformanceReport_2003-04.pdf).

6 As it is not economically viable to replicate the network of poles and wires through which electricity is distributed.

7 See generally Chapter 7 of the EPO.

From 1 July 2005, the EPO will no longer regulate electricity distribution prices directly[8] and the Commission is required, by both the EPO and the NEC, to establish new price controls to apply for a period of five years from that date through a price determination made under the ESC Act 2002.[9]

The price determination process represents the Commission's first opportunity to consider and review the prices charged by ETSA Utilities for the provision of electricity distribution services.

1.1.1 The Consultation Process

In anticipation of making a price determination in March 2005, the Commission has engaged in an extended period of public and industry consultation since early 2002. The purpose of engaging in consultation was to provide the Commission with the benefit of a broad range of views on the nature and form of new price controls (though recognising that in many areas the Commission has little or no ability to deviate from the obligations placed upon it by the NEC and the EPO).

The Commission's consultation included the release of Issues and Discussion Papers for stakeholder comment, followed by the formulation of Working Conclusions.

These Working Conclusions were aimed at providing some certainty to stakeholders (although they could not provide absolute certainty, as the Commission retains the right to amend its position up until the time it makes its formal price determination in March 2005) as to the Commission's position on various issues arising in relation to the establishment of new price controls.

The timeline for the consultation process was as set out in Table 1.1.

Table 1.1: Written Consultation Process

PAPERS	DRAFT / DISCUSSION PAPER	WORKING CONCLUSIONS
PHASE 1		
Price review framework	Completed – March 2002	Completed – October 2002
Service standards framework	Completed – February 2002	Completed – July 2002
PHASE 2		
Survey of customer preferences	Completed- April 2003	
Efficiency measurement and continuous incentives	Completed – December 2002	Completed – April 2003
Defining prescribed and excluded services	Completed – April 2003	Completed – June 2004
Service standards	Completed – April 2003	Completed – June 2004
Rate of return and asset valuation	Completed – August 2003	**Carried forward to draft price determination**

8 The EPO will continue to apply in other areas, such as the country equalisation scheme and retailer of last resort requirements.

9 The five year period is specified through the definition of *subsequent regulatory period* in Chapter 9 of the EPO to mean the period of 5 years from 30 June 2005. Unlike much of the EPO, Chapter 9 of the EPO is not stated to expire in clause 1.8 and therefore has effect and application until such time as the EPO is amended or revoked under section 35B of the Electricity Act.

In addition, through early 2003 the Commission undertook a number of public meetings throughout metropolitan and regional South Australia, explaining the price determination process and seeking community involvement and input into the issues to be decided. The meetings were designed to inform and educate the general community about those issues so as to encourage greater community participation in electricity distribution pricing for the 2005-2010 regulatory period.

As a part of establishing appropriate levels of service delivery, the Commission also undertook an extensive survey of South Australia consumer preferences for service quality and prices. The outcomes of that survey are set out in more detail in Chapter 3.

1.1.2 This Draft Price Determination

Following the completion of the Commission's preparatory public consultation process, it has embarked on a process of preparing a draft price determination, as permitted under section 26(1) of the ESC Act.

The Commission is not obliged to prepare a draft determination; however, it considers that it is important and appropriate that it does so in order to provide all stakeholders with the opportunity to consider and review the outcomes of the price determination process prior to the making of a formal price determination in March 2005.

This draft price determination is comprised of two Parts. Part A contains a statement of reasons for the draft price determination and a summary of the information on which that determination has been based. Part B contains the draft price determination, which sets out the form of price control which will apply to the distribution services provided by ETSA Utilities during the period 1 July 2005 to 30 June 2010.

The draft price determination has been prepared under Part 3 of the ESC Act, as authorised by sections 35A(1)(a), (b) and (c) of the Electricity Act. In doing so, the Commission has had regard to all relevant factors, principles and objectives as specified in the NEC, the EPO, the Electricity Act and the ESC Act, as well as, where appropriate and permitted, other factors which the Commission has considered to be relevant.[10] The Commission has also had the benefit of, and has carefully considered, all submissions, information and other documents provided by stakeholders and consultants during the consultative process.

The price determination process is not a determination by the Commission of a proposal put forward by ETSA Utilities, nor it is a process involving the Commission deciding between two competing cases (for example, ETSA Utilities and distribution network users). What has been established as the Commission's role

[10] See *Essential Services Commission Act 2002*, section 25(4)(h).

under the Electricity Act and the ESC Act is a process whereby the Commission is required to consider all relevant evidence available to it, and have regard to all relevant factors and objectives, and thereafter to make a price determination which it considers best meets those factors and objectives in light of the evidence. In this sense, while the Commission's decision is informed by all representations made to it, its draft price determination is not a judgment on those representations: it is the Commission's considered position as to the appropriate form of regulation and price control to be applied during the 2005-2010 regulatory period.

1.2 Legislative Framework

As a statutory authority, the Commission is required to act within the legislative framework established by the Parliament and, moreover, is able to exercise only those powers and functions which have been given to it by Parliament.

1.2.1 The Functions and Objectives of the Commission

The scope of the Commission's powers (referred to as its functions) is set out in section 5 of the ESC Act:

5. *(1) The Commission has the following functions:*

   (a) *to regulate prices and perform licensing and other functions under relevant industry regulation Acts;*

   (b) *to monitor and enforce compliance with and promote improvement in standards and conditions of service and supply under relevant industry regulation Acts;*

   (c) to make, monitor the operation of, and review from time to time, codes and rules relating to the conduct or operations of a regulated industry or regulated entities;

   (d) to provide and require consumer consultation processes in regulated industries and to assist consumers and others with information and other services;

   (e) to advise the Minister on matters relating to the economic regulation of regulated industries, including reliability issues and service standards;

   (f) to advise the Minister on any matter referred by the Minister;

   (g) to administer this Act;

   (h) to perform functions assigned to the Commission under this or any other Act;

   (i) in appropriate cases, to prosecute offences against this Act or a relevant industry regulation Act.[11]

These functions are broad in nature. Given that the grant of power bestowed by Parliament upon the Commission is broad, the Parliament has also provided guidance as to how the functions are to be exercised, by noting certain objectives or factors to which the Commission must have regard in performance of its section 5 functions.

[11] It is to be noted that while the list of functions set out in this section of the ESC Act is exhaustive, it does call up other Acts as a source of specific functions.

These objectives are set out in section 6 of the ESC Act:

6. (1) In performing the Commission's functions, the Commission must—

(a) have as its primary objective protection of the long term interests of South Australian consumers with respect to the price, quality and reliability of essential services; and

(b) at the same time, have regard to the need to—

(i) promote competitive and fair market conduct; and

(ii) prevent misuse of monopoly or market power; and

(iii) facilitate entry into relevant markets; and

(iv) promote economic efficiency; and

(v) ensure consumers benefit from competition and efficiency; and

(vi) facilitate maintenance of the financial viability of regulated industries and the incentive for long term investment; and

(vii) promote consistency in regulation with other jurisdictions.

The distinction between the functions and the objectives of the Commission is that the functions are a list of the things which the Commission is able to do, while the objectives inform or moderate the carrying out of those functions by the Commission.

1.2.2 Price regulation and the Electricity Act 1996

Amongst the functions set out in section 5 of the ESC Act is the regulation of prices under relevant industry regulation Acts.[12]

The Electricity Act is a relevant industry regulation Act which assigns a function to the Commission in addition to its functions and powers under the ESC Act.[13] It expressly provides the Commission with the power to undertake price regulation functions in accordance with its terms.[14]

Division 2A of the Electricity Act contains a price regulation scheme for the electricity supply industry. Section 35A(1) specifies the scope of the Commission's price regulation role under that scheme. The section provides that:

35A. *(1) The Commission may make a determination under the Essential Services Commission Act 2002 regulating prices, conditions relating to prices and price-fixing factors for:*

(a) the … supply of electricity to small customers;

(b) *the sale and supply of electricity to customers of another electricity entity as required by a retailer of last resort requirement…;*

(c) *subject to the National Electricity (South Australia) Law and the National Electricity Code – network services;*

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12 *Essential Services Commission Act 2002*, section 5(1)(a).

13 *Electricity Act 1996*, section 14D.

14 *Electricity Act 1996*, section 6A(1)(a).

In exercising these functions under section 35A(1) of the Electricity Act, the Commission must utilise the price regulation scheme contained in Part 3 (sections 25 to 27) of the ESC Act. It is also clear from the terms of the grant of power that the exercise of that power is subject to the requirements of the National Electricity (South Australia) Law and the NEC. The Commission notes that, as discussed further below, section 35B(13) of the Electricity Act additionally restricts the Commission's exercise of power to the extent that such a restriction is specified in the EPO.

1.2.3 Price determination scheme under the Essential Services Commission Act 2002

Sections 25(1) and 25(2) of the ESC Act have a combined effect of empowering the Commission to make price determinations where authorised to do so by relevant industry regulation Acts, such as the Electricity Act.

Section 25(3) of the ESC Act provides that the Commission may make a price determination that regulates prices, conditions relating to prices or price fixing factors in any manner it considers appropriate. Examples of the manner in which a price determination might operate are stated to include:

- fixing a price or the rate of increase or decrease in a price;
- fixing a maximum price or maximum rate of increase or minimum rate of decrease in a maximum price;
- fixing an average price for specified goods or services or an average rate of increase or decrease in an average price;
- specifying pricing policies or principles;
- specifying an amount determined by reference to a general price index, the cost of production, a rate of return on assets employed or any other specified factor;
- specifying an amount determined by reference to quantity, location, period or other specified factor relevant to the supply of goods or services;
- fixing a maximum average revenue, or maximum rate of increase or minimum rate of decrease in maximum average revenue, in relation to specified goods or services; and
- monitoring the price levels of specified goods and services.

The examples given are not exhaustive, and the Commission may make a price determination to operate in a manner it considers appropriate, subject to the imperatives of sections 35A(1)(c) and 35B(13) of the Electricity Act, the requirements of the National Electricity (South Australia) Law, the NEC and the EPO.

1.2.4 Matters to which the Commission must have regard

Having identified the source and the nature of the function given to the Commission in relation to the Price Determination, there are clearly a number of matters to which the Commission must have regard in the performance of that function.

Essential Services Commission Act 2002

As well as the general factors set out in section 6 of the ESC Act, section 25(4) of the ESC Act specifies particular factors to which the Commission must have regard when exercising its price determination function:

- the particular circumstances of the regulated industry and the goods and services for which the determination is being made;
- the costs of making, producing or supplying the goods or services;
- the costs of complying with the laws or regulatory requirements;
- the return on assets in the regulated industry;
- any relevant interstate and international benchmarks for prices, costs and return on assets in comparable industries;
- the financial implications of the determination;
- any factors specified by a relevant industry regulation Act or by regulation under the Act; and
- any other factors that the Commission considers relevant.

Section 25(4) of the ESC Act provides that these factors are to be given regard in addition to the general factors out in section 6 (set out at section 1.2.1 above) of that Act.

Two additional statutory imperatives are given to the Commission in section 25(5) of the ESC Act: wherever possible, it must ensure that the costs of regulation do not exceed the benefits; and any decision must take into account and clearly articulate any trade-off between costs and service standards.[15]

Section 25(6) of the ESC Act provides that subsections 25(3), 25(4) and 25(5) have effect in relation to a regulated industry subject to the provisions of the relevant industry regulation Act for that industry.

[15] *Essential Services Commission Act 2002*, section 25(5).

Electricity Act 1996

The Electricity Act, an industry regulation Act for the purposes of the ESC Act, contains a number of objectives in section 3. As a general principle, the objectives of an Act are designed to assist in understanding the manner in which the Act is to be interpreted. The objectives of the Electricity Act are:

- To promote efficiency and competition in the electricity supply industry;
- To promote the establishment and maintenance of a safe and efficient system of electricity generation, transmission, distribution and supply; and
- To establish and enforce proper standards of safety, reliability and quality in the electricity supply industry; and
- To protect the interests of consumers of electricity.

Division 2A of the Electricity Act, which deals with price regulation, also sets out a number of matters (outside of section 35A(1)(c)) which need to be considered in relation to this draft price determination.

Section 35A(2) provides that in making a price determination the Commission must (in addition to having regard to the factors specified in the ESC Act) have regard to the principle that the prices charged to small customers for network services in relation to distribution networks should be at the same rates for all customers regardless of their location.

Importantly, the Electricity Act also provides for the making of an EPO by the Treasurer (meaning that the EPO is an instrument under the Electricity Act). An EPO has been made and contains various elements which will have an impact upon this price determination.

Initial Electricity Pricing Order

Section 35B of the Electricity Act provides that the Treasurer may issue an EPO in relation to network services, subject to the National Electricity (South Australia) Law and the NEC.

The then Treasurer issued an EPO on 11 October 1999, setting out, amongst other things, the tariffs applicable to ETSA Utilities for the initial regulatory period.

Section 35B(12) of the Electricity Act provides that the Commission must perform functions contemplated to be performed by it under the EPO. Section 35B(13) provides that the Commission's powers under Division 2A (the price regulation division of the Electricity Act) and the ESC Act are restricted to the extent specified in the EPO.

There are a number of principles which the EPO requires the Commission to apply to regulatory periods after the expiry of the initial EPO.

- For the 2005-2010 regulatory period:
  - the Commission must adopt a CPI-X approach (applied to average revenue per MWh) with a single X factor to apply for the whole period;
  - the rate of return must be determined in accordance with Schedule 10 and prices must be adjusted in a single change to account for the new rate of return;
  - the Commission must have regard to the need to offer a continuous incentive to improve efficiencies in operations, capital expenditure and utilisation of existing assets. ETSA Utilities is to keep the benefits of any efficiencies gained (over and above the X factor) during the first regulatory period, before sharing the gains with consumers by way of reduced tariffs in subsequent regulatory periods.
- For the 2005-2010 and 2010-2015 regulatory periods, the Commission must use the asset base set out in Schedule 9 adjusted to account for inflation, depreciation, capital expenditure and disposals in the ordinary course of business, as well as other assets necessary to enable ETSA Utilities to provide prescribed distribution services, including easements;
- For all regulatory periods:
  - The costs of undergrounding required to be performed in accordance with the Electricity Act must be included in the rate base at the efficient cost of undergrounding, and an allowance must be made on an annual basis for the written down value of overhead lines and poles removed in the previous year;
  - ETSA Utilities must be adequately compensated to the extent it is required to keep country lines in service; and
  - State-wide Distribution use of System (DUOS) must be maintained.

The effect of the terms of the EPO on the price determination is that where the EPO provides that certain treatments of issues will occur in subsequent regulatory periods, the Commission's general powers under the ESC Act and Electricity Act are restricted to that extent. The effect of the EPO's provisions needs to be assessed by the Commission on an issue-by-issue basis.

It is to be noted that, although the EPO will no longer directly regulate the pricing of distribution services provided by ETSA Utilities after 30 June 2005, it will continue in existence even after that time. This will occur in two ways; the first being the continued control which the EPO will place over the economic regulator of electricity distribution service pricing in South Australia as described above; the second being the EPO's continued regulation of a number of matters, including the value of the asset base, the Country Equalisation Scheme[16] and charging for

[16] EPO, clause 8.2.

the sale and supply of electricity by ETSA Utilities in accordance with its retailer of last resort licence obligation.[17]

The National Electricity (SA) Law and the National Electricity Code

The National Electricity (SA) Law contains, as a schedule, the NEC. The general tenor of the regulatory scheme for the liberalised electricity market in Australia is that regulation of network businesses will be undertaken in accordance with the principles of the NEC.

This is reflected in the words of the Electricity Act (in relation to both the Treasurer's and the Commission's powers to make price determinations in relation to distribution network services) and in the EPO. Clause 1.11 of the EPO provides that:

> *The terms of the Code (including the terms of any applicable derogations) will prevail over the terms of this Order to the extent of any necessary inconsistency. It is intended that the Regulator interpret and apply the Code and this Order in such a manner as to avoid inconsistency wherever possible.*

The Commission has been advised that there are no necessary inconsistencies between the EPO and the NEC which would require it to abandon elements of the EPO (as set out above).

Chapter 6 of the NEC sets out the principles which relate to the regulation of network pricing for transmission and distribution networks. Of relevance to a price determination for ETSA Utilities, Parts D and E of Chapter 6 are specific to distribution network pricing.

The Commission must, therefore, make any price determination in relation to ETSA Utilities' provision of distribution network services in accordance with the NEC.

1.2.5 Working within the legislative price regulation scheme

There are a number of principles arising from the legislative price regulation scheme which bind the Commission in its price determination process:

- The price determination is to be made under the ESC Act as authorised by the Electricity Act;
- Due to the operations of section 35B(13) of the Electricity Act, the Commission must comply with the provisions of the EPO (in particular, clause 7.2). To this extent, relevant provisions of the EPO have paramountcy over the ESC Act and the Electricity Act;

[17] The retailer of last resort obligation is a mandatory licence condition placed on ETSA Utilities' electricity distribution licence under section 24(1)(n)(ix) of the Electricity Act. The relevant licence condition is clause 19 of ETSA Utilities' licence (refer http://www.escosa.sa.gov.au/resources/documents/021216-D-EUOn-gridLicence-FRC.pdf).

- By reason of clause 1.11 of the EPO and sections 6A(4) and 35A(1)(c) of the Electricity Act, in the case that there is inconsistency between the provisions of the EPO and the NEC, relevant provisions of the NEC have paramountcy over the EPO;
- When considering "factors" to be taken into account in decision making, the factors are ranked in the following order:
  (a) The NEC;
  (b) The EPO;
  (c) Sections 6A(4) and 35A(2) of the Electricity Act (construed in light of section 3); and
  (d) Sections 6 and 25 of the ESC Act.

2 REGULATED SERVICES

2.1 Role of the Commission

Under clause 6.10.4 of the National Electricity Code (the NEC), the Commission is responsible for determining which of the distribution services provided by ETSA Utilities will be prescribed distribution services for the 2005-2010 regulatory period, and therefore subject to economic regulation in accordance with the principles set out in clause 6.10.5.

In making a decision as to which distribution services will be prescribed distribution services, the Commission is required to have regard to five matters:

- The principles for regulation of distribution service pricing set out in clause 6.10.3 of the NEC;
- The extent of effective competition for any given distribution service;
- Whether there is sufficient competition to warrant the application of a more light-handed form of regulation for any given distribution service;
- The effectiveness of the form of economic regulation specified by 6.10.5 of the NEC in achieving the efficiency objectives of clause 6.10.2 in relation to any given distribution service; and
- The form, if any, of the economic regulation specified by 6.10.5 of the NEC in relation to any given distribution service.[18]

Clause 6.10.4(b) of the NEC provides that any distribution services that are not determined by the Commission to be prescribed distribution services are deemed to be excluded distribution services. As excluded distribution services are required by the NEC to be subject to a “more” light-handed form of regulation than prescribed distribution services, the Commission must also determine which form of regulation is appropriate for this category.

One of the fundamental distinctions between prescribed distribution services and excluded distribution services is that excluded distribution services are generally provided at the request of, or for the benefit of, a specific customer, and so it is appropriate that the customer pay specifically for the provision of the service. In contrast, prescribed distribution services tend to be services provided by the distribution system to all customers or to customers of a broad class, and so it is appropriate that the costs of those services be recouped through distribution tariffs that are payable by customers in general or customers of that broad class.

The Commission notes that its powers to make price determinations under the Electricity Act are not limited to determinations in relation to network services. It also has the power (under sections 35A(1)(a) and (b)) to make price determinations in relation to the supply of

[18] NEC, clause 6.10.4(a).

electricity to small customers (those customers using less than 160MWh of electricity annually through a connection point) and in relation to the retailing of electricity to customers in accordance with a retailer of last resort licence requirement.

Therefore, the Commission proposes to establish a broader category of "service" to be known as "excluded services". This category will include, but not be limited to, "distribution services" (although obviously not prescribed distribution services). This will enable the Commission, through this price determination, to exercise other price determination powers by treating certain other services (for example retailer of last resort retailing) in a manner consistent with that in which non-prescribed distribution services are treated.

The scope of the Commission's draft decision as set out in the draft price determination in Part B in relation to regulated services therefore relates to:

- which services provided by ETSA Utilities will be regulated as "distribution services" for the 2005-2010 regulatory period;
- which distribution services will be regulated as "prescribed distribution services" in accordance with the principles set out in clause 6.10.5 of the NEC; and
- which distribution services, and which other services provided by ETSA Utilities in respect of which the Commission has pricing powers under the Electricity Act, will be regulated as "excluded services", and the form of regulation which will apply to those "excluded services".

2.2 Distribution Services

The EPO defines distribution services to mean any and all services provided by ETSA Utilities or a new distributor.[19] This very broad definition of distribution services extends beyond the notion of services provided in connection with ETSA Utilities' role as an operator of a distribution network. Arguably any services provided by ETSA Utilities would be caught by the definition.

When considering the on-going appropriateness of the current EPO definition, it is useful to consider the source of the Commission's authority to make a price determination in respect of ETSA Utilities. Relevantly, section 35A(1) of the Electricity Act provides such authority to the Commission in the following terms:

> **35A.** *(1) The Commission may make a determination under the Essential Services Commission Act 2002 regulating prices, conditions relating to prices and price-fixing factors for:*
>
> *(b) the … supply of electricity to small customers;*
>
> *(c) the sale … of electricity to customers of another electricity entity as required by a retailer of last resort requirement;*
>
> *(d) subject to the National Electricity (South Australia) Law and the National Electricity Code – network services.*

[19] EPO, clause 9.1.

It is clear from the terms of this section that the Commission's authority to make a price determination relates to the supply of electricity to small customers, retailer of last resort retailing and to network services provided by ETSA Utilities.

Distribution network services are defined in the Electricity Act to mean the distribution of electricity between electricity entities and from electricity entities to customers (including connection to a transmission or distribution network) and the control and regulation of the quality of electricity.[20] Clearly, therefore, the scope of the current EPO definition runs well beyond what is contemplated by the concept of distribution network services, covering any activities of ETSA Utilities whether or not related to the provision of distribution network services.

Accordingly, the Commission does not propose to adopt the current EPO definition of distribution services in its draft price determination.

In determining a new definition for distribution services the Commission's starting point is, necessarily, the NEC.[21] Distribution services are defined in the NEC as:

> *The services provided by a distribution system which are associated with the conveyance of electricity through the distribution system. Distribution services include entry services, distribution network use of system services, exit services and network services which are provided by part of a distribution system.*

Adoption of this definition as a starting point for the purposes of developing a definition to apply in the draft price determination satisfies the imperative of the Electricity Act that the price determination not be inconsistent with the NEC. It also meets the limitations on the grant of power to the Commission to make a price determination in relation to distribution network services as described above.

While the NEC definition will be the Commission's starting point, the Commission notes that there may be additions required to the definition to provide greater clarity in relation to certain services. In particular, the Commission is of the view that the nature of metering services requires greater clarification and that the retailer of last resort establishment services needs to be expressly included in the definition.

2.2.1 Metering services

The definition of metering services is somewhat problematic when regard is had to current relevant regulatory instruments; it is presently an undefined term in both the Electricity Pricing Order (EPO) and the NEC.

In terms of the EPO, the Commission is currently of the view that the metering work performed by ETSA Utilities is a distribution service by reason of the definition of

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20 *Electricity Act 1996*, section 4(1).

21 The *Electricity Act 1996* provides that the Commission is empowered to make a price determination for distribution network services "subject to" the NEC (section 35A(1)(c)) and must have regard to the provisions of the NEC in performing its price regulation function (section 6A(4)). It therefore follows that any definition adopted by the Commission should not be inconsistent with any definition existing in the NEC.

connection services in Schedule 2A of the EPO. It has concluded that "*the provision of capability at each distribution connection point… to deliver electricity to or take electricity from the connection point using the connection assets*" and "*the management, maintenance and operation of*" connection assets encompasses the provision of meters as well as meter reading, data processing and data management.[22] The obvious disadvantage of this is that it is not preferable to base a regulatory framework around inferential definitions; it would be better to adopt express definitions.

In terms of the NEC, while there is no express definition of metering services, matters relating to metering, and the rights, obligations, roles and responsibilities which attach to metering, are set out in Chapter 7. On that basis, it would be possible to infer that any services provided in accordance with Chapter 7 of the NEC are metering services.

The caveat on this definition in terms of the services which are provided by ETSA Utilities is that Chapter 7 of the NEC applies only to second tier loads.

The Joint Jurisdictional Regulators' Review of Metrology Procedures, which has proposed various changes to the regulatory scheme for metrology, defines metering services to comprise two functions:

- Meter provision services – the supply, installation and maintenance of metering installations; and
- Metering data services – the collection, processing and storage of, and provision of access to, energy data.

The Joint Jurisdictional Regulators' Review does not intend that these two functions be separated for purposes of contestability. What is therefore proposed to become more contestable is the overall function of "metering services" which would comprise these two roles.

The Commission accepts that the definition proposed by the Review is appropriate. It therefore proposes to adopt the following definitions for the price determination.

> ***metering services*** means *meter provision services* and *metering data services* .
>
> ***metering data services*** means the collection, processing and storage of, and provision of access to, *energy data*.
>
> ***meter provision services*** means the supply, installation and maintenance of *metering installations*.
>
> ***metering installation*** has the meaning given to that term in the *Code.*

[22] See EPO, Schedule 2.A, clause A.2.

The disaggregation of metering services into the categories of "prescribed distribution services" and "excluded services" is discussed below in sections 2.3 and 2.4 respectively.

2.2.2 Retailer of last resort establishment services

ETSA Utilities has an obligation under its distribution licence (a mandatory licence obligation which the Commission must impose by reason of the Electricity Act 1996[23]) to undertake the retailer of last resort role for electricity in South Australia. This service is currently deemed to be a prescribed distribution service.

The Government has recently extended the period for which ETSA Utilities must act as retailer of last resort (if required) from the end of 2004 to 30 June 2010.[24] Consequently, the possibility that it must act as the retailer of last resort will continue to be an issue for the 2005-2010 regulatory period for ETSA Utilities.

Retailer of last resort services relate to the sale of electricity to customers whose retailer stops selling electricity due to:

- the retailer's retail licence being suspended or cancelled; or
- the retailer's authority or right to acquire electricity from the market for wholesale trading in electricity being suspended or terminated; or
- the retailer ceasing to retail electricity in South Australia.

Provision of retailer of last resort services is a licence condition imposed upon ETSA Utilities. It is therefore appropriate that services required to enable ETSA Utilities to actually undertake the retailer of last resort obligation to retail electricity (such as establishment of IT systems) be included within the definition of distribution services.

The actual provision of retailer of last resort services is not, as such, network services. However, the Commission has the power under section 35A(1)(b) of the Electricity Act to make a price determination in respect of those services. In exercising that power, the Commission has decided that actual provision of retailer of last resort services will be "excluded services". This matter is discussed further in section 2.4.2 below.

2.2.3 Proposed definition of distribution services

While the Commission's position on an appropriate definition of distribution services is set out in detail in its draft price determination in Part B, for ease of reference the definition is reproduced below:

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23 *Electricity Act 1996*, section 23(1)(n)(ix).

24 *Electricity Act 1996*, section 23(3).

distribution services means all services:

a. provided by a *distribution system* which are associated with the conveyance of electricity through the *distribution system* including, without limitation, *connection services* and *network services*, *metering services*, *entry services*, *distribution network use of system services*, *exit services* and *network services* which are provided by part of a *distribution system*; and

b. associated with the establishment of *retailer of last resort* capabilities by *ETSA Utilities* in accordance with the requirements of its *distribution licence*.

2.3 Prescribed distribution services

Having defined distribution services for the purposes of the price determination, it is next necessary for the Commission to determine which of those distribution services will be prescribed distribution services.

The NEC defines prescribed distribution services to be:

> *Distribution services provided by distribution network assets or associated connection assets which are determined by the Jurisdictional Regulator as those which should be subject to economic regulation under clause 6.10.4(a).*

As noted above, the impact of defining a distribution service as prescribed is that the services become subject to economic regulation in accordance with the principles set out in clause 6.10.5 of the NEC.

Having regard to each of those matters, the Commission has formed a view that all distribution services provided by ETSA Utilities should be defined as prescribed distribution services, subject to the proviso that any individual distribution service deemed by the Commission to be excluded services will expressly fall outside of the definition.

Having reached this position, it is nevertheless appropriate that the Commission should discuss particular prescribed distribution services in some detail, as the status of these services will change to a degree in the price determination as compared with their current treatment under the EPO.

2.3.1 Metering services

Current Arrangements

As the local network service provider for the purposes of the NEC, ETSA Utilities has the function of providing metering services to second tier electricity customers[25] as the "responsible person". This function arises either through the acceptance by a retailer of a mandatory offer on the part of ETSA Utilities to

[25] A "second tier customer" is, in effect, a customer which purchases electricity through a connection point in South Australia from a person other than AGL SA.

perform this function (in relation to metering installations type 1 to 4[26]) or through the mandatory acceptance (by reason of a derogation to the NEC) by the retailer of such an offer (in relation to metering installations types 5, 6 and 7[27]).

It should be noted in relation to those second tier electricity customers with metering installations type 1 to 4 that the retailer does not have to accept ETSA Utilities' offer, and in those cases the retailer itself will provide the metering services as the responsible person.[28]

The provision of metering services to first tier customers is not regulated under the NEC.[29] The provision of such services to those customers is regulated by the Electricity Metering Code. Under that industry code there is no concept of retailers seeking offers to provide metering; ETSA Utilities is simply required to provide metering services to first tier electricity customers.

Nevertheless, the provision by ETSA Utilities of metering services to these first tier customers under the Electricity Metering Code is broadly on the same basis as the provision of those services under the NEC. For example, the consumption thresholds for installation of various metering types is the same for first and second tier customers, irrespective of the instrument under which metering services are provided to them.

Table 2.1: Metering Installations

CUSTOMER CONSUMPTION	PERMISSIBLE METER INSTALLATION TYPE [30]	METERING SERVICE PROVIDER	
		1ST TIER [31]	2ND TIER [32]
>1,000 GWh/a	Type 1	ETSA Utilities	Competitive choice of Responsible person
>=100 GWh/a to < =1,000 GWa/a	Type 2	ETSA Utilities	Competitive choice of Responsible person
>=750MWh/a to <100GWh/a	Type 3	ETSA Utilities	Competitive choice of Responsible person
<750 MWh/a	Type 4	ETSA Utilities	Competitive choice of Responsible person
<160MWh/a	Type 5	ETSA Utilities	ETSA Utilities (derogation)
<160MWh/a	Type 6	ETSA Utilities	ETSA Utilities (derogation)
<160MWh/a	Type 7	ETSA Utilities	ETSA Utilities (derogation)

26 NEC, clause 7.2.2.

27 NEC, clause 9.30.1.(3)(b).

28 NEC, clause 7.2.3.

29 NEC, clause 7.1.1.(b).

30 The consumption thresholds governing the type of metering installation which may be installed at a connection point are set by NEMMCO's Metrology Procedures in respect of metering installations Types 1-4 (available at www.nemmco.com.au) and by the Commission 's Metrology Procedures in respect of metering installations Types 5, 6 and 7 (available at www.escosa.sa.gov.au).

31 First tier metering services are regulated by the Electricity Metering Code, which ETSA Utilities provides exclusively.

32 Second tier metering services are regulated by the NEC. Metering services are generally contestable, however by reason of a derogation to the NEC, ETSA Utilities is exclusively responsible for providing metering installations types 5, 6 and 7.

Metering services for metering installations types 5, 6 and 7

As shown in Table 2.1, ETSA Utilities is a monopoly metering service provider in relation to metering installations types 5, 6 and 7, regardless of whether the customer is first or second tier.[33] On the other hand, there is a mixture of competition and a monopoly for the provision of metering installations types 1 to 4, based on whether a customer is a first tier (for whom ETSA Utilities has a monopoly on metering services under the Electricity Metering Code) or a second tier customer (where the ordinary rules of the NEC apply).

Future arrangements - classification of metering services for the 2005-2010 regulatory period

Given that there are some 750,000 "small" customers (those using less than 160MWh of electricity annually) with metering installations types 6 and 7, there are clear economies of scale which attach to the provision of metering services for this class of metering installation.

The Commission has therefore reached the view that the provision of metering services for meters which meet the requirements of metering installations types 6 and 7 (as defined in the NEC) to "small" customers will continue to be prescribed distribution services for the 2005-2010 regulatory period and that all such customers will pay for such a service through distribution use of system tariffs.

This means that the capital and operating costs associated with the supply, installation and maintenance of these metering installations and the collection, processing and storage of, and provision of access to, energy data recorded in them will be recovered from all "small" customers through distribution use of system charges during the 2005-2010 regulatory period.

Further, as is required by the EPO, all such metering installations currently in ETSA Utilities' regulated asset base will remain in the asset base and ETSA Utilities will be entitled to a return on and of those assets.[34]

On the other hand, as all "small" customers will be paying for the provision of a basic metering service (type 6 or 7), the Commission will define the provision of metering services in respect of customer meters meeting the requirements of metering installations types 1 to 5 to be excluded services, but only in terms of the incremental cost of those services over and above the costs of metering services for meters meeting the requirements of metering installations types 6 and 7.

In excluding meters meeting the requirements of a type 5 metering installation from prescribed distribution services, the Commission notes that the Joint

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33 For first tier customers this exclusivity arises under the Electricity Metering Code; for second tier customers it arises by way of the derogation to chapter 7 of the NEC set out in clause 9.30.1.

34 EPO, clause 7.2(e)(i).

Jurisdictional Regulators' Review has recommended that the provision of metering services with such meters should be a non-competitive service, provided solely by distributors.

The Commission is of the view that the degree of competition is only one criterion for establishing whether a distribution service should be categorised as a prescribed distribution service or an excluded service. Other criteria, such as efficiency, are equally relevant. In the case of metering services for meters meeting the requirements of a type 5 metering installation, the extent to which those meters are in service, or are likely to be brought into service, is low when compared with meters meeting the requirements of a type 6 metering installation. Further, the costs associated with metering services for meters meeting the requirements of a type 5 metering installation are significantly higher than for a type 6. The combination of these two factors would indicate that it is not efficient to "lose" the type 5 costs within the prescribed distribution service charges, particularly as meters meeting the requirements of a type 5 metering installation are more likely than not to be requested by a specific customer, rather than being a service sought by the majority of customers.

For these reasons, subject to the consideration of a special case below, it is only the provision of metering services for meters meeting the requirements of type 6 and 7 metering installations to "small" customers which will be prescribed distribution services.

For "large" customers (those using more than 160MWh of electricity per annum), the Commission will continue the current treatment of metering service provision, in that metering services provided to these customers will be excluded services.

Meter provision services for certain type 1 to 4 metering installations

There are two sub-categories of metering installations types 1 to 4 in relation to which meter provision services need to be included within prescribed distribution services rather than excluded services.

These two categories are legacies which have arisen under previous regulatory arrangements whereby ETSA Utilities was required in the ordinary course of business to provide metering installations types 1 to 4 as a prescribed distribution service, when that provision would otherwise have been an excluded or unregulated service.

The first of these relates to customers consuming between 160 and 750MWh per annum who had types 1 to 4 metering installations provided prior to 1 July 2000.

The second relates to customers consuming more than 750MWh per annum who had (or will have as at 30 June 2005) types 1 to 4 metering installations which were installed by ETSA Utilities pursuant to a mandatory condition of ETSA Utilities' distribution licence.

In terms of the first category, under the EPO the provision of metering installations to customers prior to 1 July 2000 was a prescribed distribution service.[35] This means that where such metering installations were installed before that date, the costs of meter provision have been recovered through distribution use of system charges and the metering assets provided are included within the regulated asset base. As a result, meter provision services (ie. capital expenditure costs) for this category of metering installations should remain as a prescribed distribution service under the price determination (although the on-going meter data services, - operating costs - will become excluded distribution services).

For the second category, ETSA Utilities' electricity distribution licence requires it to offer to install and maintain at its own cost metering installations that comply with the requirements of the NEC at all connection points where the customer's actual or estimated electricity consumption level at the connection point or an aggregated group of connection points equals or exceeds 750MWh per annum.[36] Again, the costs of meter provision services for these metering installations (which will be either types 1, 2 or 3) have already been recovered as a prescribed distribution service under the EPO and the assets have been included in the regulated asset base.

Aside from these two exceptional cases, the Commission's position is that only the provision of metering services for metering installations types 6 and 7 should be regulated as prescribed distribution services in the 2005-2010 regulatory period.

2.3.2 Retailer of last resort establishment services

In accordance with its approach of defining prescribed distribution services to be all distribution services other than those listed to be excluded services, the Commission will not define in any detailed way the establishment of retailer of last resort capabilities. Nevertheless, the Commission considers it appropriate to discuss briefly the extent to which retailer of last resort services will be included within the definition of prescribed distribution services.

While ETSA Utilities is only required to act as the retailer of last resort and sell electricity to customers following the occurrence of a retailer of last resort event, the Commission recognises that a provision needs to be made for any retailer of last resort on-going establishment costs that may be incurred by ETSA Utilities, regardless of whether such an event occurs in the future.

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35 EPO, Schedule 2A, clause A.2(a).

36 ETSA Utilities' electricity distribution licence, clause 27. A copy of the licence may be viewed on the Commission's website at www.escosa.sa.gov.au.

These costs include ongoing costs of maintaining processes and systems to ensure that ETSA Utilities is capable of acting as the retailer of last resort.[37] The Commission believes it is appropriate for these ongoing establishment costs to be shared between all distribution customers rather than be recovered only from the customers that are affected by a retailer of last resort event.

To achieve this outcome, the Commission will define retailer of last resort services in the price determination. It is to be noted that the provision of retailer of last resort functionality (that is, actually selling electricity to customers) will only be provided to customers of a failed retailer and, as a result, the costs of those services will be recovered from those customers as an excluded service. This latter aspect is dealt with in detail below.

2.3.3 Proposed definition of prescribed distribution services

The Commission proposes that prescribed distribution services will be defined as follows for the 2005-2010 regulatory period:

> ***prescribed distribution services*** means *distribution services* other than *excluded services*.

2.4 Excluded services

Given the Commission's position on the methodology by which prescribed distribution services are to be defined, it is necessary that the Commission consider carefully which distribution services are to be removed from that all-encompassing definition, therefore becoming excluded services and that each service is individually expressed to be an excluded service in the price determination.

It is also necessary that the Commission identify which services provided by ETSA Utilities in respect of which the Commission has pricing powers under the Electricity Act will be included within the definition of excluded services under the price determination.

The NEC defines excluded distribution services (which will form a subset, albeit a majority of excluded services) as:

> *Distribution services the costs of and revenue for which are excluded from the revenue cap or price cap which applies to prescribed distribution services.*[38]

Unlike the scheme for prescribed distribution services, the NEC does not set a detailed test for which distribution services should be classified as excluded distribution services. Clause 6.10.4(b) contains an exclusionary test for excluded distribution services, in the sense that any distribution services which are not prescribed distribution services are deemed to be excluded distribution services.

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37 Refer section 2.2.2 of "Electricity Industry Guideline No. 8 - Retailer Of Last Resort: Pricing And Charging Framework, Sep 2001" for a more detailed definition of ROLR establishment costs.

38 NEC, chapter 10.

To the extent that the NEC provides guidance on which distribution services should be categorised as excluded services, it simply notes that a common characteristic of such services is that a form of regulation which is more light-handed than that contemplated by clause 6.10.5 of the NEC is more appropriate. Arguably, given the more prescriptive test for prescribed distribution services set out in clause 6.10.4(a), an inverse of that test might also be adopted as a guide for the Commission in defining which distribution services should be excluded services.

The Commission has considered the current list of excluded distribution services as set out in Schedule B.2 of the EPO as a starting point for deriving a set of excluded services for the price determination. In doing so it notes that the majority of the current services will continue to be regulated as excluded services for the 2005-2010 regulatory period without change. There are, however, certain services which will change in scope and other services which will be added to the present list. These are discussed below.

2.4.1 Metering services

Following from the Commission's position in relation to the scope of prescribed metering services, the provision of metering services for meters meeting the requirements of metering installations types 1 to 5 (as defined in the NEC) to "small" customers will be excluded services to the incremental cost over and above the cost of provision of the prescribed metering services (for metering installations types 6 and 7). Further, the provision of all metering services to "large" customers will continue to be excluded services.

The general position for metering services under the NEC is that they should be provided on a competitive basis. As a result, for metering services provided to second tier customers for metering installations types 1 to 4, while the distributor is required to offer to provide a quote to supply those services in relation to a connection point, that quote does not have to be accepted if it is not the best price available. For instance, alternative independent metering providers and meter data agents might agree to provide a sub-contracted service to the retailer at an overall lower cost than has been quoted by the distributor. In such a case, the retailer itself is able to provide the metering services (using sub-contractors for the individual elements of the overall metering services) at the lower price.

It is the Commission's view that this regime ought to apply to first tier customers as well. In short, the Commission considers that whether a customer is first or second tier should not matter: the test for whether a service should be provided on a competitive or monopoly basis should be based on the nature of the service, not the characteristics of a customer.[39]

[39] This will require the Commission to make amendments to the Electricity Metering Code, which will be undertaken following the public release of this draft decision.

Further, as noted in section 2.3.1, the Commission has formed the view that while arguments have been made that metering services for meters meeting the requirements of a metering installation type 5 should not be competitive services, the Commission nevertheless considers that the appropriate form of regulation for this service is as an excluded service.

Overall, the Commission considers that the classification of metering services provided for meters meeting the requirements of metering installations types 1 to 5 should not require any consideration as to whether the customer is first or second tier: the provision of these services will be excluded services.

Exceptional cases

As discussed above the costs of meter provision services for metering installations types 1 to 4 installed prior to 1 July 2000 have already been recovered as a prescribed distribution service under the EPO and the Commission has determined that they will continue to be regulated in that way in the 2005-2010 regulatory period. In these cases, it would be inappropriate for ETSA Utilities to recover those costs again from customers. This means that the metering services charges which can be recovered by ETSA Utilities as charges for excluded services in relation to those metering installations should only reflect the recovery of any meter data service costs which ETSA Utilities incurs (that is to say, should only reflect operating costs and not include any capital expenditure elements).

Similarly, clause 27 of ETSA Utilities' electricity distribution licence requires it to offer to install and maintain, at its own cost, meters that comply with the requirements of the NEC at all connection points where the customer's actual or estimated electricity consumption level at the connection point or an aggregated group of connection points equals or exceeds 750MWh per annum. Again, the costs of meter provision services for these metering installations (which will be either types 1, 2 or 3) have already been recovered as a prescribed distribution service under the EPO and will continue to be so regulated going forward.

The metering services charges which can be recovered by ETSA Utilities in relation to those metering installations in place as at the commencement of the price determination should therefore only reflect the recovery of any meter data service costs (operating costs) which ETSA Utilities incurs.

It should be noted that the Commission intends to amend ETSA Utilities' distribution licence to remove the obligation to install and maintain metering installations for greater than 750MWh per annum customers from 1 July 2005. As a result, any metering installations for such customers installed after that date will be subject to the general rules for the provision of metering services for meters meeting the requirements of metering installations types 1 to 4, rather than the exceptional case described above.

2.4.2 Retailer of last resort

Actual retailer of last resort services (as opposed to retailer of last resort establishment services) are only provided if and when a retailer of last resort event occurs. It follows that they are provided only to those customers who are directly affected by the event (ie, customers of the failed retailer).

Section 35A(1)(b) of the Electricity Act provides the Commission with a price determination power in respect of these services. As these particular services are readily identifiable as customer-specific, the Commission is of the view that the services provided by ETSA Utilities to customers directly affected by a retailer of last resort event will therefore be considered as excluded services. The Commission is not considering these services to be "network services" for the purposes of this price determination.

It should also be noted that clause 8.1 of the EPO requires the Commission to set guidelines for the purpose of determining charges for acting as the retailer of last resort. The Commission has published such a guideline[40], which will continue to be used as the basis for determining retailer of last resort charges rather than the pricing principles outlined for excluded services. The Commission will continue to ensure that there is a neutral financial effect on ETSA Utilities arising from its obligation to be the retailer of last resort.

2.4.3 Street lighting services

Public street lighting is currently an excluded distribution service under Schedule 2.B of the EPO. These services are financially the most significant part of excluded distribution services, with the charges receiving much attention during the current regulatory period.

Public street lighting, as discussed here, does not refer to the service of transporting electricity through the distribution network for use in public street lights: this is a prescribed distribution service as part of the distribution use of system (DUOS). The current excluded service of public street lighting refers to the provision, operation and maintenance of street lighting assets.

There are three categories of public street lighting service:

- Where the service relates only to the operation and maintenance of public street lighting, it is referred to as customer lighting equipment rate (CLER) category and is an excluded distribution service.
- Where the service includes the provision of the assets, along with the maintenance and operation of those assets, the service is called street lighting use of system (SLUOS). The Commission believes that there is minimal scope for effective competition in the provision of SLUOS in the 2005-2010

[40] Electricity Industry Guideline No. 8 - Retailer Of Last Resort: Pricing And Charging Framework, Sep 2001.

regulatory period and, therefore, it had initially contemplated making SLUOS a prescribed distribution service. However, two of the major customers of SLUOS services, local Councils (represented by the Local Government Association of SA (LGA)) and Transport SA, have indicated a preference for SLUOS to remain an excluded service. One of the primary reasons for this preference is the view that both of these customers possess significant bargaining power, which they believe can be used to negotiate a competitive outcome for the provision of public lighting services. In light of this, the Commission would support a process of negotiation between the parties.

- A third public street lighting service also exists, called "energy only", where ETSA Utilities does not provide any of the above two services, and the primary service provider is the retailer who supplies the energy to the customer, who owns, operates and maintains its own street lighting assets.

The Commission proposes to retain standard public street lighting services (SLUOS) as an excluded service.

However, given the unique nature of public street lighting, and the experience of the Commission in regulating public street lighting services during the current regulatory period, it is proposed that the form of regulation that applies to this service be slightly different to that proposed for other excluded services.

2.4.4 Other excluded services

The Commission proposes that all other distribution services currently defined in Schedule 2.B of the EPO to be excluded distribution services will be defined as excluded services for the 2005-2010 regulatory period (see section 2.4.6 for detail of these services).

2.4.5 Adding new excluded services

The current list of excluded services is exhaustive and does not allow for any additions. This is different to the flexibility that exists in the NEC or that which existed in the EPO for Transmission services. The Commission is of the view that a flexibility clause should be included in the price determination for the 2005-2010 regulatory period as the provision of such flexibility in the price determination would allow for the clarification of services during the regulatory period if required.

Given the global definition of prescribed distribution service, incorporating such a clause will provide a safety net for ETSA Utilities. This is because if, for example, a distribution service is identified during a regulatory period that is clearly an excluded service (that is, for which ETSA Utilities has not been recovering its cost under the prescribed service charges), but is not listed in the excluded service schedule, the service would, by default, be classified as a prescribed distribution service. This would leave ETSA Utilities in a position where it could not seek to recover the cost of providing the service. The flexibility clause allows for such a

service to be added to the excluded distribution service list, should such a need arise, subject to the NEC's requirements.

2.4.6 Proposed definition of excluded services

The Commission proposes that excluded distribution services will be defined as follows for the 2005-2010 regulatory period:

> ***excluded distribution services*** means the services provided by *ETSA Utilities* set out in *Schedule 1* in respect of which the *Commission* has price determination powers under the *ESC Act* and a more "light handed" approach to price regulation is taken.

The list of excluded distribution services will be as follows, noting that further detail of the particular services will be more exhaustively defined under each heading in Part B:

- public street lighting;
- new and upgraded connection points;
- service standards (being the provision of network services or connection services to a standard higher than that required by the NEC, the Electricity Metering Code, the Electricity Distribution Code or other applicable laws);
- stand-by and temporary supply;
- distribution system (being the moving of mains, services or meters forming part of the *distribution system*, providing temporary disconnection, or temporary line insulation to accommodate extensions, re-design or re-development of any premises or otherwise as requested by a customer);
- metering services (to the extent described in this Chapter);
- provision of certain services in relation to the Electricity Distribution Code and Electricity Metering Code;
- embedded generation; and
- other miscellaneous services (including reference to regulated services requested by a customer or other party which the Commission considers is not reasonably contestable and accordingly should be regulated as an excluded service).

2.4.7 Form of regulation for excluded services

The NEC requires that the Commission select a form of regulation to apply to excluded distribution services. Further, the NEC requires that the form be a more light handed approach than that applying to prescribed distribution services. The Commission considers that, while it is bound to follow the NEC in respect of excluded services which fall into the category of excluded distribution services, it will also apply the same general principles to other services which it has classified as excluded services.

The term “light-handed” is not defined. However, it is generally taken to mean some combination of:

- less regulatory involvement;
- less, or more targeted, intervention;
- lower administrative and compliance activity; and/or
- a simpler structure of regulation.

This still allows for a considerable range of options.

In the Commission’s experience with other regimes (such as ports and rail), the most significant aspect of a more light handed approach is that it should allow for less regulatory involvement in the day to day aspects of the services being regulated.

A more light handed approach should also involve lower administrative or compliance costs, although the reduction may not be in direct proportion. Light handed regulation must still be effective – not every aspect of regulatory activity can be reduced for the sake of light-handedness.

Selecting the form of regulation requires the Commission to select a form that best meets the various legislative objectives – by best dealing with the characteristics of excluded services that warrant regulatory intervention.

Excluded services do not necessarily represent those services for which some competition exists, but could be provided for the benefit of a single consumer. Indeed, a number of current excluded distribution services are monopoly services, which are only provided by ETSA Utilities. However, there are a number of services that are contestable, including some for which effective competition may not exist.

Due to the varying competitive environments, different levels of regulatory intervention are warranted. Therefore, the Commission has sought a form of regulation that can:

- account for the varying degrees of competitive pressure to which excluded services will be subject;
- account for varying situations in which specific customers find themselves;
- operate effectively in the context of the services being regulated; while
- still address any market power concerns that might exist.

The Commission has taken the position that a pricing principles form of regulation will apply in the 2005-2010 regulatory period, as it provides some continuity with the current regime and is more likely to:

- be robust and flexible – able to respond to varying industry and market situations;

- be administratively effective – in that the effort is focussed on areas of particular issue (or dispute) rather than on all areas. Also, administrative costs are usually lower than more prescriptive regulatory forms such as price setting;
- provide ongoing incentives – in that the regulated service provider has a continuing obligation to comply with the principles; and
- better address the risk of over or under regulation – largely because different pricing principles can apply to suit the different services.

Pricing principles are also able to be designed so as to protect consumers from unreasonable price shocks. Although the Commission recognises cross subsidies exist within excluded services, unwinding these cross subsidies must be done over a period of time, rather than attempting to match costs for each service by moving prices in one instant to reflect the true cost of providing the service.

The pricing principles developed by the Commission seek to achieve a balance between unwinding cross subsidies and price shocks faced by consumers, by limiting the price change for any particular excluded service to no more than CPI+10% in any one year.

The pricing principles for all excluded services, except standard public lighting (SLUOS), will be as follows:

- Prices for excluded service are to be fair and reasonable, including consideration of:
  - cost reflectivity; and
  - overall profitability in relation to the total grouping of excluded distribution services
- The annual price movement for any particular excluded service should be restricted to no more than CPI+10% (unless otherwise approved by the Commission).
- For those excluded services for which effective competition exists, market determined prices will be considered as being fair and reasonable. However, ETSA Utilities must demonstrate the existence of effective competition to the Commission.
- ETSA Utilities will be required to publish its list of prices for excluded services annually.[41] For those services where this is not possible (because the charges would depend on a case-by-case basis) only the list of the services should be published.

[41] For the first year of the 2005-2010 regulatory period, the excluded distribution service charges need to be published no later than 1 July 2005. For the subsequent years, the charges must be published no later than the first working day in June of each year or 20 working days prior to the charges taking effect, whichever is earlier.

- In the event of a dispute, the Commission will determine whether an amount proposed to be charged by ETSA Utilities in respect of an excluded service complies with the pricing principles, as set out here.

The pricing principles for SLUOS, an excluded service, will be as follows:

- Prices for SLUOS are to be fair and reasonable. The price that will be considered by the Commission to be fair and reasonable during the next regulatory period will be:
  - any price that has been negotiated between ETSA Utilities and a customer (or a representative of a group of customers); or
  - in the event that agreement is not reached and there is a dispute, the price that is determined by the Commission.
- The annual price movement for any particular SLUOS service should be restricted to no more than CPI (unless otherwise approved by the Commission); and
- ETSA Utilities will be required to publish its list of prices for SLUOS annually.[42]

These principles will be set out by the Commission in a guideline to be released at the time of making the price determination in March 2005.

2.5 Profit sharing mechanism

As explained in this chapter, ETSA Utilities provides various services other than those that are prescribed. These include excluded services and those services that are not regulated by the Commission. In some cases, ETSA Utilities uses its prescribed (or regulated) asset base, such as its distribution poles and wires, as an input to provide these services.[43]

The average revenue controls set out in this draft price determination are based on a 100% allocation of the regulated asset base to the provision of prescribed distribution services. The Commission has decided to develop a mechanism that reduces the average revenue controls over the 2005-2010 period to allow distribution customers to share some of the benefits that ETSA Utilities earns by using regulated assets (that are funded by customers through distribution charges) to provide excluded and unregulated services.

Such a mechanism represents a proxy for cost allocation, as certain costs are allocated away from the prescribed distribution business. In making its decision, the Commission considered whether it would be more appropriate to discount prescribed distribution charges on the basis of the revenue or profit generated from providing the other services using the regulated asset base.

A revenue sharing scheme creates higher risk to ETSA Utilities than a profit sharing scheme, as it has no regard to profitability. This is because a share of revenue might be

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42 Ibid.

43 Pole rental would currently be the major contributor to the profit in this category. Profits from pole rental are attributable to public street lighting (excluded distribution service) and mobile telephony (unregulated service).

allocated to discount prescribed distribution charges from a service that provides little (if any) profit. A sharing scheme based on revenue could potentially result in ETSA Utilities incurring a loss in the provision of that service.

The Commission therefore considers it appropriate to base the scheme on the amount of profit earned from providing the excluded or unregulated service. This scheme would have less risk given that ETSA Utilities would need to make a profit on the provision of the service in order for an amount to be allocated to offset prescribed distribution charges.

There are a number of ways in which a profit sharing mechanism could work, including a sharing mechanism based on:

- forecast profit for the 2005-2010 period, which is incorporated directly into the forward looking annual revenue requirements that are set for ETSA Utilities (as discussed in Chapter 11); and
- an annual price adjustment process that accounts for the previous year's actual profits (a P-factor).

The first option has the advantage of creating an incentive for ETSA Utilities to out-perform the benchmark that is set. This is because ETSA Utilities would retain any additional profit over that forecast by the Commission. However, it would be difficult for the Commission to accurately assess the types of other services that ETSA Utilities will provide and the associated profits that could be achieved over the 2005-2010 period.

The difficulties faced by the Commission in undertaking such forecasting would introduce unnecessary risk to ETSA Utilities. In addition, determining forecasts for unregulated activities could amount to heavy-handed pseudo regulation for these non-prescribed services, which again would not be considered desirable.

An annual price adjustment process does not require the Commission to undertake any such forecasting. ETSA Utilities would provide to the Commission the information required to administer this scheme on an annual basis. This scheme would still provide an equitable reflection of the use of regulated assets while not imposing additional risk on ETSA Utilities in providing non-prescribed services.

The extent to which ETSA Utilities' profits are shared has been based on:

- the level of incentive that would be sufficient for ETSA Utilities to continuously seek out profit opportunities from existing infrastructure; and
- ensuring the profit is material enough to share with ETSA Utilities' prescribed customers.

The Commission has decided that 40% of ETSA Utilities' pre-tax annual profits earned from those non-prescribed services that were provided using ETSA Utilities' regulated asset base will be included in the annual adjustment to ETSA Utilities' prices (the P-

factor). The Commission believes that this provides a measured introduction of the scheme without providing undue risk on ETSA Utilities' non-prescribed activities.[44]

A description of the actual P-factor that the Commission has introduced is set out in section 12.5.3. The P-factor is also included in the Formula Schedule in Part B of this draft price determination, reflecting an additional factor that describes how ETSA Utilities' average revenue control can change over the 2005-2010 regulatory period.

[44] This is the first time that such a profit sharing scheme has been introduced in Australia. The effectiveness of the P-factor scheme will be considered at the next price review.

3 SERVICE STANDARDS

The development of a Service Standard Framework (SSF) to apply to ETSA Utilities for the 2005-2010 regulatory period has been the subject of extensive consultation by the Commission.

In April 2003, the Commission released an Initial Thoughts paper on a possible SSF to apply in South Australia from the start of the next regulatory period on 1 July 2005. Following consultation on that paper and extensive discussions with ETSA Utilities, the Commission released a paper in June 2004 outlining its Working Conclusions on an SSF.

The development of the 2005 SSF has been guided by the outcomes of a consumer survey conducted in 2002 on behalf of the Commission, which provided information on those aspects of service most valued by consumers and their willingness to pay for these services.[45] Among its key findings, the survey revealed that around 85% of consumers were satisfied with their existing level of service and were generally unwilling to pay for improvements in these levels. The findings did not support the funding of initiatives to achieve improvements in average service levels across the entire consumer base but rather indicated a willingness to pay for improvements in service to poorly served consumers.

The Commission has therefore sought to develop a framework that focuses on providing an incentive to improve the reliability performance experienced by the approximately 15% or so of worst served consumers while maintaining average reliability levels for all consumers on a regional basis at historical levels.

The components that make up the proposed framework are similar to those that exist under the current Electricity Distribution Code. The three components comprise:

- Average network reliability standards to be applied to different regions of the network. ETSA Utilities would be required under the Electricity Distribution Code to use 'best endeavours' to meet these average standards. Average standards were also envisaged to cover aspects of quality of supply and customer service performance.
- A Service Incentive (SI) scheme, which provides ETSA Utilities with a financial incentive to improve certain aspects of service over time.
- A Guaranteed Service Level (GSL) scheme, which requires ETSA Utilities to compensate customers who have received service that is worse than a pre-determined guaranteed level.

[45] Refer 2002 report "Consumer Preferences for Electricity Service Standards" available at www.escosa.sa.gov.au/resources/documents/030409-R-Final_CSReport.pdf.

3.1 Average Service Standards

The Commission intends to maintain a set of average service standards in order to ensure that ETSA Utilities does not focus solely on improving service to the worst served customers at the expense of all other customers.

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These average standards underpin the distribution prices that ETSA Utilities charges all of its customers.

The Commission proposes to maintain "best endeavours" standards in respect of average standards for reliability of supply, quality of supply and customer service. The term "best endeavours" is not currently defined in the Electricity Distribution Code. However, a standard definition has been adopted and included in the Electricity Transmission Code and in the Energy Retail Code, the Energy Marketing Code and the Energy Customer Transfer and Consent Code.

In these codes, "best endeavours" is defined as:

> *"to act in good faith and use all reasonable efforts, skill and resources."*

The Commission proposes that this definition be incorporated in a revised Electricity Distribution Code, effective from 1 July 2005.

3.1.1 Supply reliability measures

The Commission proposes to adopt the following measures as the supply reliability average standards for the 2005 to 2010 regulatory period:

- average duration of supply interruptions per customer per year (SAIDI);
- average number of supply interruptions per customer per year (SAIFI);
- the time taken to restore supply to consumers following an outage (expressed as a percentage of customers who have supply restored within a defined time period).

At a broad level, these measures mirror the current average service standards in the Electricity Distribution Code. However, the proposed standards diverge from the existing arrangements with respect to the geographic regions to which the standards apply.

The Initial Thoughts paper proposed that the average standards be based on ETSA Utilities' 13 development regions in South Australia, which comprise: Adelaide CBD; Adelaide metropolitan area (comprising Northern, Eastern, Southern and Western suburbs); Eyre Peninsula and Upper North; Barossa; Eastern Hills; Mid North and Yorke Peninsula; Murraylands; South East; Fleurieu Peninsula; and the Riverland. This is in contrast to the urban / rural / remote regional distinction in the current SSF. The rationale for this change was to provide more transparency in monitoring reliability performance across regions.

However, in its Working Conclusions report, the Commission recognised ETSA Utilities' concerns with the potential volatility of reported reliability performance when measured across the 13 development regions.

This volatility could, for example, be driven by the occurrence of localised storms which might have a significant impact on individual development regions but whose impact would be moderated if there were some aggregation of regions.

ESCOSA therefore undertook, in conjunction with ETSA Utilities, an analysis of 3 years of historical reliability performance data (2000/01 to 2002/03) in order to assess the degree of volatility within and across the 13 development regions and to form a view on the degree to which it would be reasonable to combine some regions in order to reduce this volatility.

The outcome of this analysis was to identify 7 regions which are considered to provide a reasonable representation of differences in reliability performance across the State while eliminating more extreme variations arguably attributable to random, severe weather events.

The 7 regions are:

- Adelaide (central) Business Area;
- Major Metropolitan Areas (which includes the Adelaide metropolitan area, Mt Barker, Mt Gambier, Pt Augusta, Pt Lincoln and Whyalla);
- Barossa/Mid-North and Yorke Peninsula/Riverland/Murraylands;
- Eastern Hills/Fleurieu Peninsula;
- Upper North & Eyre Peninsula;
- South East; and
- Kangaroo Island

It should be noted that the Major Metropolitan Areas include the Adelaide metropolitan area and a number of regional centres in SA.

These regional centres have been included in the Major Metropolitan Areas on the basis that they are considered urban in nature and should be expected to receive reliability performance similar to that received by customers in the Adelaide metropolitan area. Their inclusion is supported by the Australian Classification of Local Governments, which defines these regions as "Urban, Regional towns/cities" on the basis of their population densities.[46] This approach does not differ significantly from the way in which the urban region is defined in the existing Electricity Distribution Code. Mt Barker is the only one of these regional centres that is not included in the current definition of "urban".

[46] Refer table F.3 of the National Office of Local Government publication '2001/02 Report on the Operation of the Local Government (Financial Assistance) Act 1995'.

The reliability of the distribution network for consumers on Kangaroo Island has been the subject of a separate detailed review. As a result of this review, a SAIDI reliability standard significantly better than the average historical performance experienced by Kangaroo Island consumers has been established. This is based on the premise that such a standard will act as a catalyst for the development of an appropriate solution to address the poor reliability performance on Kangaroo Island, as well as ensuring that the power supply to Kangaroo Island is not subject to a long term outage due to a fault on the undersea cable supplying the Island.

The historical average performance data for the seven regions, based on an average over 2000/01 to 2003/04, is set out in Table 3.1.

Table 3.1: Average of SAIDI and SAIFI over 2000/01 to 2003/04 (HV only)

	SAIDI (MINUTES)	SAIFI (INTERRUPTIONS)
Adelaide Business Area	24	0.29
Barossa/Mid-Nth & Yorke Pen./Riverland/Murrayland	237	2.00
Eastern Hills/Fleurieu Peninsula	340	3.16
Major Metropolitan Areas	109	1.36
South East	324	2.57
Upper North & Eyre Peninsula	362	2.38
Kangaroo Island	1,185	8.82
Statewide	**159**	**1.65**

At present, ETSA Utilities' reported reliability performance, and associated service standards, reflect outages on the high voltage distribution system only. The reliability standards in the Electricity Distribution Code, however, do not distinguish between high voltage (HV) and low voltage (LV) outages, and should reflect outages in all sections of the network.

From 1 July 2005, it is intended that all distribution outages (i.e. both HV and LV), be captured for reliability performance reporting purposes with service standards similarly set to reflect all distribution outages. The Outage Management System (OMS), due to be implemented by mid-2005, will incorporate a capability to record both low and high voltage outages. However, the OMS will not begin to accumulate data on low voltage outages until after 1 July 2005.

In its Working Conclusions report, the Commission set out the results of a study undertaken in 2002 by Sinclair Knight Mertz (SKM) into the impact of including low voltage outages in two key performance indicators for network reliability; viz SAIDI and SAIFI. The review established that the inclusion of low voltage outages in ETSA Utilities' network reliability performance figures for 2001/02:

- increased SAIDI from 143 minutes (HV only) to 148 minutes; i.e. by about 3%;
- increased SAIFI from 1.59 (HV only) to 1.63; i.e. by about 2%.

ETSA Utilities put forward the view that the above analysis underestimated the LV component of outages since, in part, it was based on an unusually cool summer when LV outages were significantly lower than in a normal year. In addition, as the major metropolitan region has the largest proportion of LV mains, it believed that the LV allowance in this region should be higher, say, 6.5% with the allowance for other regions set at 3%.

The Commission noted ETSA Utilities' views but did not believe that there was sufficient firm data to support LV adjustments of the type proposed by ETSA Utilities at this stage. It therefore proposed to apply a standard LV adjustment factor of 3% to HV-only reliability data, broadly in line with the findings of the SKM review. This methodology will be reviewed over time as more accurate information becomes available from the OMS.

The Commission has proposed the following SAIDI and SAIFI standards to apply in the 2005-2010 regulatory period:

Table 3.2: Proposed SAIDI and SAIFI Average Standards

	SAIDI (MINUTES)	SAIFI (INTERRUPTIONS)
Adelaide Business Area	25	0.30
Barossa/Mid-Nth & Yorke Pen./Riverland/Murrayland	240	2.10
Eastern Hills/Fleurieu Peninsula	350	3.30
Major Metropolitan Areas	110	1.40
South East	330	2.70
Upper North & Eyre Peninsula	370	2.50
Kangaroo Island	450	N/A
Statewide	**160**	**1.70**

Direct comparisons between the above proposed standards and the existing reliability standards in the Electricity Distribution Code are difficult primarily because of the changes to the regional definitions discussed earlier in this paper. The proposed standards are, however, reflective of average historical performance as set out in the above table.

It should be noted that the Commission has not previously, nor does it intend for the purposes of the new SSF, to set "state-wide" reliability targets. The inclusion of state-wide figures in the above table is for information only.

The regional variation in the proposed standards reflects differences in average historical reliability performance across these regions over the 4 year period 2000/01 to 2003/04. Broadly, the variations are consistent with the geographical and population characteristics of the different regions and the resultant nature of the distribution networks supplying them. For example, the reliability standards proposed for the more remote, sparsely populated regions as well as those subject to more severe weather conditions (Upper North & Eyre Peninsula, South East and

Eastern Hills/Fleurieu Peninsula) reflect the poorer historical reliability performance experienced in these regions compared with other more densely populated rural areas as well as metropolitan areas.

3

It should also be noted that there is no provision for the exclusion of the impact of severe weather events from the above measures. For more discussion of the topic of "excluded events", refer to section 3.2 later in this Chapter.

3.1.2 Time to Restore Supply Service Standard

The Commission intends to retain the service standard relating to the percentage of customers restored within a specified timeframe after a disconnection event. The standards currently imposed under the Electricity Distribution Code for this measure, along with ETSA Utilities' performance over the period 2000/01 to 2003/04, are set out in Table 3.3.

Table 3.3: Current Electricity Distribution Code standards for Time to restore supply and historical performance by ETSA Utilities

MEASURE	CURRENT STANDARD	PERFORMANCE 00/01	PERFORMANCE 01/02	PERFORMANCE 02/03	PERFORMANCE 03/04
Supply Restoration Times - Urban	80% within 2 hours	80%	86%	84%	83%
	90% within 3 hours	92%	95%	96%	94%
Supply Restoration Times - Rural	80% within 3 hours	81%	86%	78%	85%
	90% within 5 hours	94%	96%	93%	96%
Supply Restoration Times - Remote	80% within 5 hours	79%	79%	71%	75%
	90% within 7 hours	88%	90%	81%	85%

The current Performance Incentive scheme under the Electricity Distribution Code also contains a Time to Restore Supply measure with targets set for the Adelaide Central and Metropolitan areas (instead of an Urban target). The respective baseline targets are shown in Table 3.4.

Table 3.4: Current PI scheme targets for "Time to Restore Supply" measure

REGION	BASELINE TARGET
Adelaide Central	80% within 2 hours
Metropolitan area	80% within 2 hours
Rural	80% within 3 hours
Remote	80% within 5 hours

For the purpose of deriving its working conclusion in relation to restoration times, the Commission obtained information from ETSA Utilities on its performance in restoring supply within each of the proposed new regions, over the previous 4 financial years (2000/01 to 2003/04).

On the basis of this information and consistent with the principle of setting average standards in order to maintain current performance, the Commission proposed as its working conclusion that the standards detailed in Table 3.5 be adopted:

Table 3.5: Proposed "Time to Restore Supply" Average Standards

SUPPLY RESTORATION TIMES FOR:	PROPOSED STANDARD
Adelaide Business Area	90% within 2 hours 95% within 3 hours
Major Metropolitan Areas	80% within 2 hours 90% within 3 hours
Barossa/Mid North & Yorke Peninsula/ Riverland/Murrayland	80% within 3 hours 90% within 5 hours
Eastern Hills/Fleurieu Peninsula	80% within 3 hours 90% within 4 hours
Upper North/Eyre Peninsula	80% within 4 hours 90% within 6 hours
South East	80% within 4 hours 90% within 5 hours
Kangaroo Island	N/A

These standards reflect unplanned outages only, and do not incorporate planned outages. The Commission intends to maintain a separate requirement under the Electricity Distribution Code for ETSA Utilities to use best endeavours to minimise planned outages.

The restoration time standards also exclude interruptions on the low voltage network.

3.1.3 Quality of supply

The Commission proposes that average quality of supply standards, of a "best endeavours" nature, be retained in the service standards framework for the 2005–2010 regulatory period. Furthermore, it believes there is merit in retaining the quality of supply measures currently set out in clause 1.2.3 of the Electricity Distribution Code: viz quality of supply to be maintained at least in line with the relevant Australian Standards.

This position recognises the practical difficulty of ensuring compliance with supply quality standards at the individual consumer level and therefore accepts that a best endeavours test is reasonable.

The Commission will continue to monitor power quality as described in Electricity Industry Guideline No 1 in order to satisfy itself that ETSA Utilities is using its best endeavours to meet the relevant voltage and interference standards as set out in the Electricity Distribution Code.

The proposed quality of supply standards are set out in Table 3.6.

Table 3.6: Proposed Quality of Supply Average Standards

CATEGORY	DESCRIPTION OF MEASURE	STANDARD
Quality of supply	Voltage	As set out in AS60038
	Voltage fluctuations	Within limits as set out in AS/NZS 61000 Parts 3.3 and 3.5 and AS2279 Part 4
	Harmonic voltage distortions	Do not exceed values in AS/NZS 61000 Part 3.2 and AS2279 Part 2 and as set out in the schedule to the standard connection and supply contract
	Voltage unbalance factor in 3 phase supplies	Do not exceed values in the schedule to the standard connection and supply contract
	Interference	Less than limits set out in AS/NZS 61000 Part 3.5 and AS/NZS 2344

3.1.4 Customer service

The Commission proposes to retain average standards in relation to call centre performance and response times to written enquiries, with the measures to be of a "best endeavours" nature.

Call centre performance will be derived on the following basis:

- A call is considered answered when a customer selects one of the automated response services offered by the Integrated Voice Response (IVR) system.
- When a caller selects an IVR option which involves a request to speak to an operator, the call is considered answered only when the operator responds to the call.
- Calls abandoned within 30 seconds are to be added to the calls answered within 30 seconds for the purpose of measuring overall performance. In the absence of data on time periods before calls are abandoned, the percentage of calls abandoned within 30 seconds is to be assumed to be the same as operator requested calls answered within 30 seconds, with the assessment to be carried out on a daily basis.
- There is to be no provision for exclusions due to a major outage event in the measurement of telephone performance.

Based on the analysis of historical call centre performance data, it is proposed to retain the existing average call centre performance standard of 85% of calls to be answered within 30 seconds. This standard is consistent with the average historical performance over the previous 4 years.

No change is proposed to the average standards for responding to written enquiries. The proposed standards are set out in Table 3.7.

Table 3.7: Proposed Customer Service Average Standards

CATEGORY	DESCRIPTION OF MEASURE	STANDARD
Consumer service	Time to respond to telephone calls	85% within 30 seconds (including calls after a major outage event)
	Time to respond to written enquiries	95% within 5 business days
	Time to provide written explanation for interruptions to supply	85% within 20 business days

3.2 Service Incentive Scheme

The 2002 survey of consumer preferences for improvements in electricity distribution services suggested that a significant proportion of consumers, around 85%, were satisfied with their existing level of supply reliability. Conversely, around 15% of consumers were dissatisfied with their reliability of supply.

The Commission has therefore formed the view that it is appropriate to provide an incentive for ETSA Utilities to improve service to those 15% of worst served consumers.

It also proposes that the measures to be adopted in the SI scheme be developed from the results of the consumer survey.

The Commission has considered the relative merits of various approaches to developing detailed reliability performance measures for the SI scheme. It has also considered a range of other measures that could potentially form part of an SI scheme and has considered arguments as to why it is, or is not, appropriate to include them in the scheme.

A summary of the Commission's proposals in relation to the SI scheme is set out below.

3.2.1 Reliability of supply

In its Initial Thoughts paper, the Commission proposed that the following reliability performance measures be included in the SI scheme:

- percentage of consumers who experienced more than x interruptions in the last regulatory year;
- percentage of consumers who experienced more than y minutes of interruptions in the last regulatory year; and
- percentage of consumers who experienced an interruption longer than z minutes in the last regulatory year.

In responding to the Commission's proposed measures, ETSA Utilities has suggested that, instead of aiming to reduce the percentage of customers that experience performance worse than a threshold level ('above threshold'), the SI scheme should encourage it to improve the average service levels to all those customers above the threshold. This would remove what it considered to be an unintended consequence of the proposed scheme, which was that it focused only on those customers who experienced reliability performance around the threshold

level. ETSA Utilities argued that the Commission's proposal did not provide any incentive for them to improve the level of service to customers experiencing performance far worse than the threshold level, since a reward would only be given if service improved to a level below the threshold, not if it improved but still remained above the threshold. It suggested that a target based on improving the average service levels to all consumers above the threshold was more consistent with the results of the customer survey, since customers above the SI threshold would value improvements in performance even if it did not move them to below the threshold.

The Commission recognised the merit in ETSA Utilities' comments regarding the potentially unintended consequences of the incentive proposed in the Initial Thoughts paper. Alternative reliability measures were therefore considered that would provide ETSA Utilities with an incentive to target a wider range of customers above the threshold.

As indicated above, ETSA Utilities had suggested measures based on the average performance, in terms of SAIDI and SAIFI, for all customers above the threshold. This would overcome the problem of only being encouraged to target customers near the threshold level. However, it is possible that an improvement in the SAIDI or SAIFI for these customers in one year may lead to a higher SAIDI or SAIFI target in the following year since the customers remaining above the threshold could have, on average, a worse reliability performance than the above-threshold group for the previous year.

Following further discussions with ETSA Utilities, an alternative approach was developed to take account of the possible impact on the targets from year to year. The proposed approach was to measure the customer minutes off supply for those customers that have experienced reliability service levels that are worse than a specified threshold. This measure would be calculated as the number of customers affected by an interruption (assumed to all be customers on a feeder that has above threshold performance) multiplied by the average number of minutes off supply per customer (the feeder SAIDI).

In its Working Conclusions, the Commission favoured the customer minutes measure over the alternative measures, because it delivered an incentive to improve performance to all customers above the threshold while avoiding the possible consequence of an improvement in performance leading to a more difficult target in following years (since it is not expressed as an average).

Other aspects of Working Conclusions on reliability of supply

(a) Number of regions

The proposed SI scheme will be based on one region only (statewide), rather than having separate targets for different regions.

(b) Calculation of the threshold level of service

The threshold level of service is the point at which customers are generally willing to pay for an improvement to the level of service they experience. The SI scheme is intended to focus only on those customers above this threshold.

This threshold was determined from the results of the 2002 customer willingness to pay (WTP) survey, which found that customers who perceived that they had received 3 or more interruptions in the previous year were generally willing to pay for a reduction in the number of interruptions experienced[47], and customers who perceived that they had received at least 180 minutes of interruptions in the previous year (after calibration to allow for the difference between actual and perceived service levels) were willing to pay for an improvement in the total duration off supply.

(c) Criteria for determining the "worst served" customers

The baseline targets will be calculated by examining the feeders that have experienced two consecutive years of three or more interruptions or 180 or more minutes off supply per annum. This test will ensure that the scheme focuses on feeders that have exhibited poor performance that is more systemic, rather than if they were based on 1 year's performance.

On the basis of historical performance, approximately 18% of customers meet this latter criterion, which produces a result that is consistent with the intent of focussing the scheme on the worst served 15% of customers.

(d) Measurement of performance

Performance against the baseline targets will be assessed over a two-year period. A two-year period for measuring performance is considered preferable to a one-year period because it will reduce the impact of one-off events, such as storms.

The first assessment of performance under the SI scheme will occur at the end of the 2005 calendar year. This assessment will look back at average annual customer minutes of above threshold feeders over the 2004 and 2005 years and compare this performance to the baseline target, which will be calculated as average annual customer minutes of above threshold feeders over the 2001 to 2004 period. Performance will be assessed for each subsequent calendar year (year t), comparing the performance of above threshold feeders over years t-1 and t-2 to the performance of above threshold feeders calculated over years t-2 and t-3.

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[47] This number has been rounded from the actual number derived through the consumer survey, which was 2.53 perceived interruptions per annum which, after calibration, equates to 2.45 interruptions per annum as measured at the HV feeder level by ETSA Utilities.

Under this proposed scheme, the feeders that are determined to be worse than the threshold in setting the baseline target need not be the same feeders as those for which performance is assessed.

Any revenue adjustments arising from the first assessment will take effect from 1 July 2006. Performance assessments will take place after each calendar year based on the previous two years of data, until the last year of performance assessment under the SI scheme at the end of 2010.

The Commission will be developing an initial baseline target, which will be dependent on ETSA Utilities' historical reliability performance, including performance during the 2004 calendar year. This target will be known by the start of 2005.

(e) Calculation of bandwidths

It is proposed that the measurement of performance under the SI scheme allow for dead bands, similar to the current PI scheme. These dead bands will reduce the impact of natural variation in performance, thereby limiting the financial risk to ETSA Utilities resulting from events outside its control.

There will be three bands either side of the baseline target with improvements being rewarded to the same extent as deterioration in supply is penalised. The Commission proposes bandwidths of ±3% of the baseline target. These bandwidths are considered by the Commission to provide a reasonable balance between reducing some of the risk created by natural variability in customer minutes from year to year, while still providing an adequate incentive for ETSA Utilities to target reliability improvements.

(f) Exclusions

The Commission's proposal is to include all sustained interruptions, except those caused by transmission and generation failures, and those caused by disconnections during emergency situations. Other causes of interruptions, including those caused by weather or other factors outside ETSA Utilities' direct control (eg. third party events), will be captured in the performance data.

(g) Discrete vs Continuous Scheme

The Commission has proposed a continuous SI scheme, where baseline targets would be adjusted each year to reflect performance in the previous year. That is, the new baseline will be set at the threshold bandwidth achieved in the previous year. If no incremental change in performance occurs, the baseline remains unchanged. The intent behind a continuous scheme is to only reward incremental improvement (and only penalise sustained worsening in performance).

The Commission believes that a continuous scheme will provide more appropriate incentives to ETSA Utilities than a discrete scheme. In particular, it considers that the continuous scheme has the following advantages:

- Given that the Efficiency Carryover Mechanism (ECM) will allow any expenditure efficiencies to be carried over by ETSA Utilities for a 5 year period, the SI scheme should also allow for any rewards to be carried over for 5 years. If the baseline targets were not adjusted each year, a reliability improvement in year 1 due to increased expenditure in year 1 would lead to greater rewards under the SI scheme than penalties under the ECM.
- A continuous scheme mitigates the impact of random events, since it only rewards sustained improvement and penalises sustained worsening of service.
- The Commission believes that a continuous scheme still delivers strong incentives throughout the entire regulatory period. ETSA Utilities will know that it will have to achieve ongoing improvement from the baseline targets set at the beginning of the regulatory period in order to earn a reward.

As noted earlier, the Commission intends to set initial targets and bandwidths for the reliability performance component of the SI scheme at the start of 2005 after details of ETSA Utilities' performance for 2004 become available.

3.2.2 Quality of supply

The Commission proposes not to include quality of supply as a performance measure under the SI scheme.

The Commission intends to retain minimum standards for quality of supply under the Electricity Distribution Code, but not to provide a financial incentive for ETSA Utilities to better those standards through the SI scheme. This is based on consumer survey results suggesting a low willingness to pay for incremental changes in supply quality and on a lack of accurate data measuring quality of supply.

3.2.3 Customer service

Call centre performance

The Commission proposes to introduce a performance measure based on the percentage of telephone calls responded to within 30 seconds. This measure has existed as an average standard during the current regulatory period and is proposed to continue as an average standard in the 2005-2010 regulatory period. The Commission proposes that this standard be included in the SI scheme, to reflect the value that consumers place on this aspect of service and because of the availability of historical information on this measure.

The baseline target for this measure is proposed to be the same as the proposed average standard (85%). This baseline level is consistent with the average level of service reported by ETSA Utilities over the previous four financial years (2000/01 to 2003/04). Under the proposed continuous scheme, performance would be assessed after each calendar year, with the baseline target being adjusted after each year to reflect performance in the previous year.

Based on historical information, which shows that there has been little variation in performance against this standard over the past 3 financial years, bandwidths of ±1 percentage point are proposed.

The proposed SI targets for "Percentage of calls answered in less than 30 seconds" are set out in Table 3.8.

Table 3.8: Proposed SI targets for "Percentage of calls answered in less than 30 seconds"

PERCENTAGE OF CALLS ANSWERED IN LESS THAN 30 SECONDS	POINTS
≤ 82%	-3
> 82% and ≤83%	-2
> 83% and ≤84%	-1
> 84% and <86%	0
≥ 86% and <87%	+1
≥ 87% and <88%	+2
≥ 88%	+3

Automatic detection of interruptions and accuracy of estimated restoration times

The Initial Thoughts paper discussed the willingness to pay indicated by some consumers in the consumer survey for the ability of ETSA Utilities to automatically detect when an interruption has occurred and to provide more accurate estimates of supply restoration times to consumers.

The paper suggested that significant systems would be required for ETSA Utilities to provide these aspects of service and that a separate review be conducted by the Commission rather than incorporate any relevant measures into the SSF.

Based on the above, the Commission's Working Conclusion was that it would not be practicable to incorporate the above aspects of service into the SI scheme.

The Commission will not incorporate the ability for ETSA Utilities to automatically detect when an interruption has occurred nor the accuracy of estimated supply restoration times into the SI scheme.

Method of notification of planned interruptions

The Initial Thoughts paper discussed whether the SI scheme should incorporate a measure based on the method by which ETSA Utilities notifies customers of a planned outage. The Commission proposed in its Working Conclusions that the method of notification not be included in the SI scheme due to inconsistent views from consumers as to the preferred method of notification.

The Commission will not incorporate the method of notification of planned interruptions into the Service Incentive scheme.

Undergrounding

The results of the consumer survey showed that consumers were willing to pay for increased undergrounding of overhead power lines. The Commission proposed in its Initial Thoughts paper that the issues relating to undergrounding be considered in a review conducted separately to the SSF development process.

The Commission released a discussion paper[48], in which it asked whether the amount of funding allocated to undergrounding should be increased and, if so, in what ways the undergrounding program might be expanded from 2005.

Following the consideration of submissions to this discussion paper, the Commission released a final report[49] concluding that increasing the level of funding to undergrounding projects was not appropriate given the pressure to reduce the price of electricity to consumers. However, the Commission also concluded that the possibility of an expansion to undergrounding funding should be considered prior to the commencement of future regulatory periods, when there may be less of a focus on the desire for lower prices. While an expansion of funding for undergrounding may not occur in the near future, the Commission is examining the potential for greater flexibility in funding arrangements, subject to Ministerial approval.

The above position was set out as the Commission's Working Conclusion and no change is proposed to this position.

The Commission is not proposing to expand the funding for undergrounding of electricity distribution infrastructure, but is considering the potential for greater flexibility in funding arrangements, subject to Ministerial approval.

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48 ESCOSA, '*Possible Approaches to Undergrounding Electricity from 2005: Discussion Paper*', November 2003.

49 ESCOSA, '*Approach to Electricity Undergrounding from 2005: Final Report*', January 2004.

3.2.4 Other measures

The Commission proposed that it retain the ability to introduce additional performance measures during the 2005-2010 regulatory period, as it would provide scope for ETSA Utilities to address unexpected issues in service levels that may arise.

ETSA Utilities agreed that other measures could be set in the future, as long as they satisfied the appropriate principles for inclusion, as discussed in the Initial Thoughts paper. It argued that the measures must be set on average historic performance and that any new measures should not lead to a dilution of the incentives for the existing measures.

In its Working Conclusions, the Commission agreed with ETSA Utilities' comments on the addition of any new measures. In developing an arrangement for retaining the ability to include new measures, the Commission will ensure that the points made by ETSA Utilities are taken into account.

The Commission will retain the ability for new performance measures to be introduced during the 2005-2010 regulatory period.

3.2.5 Determining the financial incentive

The Initial Thoughts paper proposed that the financial incentives attached to each performance measure be set at an amount that is reflective of consumers' WTP for improved services, rather than ETSA Utilities' costs. It proposed to increase the level of the incentives, which currently provide a maximum revenue gain or loss of less than ±1% of ETSA Utilities' aggregate regulated revenue. The increase, however, would be limited by results of the consumer survey regarding WTP.

In its Working Conclusions, the Commission confirmed its intention to increase the level of financial incentives from those currently set under the Performance Incentive scheme, limiting the increase to the levels indicated through consumer survey results. However, analysis of the total amount that consumers may be willing to pay for service improvements based on the consumer survey appeared to be considerably greater than the total financial incentive that the Commission would be prepared to put at risk under the scheme, given its desire to provide low and stable electricity prices to consumers.

The Commission proposed to limit the maximum annual financial incentive under the SI scheme to approximately ±2% of ETSA Utilities' current prescribed distribution revenue. In determining this maximum incentive, the Commission sought to strike a balance between providing a sufficient incentive for ETSA Utilities to target service improvements under the scheme, while limiting the financial risk and potential price volatility that may arise from setting the incentive too high.

The Commission proposed a maximum incentive of $2.1m per annum, which can be carried over for 5 years. Of this $2.1m annual maximum reward, approximately $0.3m was proposed to apply to the telephone response time measure. This was calculated based on the results of the consumer WTP survey. The remaining amount of around $1.8m was proposed to apply to the customer minutes measure. The Commission believed that this maximum incentive was below the maximum amount that consumers would be willing to pay.

The scheme would be structured so that there were three bandwidths either side of the baseline targets (unlike the current PI scheme which has a +3/-2 structure). Therefore, under the telephone response time measure, each point (which represents a change in performance of one percentage point) would be worth approximately $0.1m and under the customer minutes measure, each point (which represents a 3% change in customer minutes) would be worth $0.6m.

While the total financial incentive for reliability improvements under the proposed scheme was considered to fall within the amount that consumers are believed to be willing to pay, the Commission sought to confirm that the incentive was also above the marginal cost to ETSA Utilities of implementing such improvements. Modelling of the relationship between the cost of reliability improvement and the financial incentives available under the SI scheme was undertaken by the Commission. ETSA Utilities provided the Commission with estimates of the cost of delivering reliability improvements based on a previous study conducted in 2002 on behalf of the Office of the SAIIR (now ESCOSA) and ETSA Utilities.[50] Based on providing improvements to the current level of performance, the estimates provided by ETSA Utilities appeared to fall below the financial incentives proposed under the SI scheme. Therefore, the Commission believed that the scheme would deliver appropriate financial incentives to ETSA Utilities.

In addition to an annual maximum financial incentive, the Commission also considered whether there should be an overall limit on the maximum financial incentive for the reliability measure in the SI scheme, given that the measure is new and that the target would be based on limited data. If ETSA Utilities' performance against the reliability measure were to significantly improve or worsen over the 2005-2010 regulatory period to such an extent that the overall limit is breached, then any additional improvement or worsening in performance would not be rewarded or penalised. Therefore, the overall limit would reduce the financial risk to consumers and ETSA Utilities of any significant variation in performance against the initial baseline target over the 5 year period, while the annual maximum incentive reduces the risk of variation in performance from year to year.

The Commission intends to limit the total financial incentive for this measure to $30m (compared to the $45m that would be available based on $1.8m of

[50] Refer ESCOSA Information Paper No. 9: 'Future Power Quality and Reliability Requirements for South Australia', April 2002.

rewards/penalties for each year, carried over for five years). This limit will apply in respect to both incentive payments received by ETSA Utilities and incentive penalties incurred. The total financial incentive for the entire SI scheme would therefore be capped at $37.5m, which represents around 1.6% of ETSA Utilities' current prescribed distribution revenue.

3.3 Guaranteed Service Level Scheme

It is proposed that the Service Standard Framework include a Guaranteed Service Level (GSL) scheme, which will provide customers with direct payments from ETSA Utilities if their level of distribution service falls below a predetermined threshold. The GSL scheme would recognise that the level of service experienced by some distribution customers is unlikely to improve in the future due to the high cost of implementing service improvement projects for these customers. The Commission considers it appropriate for these customers to receive compensation for such service levels.

The Initial Thoughts paper had proposed that customers should be compensated by ETSA Utilities if:

- they receive greater than X interruptions in a regulatory year;
- they receive an interruption greater than Y minutes in duration in a regulatory year;
- their new supply address is not connected within Z days after meeting necessary preconditions.

The current GSL in relation to timeliness of appointments was proposed to be removed from the new SSF based on the minimal impact of this measure on customers.

The Commission proposed to continue the street light outage reporting scheme, which requires ETSA Utilities to make a payment to any customer who reports a street light fault which is not repaired within a specified time period.

Following stakeholder feedback, the Commission has developed the following proposed GSL scheme.

3.3.1 GSLs 1 and 2: Number of interruptions and longest interruption

Who is eligible for payment?

The Commission proposes to make the GSL payment available to all customers that experience reliability worse than the predetermined level, regardless of the type of customer (residential or business) and regardless of their location on the distribution network. The same threshold level of service would apply to all customers.

Thresholds and payment amounts

In establishing the GSL settings, the Commission has been guided by an analysis of ETSA Utilities' historic performance over the past 4 years.

The Commission has reviewed ETSA Utilities' reliability performance data (HV only) for the four financial years (2000/01 to 2003/04), and examined the proportion of customers that received service below various thresholds.

Based on this analysis, the Commission proposed that customers who experience more than 9 interruptions per annum or an interruption greater than 12 hours duration, would be entitled to a GSL payment. These thresholds are consistent with those established in other jurisdictions.

3.3.2 Determining the level of compensation

Also in line with the amounts determined in other jurisdictions, the Commission proposed that ETSA Utilities make a payment of $80 when a customer experiences more than 9 interruptions per annum or 12 hours off supply for any single interruption.

The Commission also proposed that the amount of compensation received by a customer should vary depending on the actual level of reliability experienced. In other words, once the customer's reliability service has met the initial threshold, the level of payments would increase as reliability worsens.

While the Commission still supports such a principle, it is also conscious that the administration costs of the scheme should be kept to a minimum. It therefore proposes that there should be three increments of service for which different payments would apply. The amount of payments would be capped at the third increment.

The proposed increments would be set such that additional compensation should be paid if reliability worsens beyond the initial threshold by blocks of 3 hours or 3 interruptions. For each increment, the customer would be entitled to an additional $40 payment (on top of the initial $80). Hence, the total amount that any customer could receive in respect of the duration of interruption GSL would be $160 per event and the maximum amount that could be received by a customer for the frequency of interruptions GSL is $160 per annum.

Table 3.9 and Table 3.10 summarise the thresholds (based on average performance over 2000/01 to 2002/03).

Table 3.9: Thresholds and payment amounts – duration

	THRESHOLD 1	THRESHOLD 2	THRESHOLD 3
Duration (hrs)	>12 and ≤15	>15 and ≤18	>18
Payment	$80	$120	$160

Table 3.10: Thresholds and payment amounts – frequency of interruptions

	THRESHOLD 1	THRESHOLD 2	THRESHOLD 3
No. of interruptions pa	>9 and ≤12	>12 and ≤15	>15
Payment	$80	$120	$160

The total amount of payments that ETSA Utilities is expected to make each year for these two GSLs, based on current customer numbers, is estimated to be approximately $1.2m (which is around 0.2% of annual DUOS revenue). This amount has been incorporated into ETSA Utilities' regulated revenue base for prescribed services. If ETSA Utilities is able to improve service to the worst served customers and keep GSL payments below this amount, then it will be able to retain the benefit of avoided payments. On the other hand, it will be penalised by having to make more than expected GSL payments if performance is below that forecast.

Any payment by ETSA Utilities for failure to meet a GSL must be done proactively. To minimise administration costs, payments for the frequency of interruptions GSL may be made in the quarter directly following the regulatory year (ending 30 June). Payments for the duration of interruptions GSL should be made within a quarter of the event occurring. Payments will be made in respect of the supply address. ETSA Utilities will not be required to track the reliability performance of individual persons who may move address from time to time: the measure will apply to a supply address, not a consumer.

3.3.3 Single Customer Faults

The Commission proposes that the GSL scheme exclude interruptions caused by the following:

- transmission and generation failures;
- disconnection required in an emergency situation (eg. bushfire); and
- single customer faults.

The Commission supports the exclusion of single customer faults from the GSL scheme on the basis that they are caused by a customer rather than the distributor and that they are easily identifiable and can be measured accurately. The Commission will be requesting information from ETSA Utilities on the extent of single customer faults during the 2005-2010 regulatory period in order to review the impact of this exclusion.

3.3.4 GSL 3: New connections

The Electricity Distribution Code currently requires ETSA Utilities to connect a new supply address within 6 business days after the customer meets the necessary pre-conditions (as set out in the Electricity Distribution Code), or pay the customer $50 for each day they are late, up to a maximum of $250.

The Commission is of the view that this GSL is still of value to customers and it therefore proposes to retain this GSL in its current form.

3.3.5 GSL 4: Timeliness of appointments

In its Initial Thoughts paper, the Commission proposed not to continue with the current requirement for ETSA Utilities to pay customers $20 if it is more than 15 minutes late for an appointment with the customer. This GSL is currently specified in clause 5.3 of Part B of the Electricity Distribution Code.

However, in its Working Conclusions, the Commission was of the view that there may be some merit in continuing with this GSL, particularly given the transfer of meter reading responsibilities from AGL SA to ETSA Utilities as part of the introduction of Full Retail Contestability (FRC).

The current GSL requiring ETSA Utilities to pay customers $20 if it is more than 15 minutes late for an appointment with the customer will continue during the 2005-2010 regulatory period (and will apply to meter reading activities).

3.3.6 Street light reporting scheme

As discussed in the Initial Thoughts paper, the obligation for ETSA Utilities to pay customers who report street light faults, which aren't repaired within a specified timeframe, does not strictly constitute a GSL. Rather, the street light reporting scheme was introduced as an alternative to ETSA Utilities conducting street light patrols.

The Commission has determined that, while it intends to retain this scheme, the details of the scheme will be considered as part of a separate review of the Electricity Distribution Code prior to the commencement of the 2005-2010 regulatory period.

3.4 Implementation of the Service Standard Framework

The components of the SSF discussed in this Chapter will be implemented through the Electricity Distribution Code, which will be revised by the Commission prior to the commencement of the 2005-2010 regulatory period.

4 DEMAND MANAGEMENT

ETSA Utilities' expenditure submission to the Commission incorporated an allowance for a range of pilot network demand management programs to be undertaken during the next regulatory period. ETSA Utilities' included proposed expenditure on these programs in its submission in anticipation that the Commission would approve funding for such programs.

Charles River Associates (Asia Pacific) Pty Ltd (CRA) was retained by the Commission to assess the net benefit-cost of using demand management initiatives, including appropriate pricing signals in combination with interval metering[51], to defer augmentation of constrained network elements on ETSA Utilities' distribution system.

CRA's scope of work for this assessment comprised the following broad phases:

- *Phase 1* – Provide an overview of the demand management strategies applicable to ETSA Utilities' distribution network, i.e. with potential to defer peak capacity driven supply-side augmentation.
- *Phase 2* – Undertake a detailed assessment of the relative cost-effectiveness of using demand management strategies (including use of interval meters) to delay supply-side upgrades on short-listed network areas assessed during Phase 1 as having high potential for such deferment. This phase should also define regulatory issues that could impede the implementation of demand-side activities by ETSA Utilities, and recommend mechanisms to overcome perceived barriers.

The Commission acknowledges that demand management initiatives can be of benefit to the electricity distribution business and others, such as retailers. It is important to stress that the Commission's decision on funding of demand management initiatives has been based primarily on the costs and benefits from the network perspective. Nevertheless, the Commission has also taken into consideration possible benefits to other sectors of the electricity supply industry.

Based on the CRA study and the Commission's own reviews over the last 12 months or so, the Commission has now reached conclusions about the types of demand management initiatives that should be funded in the next regulatory period, the amount of funding that should be provided, and the manner in which these initiatives should be implemented and monitored.

ETSA Utilities' expenditure submission highlights examples of potential strategies that may assist in reducing peak demand at times of network constraint. These include interrupting the load of major industrial users, thermal storage systems (e.g. associated with commercial air-conditioning systems), direct load control of air-conditioning systems, and the provision of pricing signals to provide an incentive for customers to reduce demand at times of peak demand. The last of these initiatives would also require the use of metering systems that can measure demand by time-of-day e.g. interval meters.

[51] Interval meters record the consumption of electricity on a half-hourly basis, whereas conventional meters record the total accumulated electricity use over the period between meter reads. Interval meters may thus provide the opportunity for retailers to provide more cost reflective price signals in tariffs.

The demand management research commissioned and undertaken by the Commission provides justification for the Commission supporting further work in some areas of demand management. Details of the areas identified by the Commission are set out below.

It should be noted that the Commission already imposes regulatory requirements on ETSA Utilities regarding network augmentation and extensions. Electricity Industry Guideline No 12, *Demand Management for Electricity Distribution Networks*[52], requires ETSA Utilities to investigate whether it would be cost effective to avoid or postpone network expansions by implementing measures to reduce demand on the network[53], before undertaking any significant expansion of the network.

Under Guideline 12, ETSA Utilities is required to publish an annual Electricity System Development Plan that identifies in detail any actual and forecast constraints on the distribution network This may assist proponents of demand management initiatives to assess the potential for such initiatives in constrained parts of the network. This information must be sufficient to allow customers and interested parties to assess whether and how they might be able to assist in addressing the constraint.

The first such Development Plan was published by ETSA Utilities in accordance with Guideline No. 12[54], at the end of June 2004. The Commission is monitoring the extent to which this initiative brings forward viable demand management proposals.

4.1 Demand Management Initiatives

The Commission believes that the programs evaluated in Phase 2 of the CRA study[55] provide a good indication of the range of programs that are suitable for reducing peak demands and should be considered for funding. Furthermore, the results of the CRA analysis have provided guidance to the Commission on funding priorities.

In the following sub-sections, the Commission outlines its views on the nature of demand management programs that it has decided to provide funding for ETSA Utilities to initiate over the 2005-2010 regulatory period. These are mostly pilot programs for specific initiatives, as well as activities designed to build ETSA Utilities' demand management capabilities and to aggregate the benefits of demand management across the industry.

Given the pilot nature of these programs, the Commission did not consider it appropriate to make adjustment to capital expenditure allowances, demand forecasts or lost revenue over the five year period.

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52 Available on the Commission's website (http://www.escosa.sa.gov.au/resources/documents/030901-O-Guideline12-DemandManagement.pdf)

53 Refer clause 14 of the distribution licence held by ETSA Utilities (http://www.escosa.sa.gov.au/resources/documents/021216-D-EUOn-gridLicence-FRC.pdf).

54 Available from the ETSA Utilities website, www.etsa.com.au.

55 CRA Report – Assessment of Demand Management and Metering Strategy Options - available from the Commission's website (http://www.escosa.sa.gov.au/resources/documents/040831-R-CRADemandManagement.pdf)

4.1.1 Power Factor Correction

In 2001, ETSA Utilities introduced a number of voluntary kVA (power factor dependent) tariffs. Under these tariffs, demand-metered customers are charged lower energy charges, but agree to have their peak demand metered on a kVA rather than kW basis. To date, customers who have accepted these tariffs are generally those with relatively good power factors[56]. While such customers have thereby received a more cost-reflective price, it could be concluded that the kVA tariff program of ETSA Utilities has not induced many customers to improve their power factors. In response, ETSA Utilities has revised the kVA tariff program to include a requirement that the customer makes a commitment to improving its power factor in order to qualify for the tariff.

The Commission believes that ETSA Utilities should place a strong emphasis on power factor correction. It notes that the Schedule to Part B of the Electricity Distribution Code ("The Standard Connection and Supply Contract") imposes obligations on all customers in relation to appropriate power factor ranges at times of maximum demand. The Commission understands that, in many instances, large customers are not meeting these contractual requirements.

The Commission believes that there is a case to mandate the use of kVA tariffs for all customers with annual electricity consumption greater than 750 MWh. The Commission considers that such an approach would be successful both in improving the overall capability of ETSA Utilities' distribution network and in deferring network augmentation in both the short and long term.

To encourage customers to take corrective action and improve their power factor, the Commission has decided to provide funding for ETSA Utilities to develop an assistance program, to be approved by the Commission, for customers who opt to go on a kVA tariff, by mid-2008, The assistance program is expected to include direct financial assistance from ETSA Utilities to the customer for the installation of the required power factor correction equipment and metering (if required).

The Commission believes that this approach will encourage large customers to adopt a kVA tariff early because of the technical and financial assistance available from ETSA Utilities. The initiative would also ensure that, ultimately, all large customers would receive more cost-reflective price signals for network services.

4.1.2 Standby Generation

The Commission believes that it is appropriate to initiate a standby generation pilot program. The first stage of this program would be an assessment of the technical and environmental barriers of connecting and operating existing embedded

[56] Power factor is essentially the ratio of the useful work performed by an electrical circuit compared to the maximum useful work that could have been performed at the supplied voltage and amperage. A low power factor is generally considered to be anything less than an 80% to 90% power factor rating.

generation equipment in parallel with the distribution network. The generators could then be used to provide network support (if required) and/or generating capacity during peak load periods. The Commission believes that, in the first instance, this assessment should be based on the 5 large customers, with standby generation equipment, identified by CRA in the North Adelaide area.

If the outcomes of these assessments are favourable, then ETSA Utilities will proceed with the implementation of the pilot program. It is envisaged that, subject to reaching suitable funding arrangements, 2 or 3 generators would be upgraded with the required protection and synchronising equipment to allow these units to operate in parallel with the distribution network.

It is also envisaged that ETSA Utilities could pay up to 100% of the "total conversion cost", subject to negotiations between the parties. It is expected that an incentive would be paid to the participants to compensate them for operating the generator when called upon by ETSA Utilities. This could include a portion of any financial benefits resulting from use of the generator.

The Commission would expect that the participating generators be modified and available for commercial use by the end of 2007, and that they operate as part of the pilot program for a minimum of 2 years, with the aim of identifying the merit of embedded generators providing network support and/or generation capacity during peak load periods. If this pilot program were successful, then the Commission would expect ETSA Utilities to consider other suitable embedded generation sites for conversion. The Commission also expects ETSA Utilities to work with developers constructing new buildings/facilities, during the planning stage, to examine the feasibility of installing embedded generator(s) for demand management purposes during the construction stage.

4.1.3 Direct Load Control (DLC)

On the basis of the results of the CRA study, and taking into account the outcomes of relevant studies in Australia and overseas, the Commission has approved funding for ETSA Utilities to pilot a DLC program involving 1000 to 2000 residential customers with suitable air-conditioning units, pool pumps or other suitable equipment.

The need for such a pilot program is underscored by the major contribution to peak electricity demand made by residential air-conditioners. Important issues to be addressed in this pilot will include an assessment of:

- the cost-effectiveness of different DLC control technologies;
- customer receptivity and take-up at various types and levels of incentive;
- load reduction impacts (as compared to projections);
- impact of cycling on air-conditioning operation;
- customer comfort;

- customer satisfaction; and
- the willingness of customers to stay on the program.

The Commission believes that it is appropriate to pilot suitable DLC initiatives under SA conditions for a minimum of 2 years. The Commission will work with ETSA Utilities in scoping the pilot study, the incentive scheme for customers and the target customer groups, and in monitoring the outcomes.

4.1.4 Critical Peak Pricing

Critical peak pricing (CPP) has been trialled in the US, and is suited to the demand management needs of networks. Under a CPP strategy, customers are notified in advance (usually a day or two ahead) of when a critical pricing period will be put in place. Peak prices on the critical day are significantly higher than on non-critical days – often 4 to 6 (or more) times as expensive. This approach reflects the fact that peak demand only occurs on a handful of occasions, and that additional capacity to meet this demand is very expensive. Tariffs during non-peak periods are reduced and customers participating in a CPP program generally save money on their total annual electricity bills.

Implementation of CPP requires interval metering, though remote reading capabilities are not necessarily required.

Given the significant costs involved in the installation of interval meters for all customers, the Commission has decided that a CPP trial be undertaken with customers that already have interval meters. The program will include technical and possibly financial assistance to end-use customers.

For the purposes of this program ETSA Utilities will be required to develop by December 2006, for approval by the Commission, CPP tariff(s) for large customers that currently have NEM compliant meters installed. Customer participation in this trial would be voluntary. It would also be necessary to develop an associated information and marketing strategy for all eligible customers.

The Commission recognises the difficulty in introducing a CPP trial for this group of customers, and therefore the Commission will work with ETSA Utilities to develop appropriate CPP tariff(s) and incentives for customers that currently have interval meters installed. The Commission expects that this will require close cooperation between ETSA Utilities and active SA retailers.

4.1.5 Interval Meters

Interval metering has been widely promoted as a tool to provide market-based signals to consumers in order to manage their electricity demand. Various reviews have concluded that interval metering is an essential tool for sending price signals to consumers to minimise their demand for electricity at times of high system peak demands and, by doing so, providing a demand side response to counter high system prices.

The major barrier to the introduction of interval metering is the cost of purchasing and installing the new meters, to which needs to be added the costs associated with the collection, processing and subsequent application of the data which the new meters will generate. The cost of rolling out interval meters to all residential and small business customers in SA has been estimated to be between $110m and $210m.

Interval meters have been used in SA since the introduction of the NEM. The use of interval meters has been limited to predominantly very large users of electricity. The Commission notes that there have been monetary benefits to such consumers moving to market contracts. These benefits have offset the additional metering costs involved. However, the Commission believes that the transition point between the cost of introducing interval metering and the benefits that accrue, occurs at an electricity usage level well above that of most residences and small businesses.

Based on the CRA study, the Commission does not accept that the introduction of interval metering combined with pricing signals will provide sufficient certainty of a resulting demand reduction to permit the deferral of network augmentation. Therefore, the Commission has determined that it is not appropriate to have a "wide scale" roll out of interval meters to all customers at the present time. The primary reasons for this conclusion are:

- the high cost associated with such a roll out, with resultant impact on prices; and
- lack of confidence regarding the impacts, either on network augmentation requirements, or on the provision by retailers of pricing signals that reflect peak demands.

4.1.6 Voluntary Load Control and Curtailable Load Control for large customers

Voluntary load control (VLC) and curtailable load control (CLC) are conceptually similar demand management initiatives. Both are voluntary programs designed to provide business customers with the opportunity to reduce electricity usage during peak periods in return for a financial incentive.

The CLC program is aimed at large businesses and involves the shedding of specific loads at times of peak demand in return for a financial incentive. The Commission estimates that about 50MW of curtailable loads are already in place in the SA electricity supply industry, through contracts between large customers and retailers.

The VLC program is aimed at medium businesses. Under the program each business is free to select the load reduction mechanisms (e.g. a thermal energy storage device) that minimises the impact on its operation, with an incentive payment being made to participating customers. A participant would be provided

with advance notification of a load reduction event, at which time it could elect whether or not to reduce its electricity use without penalty. Each participant's compliance would be measured by comparing interval meter data recorded during the load reduction event against a theoretical load curve.

The Commission believes that there are more opportunities to either shed loads or to shift such load to non-peak periods. Therefore the Commission supports funding ETSA Utilities to further investigate both CLC and VLC programs for application to business customers with interval meters already installed.

The Commission will work with ETSA Utilities to develop such initiatives. It notes that there is potential to involve retailers in the design and implementation of such programs.

The Commission notes that the scope for use of technologies designed to shift peak loads in certain business facilities is greatest during the construction phase of such facilities. For example, a thermal energy storage system can generally be installed more easily during construction of an office building than as a retrofit. Therefore ETSA Utilities will be encouraged to work with developers to assess such possibilities at the development stage of new projects. The Commission's new arrangement for charging for augmentation of the network will encourage and reward developers who reduce the peak-demand requirements of a project.

4.1.7 Aggregation

Recent national reviews of the NEM have commented that there is significantly less demand response in the electricity market than might have been expected, given the price signals available in the market. These reviews have identified certain barriers to demand management in the electricity market, which include the fact that net margins and the length of the typical retail electricity contract preclude retailers from making significant investment in either time or equipment to facilitate demand management initiatives. In addition, the disaggregation of what were once vertically integrated organisations into independent businesses makes it extremely difficult to realise all the benefits of demand management initiatives and hence to offset the costs involved.

As a result there is relatively little demand management available in the market for any application – network augmentation deferral, energy market arbitrage, or ancillary services.

The Commission is of the view that a means of re-aggregating the benefits of demand management should be investigated, especially if the market is to realise the demand management potential of smaller customers. The Commission believes that ETSA Utilities may be in a good position to act as a demand management aggregator. That is, it aggregates small and large loads/generating capacity so that it is in a position to bid this capacity into the national electricity market, like a large generator. Therefore, the Commission has decided to provide

funding to ETSA Utilities to assess the opportunities, costs, and benefits of becoming a demand management aggregator in South Australia.

4.1.8 Demand Management Organisation within ETSA Utilities

The CRA study made a number of recommendations regarding developing and improving the demand management capability within ETSA Utilities. The Commission agrees with CRA that it is important to improve ETSA Utilities' understanding and responsiveness to demand management initiatives. Therefore the Commission will approve funding to ETSA Utilities in the next regulatory period to:

- improve ETSA Utilities' understanding of demand management and use this knowledge in the network planning processes;
- integrate demand management strategies with traditional network supply-side planning;
- develop an information base about end-use loads; and
- re-analyse the 19 network areas that were identified in Phase 1 of the CRA study and any others identified by ETSA Utilities.

4.2 Funding

The previous section has set out the Commission's conclusions regarding a range of demand management programs that will be funded for ETSA Utilities to implement during the 2005-2010 regulatory period.

These programs are aimed at reducing peak electricity demand for the purpose of deferring network augmentation. However, wider benefits, for example a reduction in retail energy costs, may also result if means can be found to aggregate the benefits arising from separate components of the electricity supply industry.

The Commission notes that the question of funding requirements for each demand management initiative is complicated by the need to establish detailed arrangements for each program. ETSA Utilities is clearly in the best position to establish arrangements for final approval by the Commission. The Commission has requested ETSA Utilities to prepare detailed demand management proposals by 1 March 2005, based on a total funding allocation of $20 m spread over the next regulatory period.

Expenses incurred in implementing demand management initiatives during the next regulatory period will be treated as operating expenditure rather than capital expenditure, which means that the approved funding is not an amount to be incorporated into the regulated asset base.

Any over-expenditure will be at ETSA Utilities' cost. Any under-expenditure at the end of the regulatory period will be returned to customers during the 2010 – 2015 regulatory period.

4.3 Monitoring

The Commission will closely monitor the outcomes of each demand management initiative. The Commission envisages establishing specific reporting requirements for each of the pilot programs. Table 4.1 outlines expected outcomes to be monitored for the major pilot programs.

Table 4.1: Outcomes to be monitored for major demand management pilot programs

PILOT PROGRAM	OUTCOMES
Power factor correction	Improvements in power factors at customer installations; size of capacitors installed; cost of installing capacitors at each site; level of incentive payments; administrative costs.
Standby generation	Nature and cost of generator modifications; number of times that generators are used for network or system demand support; duration of support periods; kWh generated; peak load reduction outcomes; level of incentive payments; administrative costs.
Residential DLC	Details of the DLC system selected and reasons for that selection; details and costs of modifications to customer installations; cost components of the DLC system; number of customers involved; type and size of customer equipment controlled by the DLC system; times and duration that the system is used for network or system support; number of kW interrupted and the duration of interruptions; level of incentive payments; administrative costs.
Aggregation	The Commission will monitor ETSA Utilities performance in aggregating demand management resources within the NEM.

From the Commission's perspective, it is important that value is achieved from the programs that are funded. The programs suggested above have the potential to achieve positive returns for ETSA Utilities and the community. The Commission is committed to achieving progress in the area of demand management and will work with ETSA Utilities, consumer groups and the Government in the realisation of this potential.

The Commission is of the view that the pilot programs, and associated funding, as detailed in this chapter, provide a good foundation to trial various demand management initiatives under South Australian conditions.

These trials, and the experience gained, will be used by the Commission and ETSA Utilities to determine the benefits and costs for wider application.

It is the intention of the Commission to conduct a public review of the outcomes of this program of demand management initiatives in the final year of the 2005-2010 regulatory period, ahead of any consideration of ongoing funding. If some of the trials result in significant benefits to SA customers, the Commission will consider expanding such trials during the 2005-2010 regulatory period.

The Commission will closely monitor ETSA Utilities' expenditure on the approved projects on an annual basis.

5 SALES AND PEAK DEMAND FORECASTS

Peak demand, total electricity sales, and customer number forecasts are important inputs to the Commission's price determination process. Peak demand and customer number forecasts are relevant for determining the efficient level of capital expenditure required to meet future growth. Sales forecasts are primarily used to derive the average revenue controls for the 2005-2010 regulatory period.

To this end, in October 2003 the Commission asked the Electricity Supply Industry Planning Council (ESIPC) to prepare annual peak demand and energy sales forecasts for the South Australian distribution network for the 2005-2010 period.

ESIPC was established primarily to provide expert, independent advice to the South Australian Government and the Commission in relation to the state of the electricity supply industry in South Australia. It is a statutory corporation with wide-ranging responsibilities under the *Electricity Act 1996*[57] and, as such, does not have a financial interest in the quantum of the forecasts or the outcome of the Commission's price determination.

ESIPC presented its report "Review of demand forecasts for South Australia's electricity distribution network for the period 2005-06 to 2009-10" to the Commission on 12 March 2004[58], and its report "Sales forecasts by tariff category for South Australia's electricity distribution network for the period 2005-06 to 2009-10"[59] on 14 September 2004. The Sales report also included customer number forecasts. However, amendments have since been made to sales forecast numbers. This is an important point and is discussed further below in subsection 5.2.3.

5.1 Peak Demand

Anticipated growth of regional peak demands is a primary driver of the requirement for new network investment and therefore capital expenditure. ESIPC's peak demand forecasts have been used by the Commission in estimating the capital requirements for new investment in South Australia's electricity distribution network over the 2005-2010 regulatory period.

As discussed in chapter 7, forecasts of future demand are vital inputs to the building block model.

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57 The functions of the Electricity Supply Industry Planning Council are set out under section 6E of the Electricity Act 1996.

58 The report can be found on the Commission's website at http://www.escosa.sa.gov.au/resources/documents/040318-R-FinalReport-ESIPC.pdf .

59 The report can be found on the Commission's website at http://www.escosa.sa.gov.au/resources/documents/040916-R-ESIPCFinalSalesForecast-ESIPC.pdf.

5.1.1 Peak demand forecasts undertaken by ESIPC

ESIPC prepared diversified peak demand forecasts (MW) by region (discussed below) and year, split between ETSA Utilities' major customers[60] and all other customers in a particular region for each of the five years from 2005/06 to 2009/10.[61] Not all large customers are connected to the ETSA Utilities distribution network: some are connected directly to the transmission network and are excluded from these forecasts.

For planning purposes, ETSA Utilities divides the electricity distribution network into development regions, which represent groupings of the electrical layout of the distribution network. The Commission based its six regions[62] for which average standards apply on an aggregation of ETSA Utilities' development regions, and it is according to these six regions that ESIPC has prepared its peak demand forecasts.

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The fact that the forecasts are on a regional basis rather than at the State level, reflects differences across the State in existing network capacity, growth rates and the need for new investment to supply regional peak.

5.1.2 Overview of Methodology

ESIPC used the 10% probability of exceedance (PoE)[63] summer maximum demand forecasts for the base case economic growth assumptions published in its 2003 Annual Planning Report[64] as the starting point for its distribution network peak demand forecasts.

The state-wide forecasts were then split between ETSA Utilities' demand and ElectraNet SA's[65] other customers. Allowances were made for transmission network losses, generator loads and the effect of embedded generation connected to the transmission system. This resulted in estimates of ETSA Utilities' overall peak demand measured at transmission system exit points at the time of overall system peak demand.

ETSA Utilities' total demand at transmission exit point was then multiplied by the percentage forecast share of demand attributable to each region to arrive at an

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60 ETSA Utilities' major customers are considered to be those with peak demand of 5MW or more. There are some 25 customers in this category.

61 For the Commission's cost allocation purposes, ESIPC also prepared diversified peak demand forecasts by tariff category.

62 At the time ESIPC was requested to prepare these forecasts, the Commission proposed six regions for the purposes of setting average reliability standards. Subsequently, the Commission has proposed establishing a separate reliability standard for Kangaroo Island, bring the number of regions to seven. Further details on each of the regions are presented in Chapter 3.

63 The 10% PoE forecasts represent values that, in a statistical sense, should be exceeded only once in every ten years. They are not forecasts of the absolute maximum that might be reached under all conceivable circumstances.

64 The ESIPC's 2003 report can be found at www.esipc.sa.gov.au. The Annual Planning Report presents demand forecasts on the basis of three different probability of exceedance (PoE) levels (10%, 50% and 90%) and for three different economic growth scenarios (low, base case, and high).

65 ElectraNet SA is the transmission network operator in South Australia.

estimate of the coincident peak demand for each region. A diversity load factor for the region was then applied, representing the ratio of outright peak demand to demand at the time of the overall system peak.

Allowances were made for these proportions to continue to change over time in line with historic trends and for load diversity across regions, in order to arrive at diversified regional demand forecasts. Adjustments were then made for distribution network losses and the contribution of embedded generation connected to the distribution network so that regional demand at customers' meters could be estimated. The forecasts for each region were then split into demand by major customers and others using data provided by ETSA Utilities. The results are shown in Table 5.1.

Table 5.1: Regional distribution system demand forecasts by customer group (MW)

	MAJOR METROPOLITAN AREA	ADELAIDE CBD	BAROSSA /MID-NORTH/ RIVERLAND/ MURRAYLANDS	EASTERN HILLS/ FLEURIEU PENINSULA	SOUTH EAST	UPPER NORTH/ EYRE PENINSULA
Region total peak demand (customer meters)						
2005-06	1809.1	212.7	319.6	126.9	166.5	217.3
2006-07	1856.1	218.6	328.3	130.5	169.9	223.0
2007-08	1906.7	224.6	337.2	134.1	173.3	228.9
2008-09	1960.5	231.4	347.3	138.3	177.2	235.5
2009-10	2016.2	238.2	357.4	142.4	181.2	242.2
Major customers demand at time of regional peak (customer meters)						
2005-06	97.7	0.0	2.3	0.0	47.1	29.6
2006-07	99.2	0.0	2.3	0.0	47.1	29.6
2007-08	100.8	0.0	2.3	0.0	47.1	29.6
2008-09	102.5	0.0	2.3	0.0	47.1	29.6
2009-10	104.3	0.0	2.3	0.0	47.1	29.6
Other customers at time of regional peak (customer meters)						
2005-06	1711.4	212.7	317.3	126.9	119.4	187.7
2006-07	1756.8	218.6	326.1	130.5	122.8	193.4
2007-08	1805.9	224.6	334.9	134.1	126.2	199.2
2008-09	1858.0	231.4	345.0	138.3	130.2	205.9
2009-10	1911.9	238.2	355.1	142.4	134.1	212.5

The top panel in Table 5.1 shows region total peak demand at customers' meters. This is the maximum capacity the network must be capable of meeting at any given time. Each figure in this panel is the sum of the corresponding demand from major customers (middle panel) and other customers (bottom panel) at time of regional peak.

A figure for forecast peak demand growth of 3% per annum over the period 2005/06 to 2009/10 can be derived from Table 5.1.

5.2 Sales Forecasts

Sales forecasts (forecasts of the volume of energy sold by the distributor) are a crucial input into the price determination, under the "average revenue" form of regulation to apply to ETSA Utilities over the 2005-2010 regulatory period. Under the average revenue form of regulation proposed by the Commission, where average revenue is determined per unit of sales (expressed in $/MWh), the amount of revenue that the distributor can earn will be positively correlated with the amount of energy that it delivers to consumers.

The impact of deriving accurate sales forecast is significant given that these forecasts are used to derive average revenue controls and, hence, prices. A forecast that is systematically lower than actual sales will produce prices that are generally higher than they otherwise would have been. This exposes electricity customers to the risk of understated forecasts. Likewise, the distributor faces the risk of overstated forecasts producing prices that are generally lower than they otherwise would have been.

In recognition of this risk to both consumers and ETSA Utilities, the Commission has proposed a mechanism to reduce the risk of sales forecast error, as discussed in Chapter 11.

The Commission has requested ESIPC to prepare forecasts of electricity sales for each of the five years from 2005/06 to 2009/10 for each of the tariff categories[66] in the current EPO. The sales forecasts are based on the base case economic assumptions relating to, amongst other things, Australian GDP and State GSP growth, household formation rates, and interest rates.

5.2.1 Key Drivers of Sales

Residential electricity usage (which accounts for around 50% of total usage across the distribution network) is determined by household numbers connected to the grid and average consumption levels per connected household. Forecasts of domestic customer numbers are related to population growth and household formation rates, while average consumption per connected household is related to real disposable income, real energy prices, weather conditions, domestic appliance penetration rates and end-use efficiency measures.

5.2.2 Methodology

Sales forecasts were prepared for the various customer classes served by ETSA Utilities' distribution network using the National Institute of Economic and Industry Research (NIEIR)'s Australian economic and modelling system. The model comprises a number of integrated modules[67]. The outputs from these modules,

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66 These categories are as follows: Sub transmission, Zone substation, High voltage, Large low voltage, Medium low voltage, Low voltage demand, Low voltage business two rate, Low voltage business single rate, Low voltage residential single rate, Low voltage off-peak controlled load, Low voltage un-metered overnight, Low voltage un-metered 24 hour.

67 National and State macroeconomic and industry activity modules, an energy forecasting module, an energy technology module, an energy environmental impact module, and an energy production and pricing module.

together with historic sales data by customer class (one of the key inputs into the forecasts), once adjusted for weather and price effects, provided electricity consumption forecasts by industry sector and customer class. These forecasts were then assigned to the various tariff categories.

In preparing the forecasts, assumptions were made about the impact on sales of:

- embedded generation;
- greenhouse gas abatement policies;
- energy efficiency measures implemented by the Federal and State Governments; and
- the possibility of the future uptake by residential customers of solar hot water.

The sales forecasts reflect recent increases in AGL SA's standing contract prices, but do not assume price reductions resulting from consumers moving to market contracts.

As there is a degree of uncertainty surrounding the ultimate size of consumers' demand response to price rises and its timing, the ESIPC undertook sensitivity analyses according to scenarios where the incremental loss in sales due to price increases were higher and lower than the original estimates reported by NIEIR.

5.2.3 Revision of the sales forecasts presented by ESIPC in its September report

Sales forecasts in ESIPC's report were based on an estimate of 2003/04 sales. This in turn was based on incomplete information for the full year and implied estimated sales growth of 0.8% on the previous year. However, ETSA Utilities' 2003/04 regulatory accounts show that it had zero sales growth on the previous year's figure, suggesting that the starting point for ESIPC's forecasts may have been too high and that the forecasts may have understated the price elasticity of demand and consumer's response to recent real price increases.

This, coupled with the fact that NIEIR had recently revised down the economic outlook for South Australia, indicated to ESIPC that the forecasts warranted revision.

ESIPC has advised that the revised numbers (incorporating NIEIR's revisions) it has provided (which appear in Table 5.2 and are used for the purpose of this Draft Price Determination) are preliminary and that NIEIR will undertake a more thorough analysis in February 2005. The Commission will use the February 2005 sales forecast numbers in its Final Price Determination for the purpose of arriving at an average revenue figure for ETSA Utilities.

5.2.4 Sales Forecast Figures

Table 5.2 shows sales forecast figures by tariff category for the 2005-2010 regulatory period.

Table 5.2: Distribution system sales forecasts by tariff category (GWh)

	Residential	Controlled Load	Unmetered O/Night	Unmetered 24 Hour	LV Business Single Rate	LV Business Two Rate	Low Voltage Demand	Medium Low Voltage Demand	Large Low Voltage Demand	High Voltage Demand	Zone Substation	Sum Transmission	ETSA Total	Growth (%)
2005/06	3,203.2	804.9	96.1	9.9	769.0	1,584.1	1,198.2	59.9	615.5	905.8	805.1	655.8	10,707.5	1.4
2006/07	3,237.3	801.4	98.2	10.1	763.3	1,636.9	1,241.3	62.8	624.0	915.5	804.0	666.6	10,861.3	1.4
2007/08	3,279.6	799.7	100.2	10.3	753.5	1,687.9	1,282.6	65.4	635.9	936.3	813.1	686.7	11,051.3	1.7
2008/09	3,324.0	798.5	102.3	10.6	745.3	1,741.9	1,326.6	68.3	646.4	952.2	817.3	703.0	11,236.4	1.7
2009/10	3,375.8	798.8	104.3	10.8	738.5	1,801.7	1,375.3	71.5	659.0	971.8	824.6	722.3	11,454.4	1.9

The average annual sales growth forecast for the period 2005-2010 derived from Table 5.2 is 1.7%.

5.3 Customer numbers

As mentioned in the introduction to this chapter, forecasts of customer numbers are an important input to the Commission's price determination process as they are partial determinants of the need for future capital expenditure.

ESIPC forecast customer numbers are provided in Table 5.3. These customer number forecasts may be revised in February 2005 when NIEIR undertakes its revision of the sales forecasts.

Table 5.3: Customer numbers and annual growth by tariff category

	Residential	Controlled Load	LV Business Single Rate	LV Business Two Rate	Low Voltage Demand	Medium Low Voltage Demand	Large Low Voltage Demand	High Voltage Demand	Zone Substation	Sum Trans-mission
Customer numbers										
2005/06	686,372	308,935	73,962	29,567	992	104	222	209	45.0	9.0
2006/07	698,727	311,209	74,036	30,573	1,029	108	225	211	45.0	9.0
2007/08	712,701	314,212	74,110	31,581	1,065	113	228	214	45.0	9.0
2008/09	723,392	317,355	74,184	32,561	1,100	117	231	216	45.0	9.0
2009/10	734,242	321,175	74,259	33,668	1,139	123	234	218	45.0	9.0
Annual growth of customer numbers %										
2005/06	1.2	0.1	0.5	3.5	4.0	5.0	1.4	1.2	0.0	0.0
2006/07	1.8	0.7	0.1	3.4	3.7	4.5	1.3	1.1	0.0	0.0
2007/08	2.0	1.0	0.1	3.3	3.5	4.0	1.3	1.1	0.0	0.0
2008/09	1.5	1.0	0.1	3.1	3.3	4.0	1.2	1.0	0.0	0.0
2009/10	1.5	1.2	0.1	3.4	3.6	4.5	1.3	1.2	0.0	0.0

6 THE EFFICIENCY CARRYOVER MECHANISM

Under an efficiency carryover mechanism, a regulated business is permitted to carry over efficiency gains (cost reductions) from one regulatory period to the next. Such an approach enhances the incentive for the regulated business to make efficiency gains by removing the timing distortions that may exist without such a mechanism.

Under a CPI-X regulatory regime, regulated businesses have an incentive to improve their efficiency within a regulatory period, as allowed price changes within the period are not linked to actual costs. In the absence of an efficiency carryover mechanism, a regulated business has a stronger incentive to achieve efficiencies in the early part of the regulatory period than it does in the latter part of the regulatory period. This is because it is able to retain the benefits of any underspend relative to the expenditure benchmarks that underpin prices for a longer period of time. The benefits from generating efficiencies at the end of the regulatory period would only be retained by the business for a brief period if the regulator sought to pass on those benefits to consumers at the next price reset, through lower prices. The business may be inclined to delay making efficiency gains in the later years of the regulatory period, until early in the following regulatory period.

The efficiency carryover mechanism removes this timing incentive by allowing the regulated business to retain any efficiencies for the same length of time, regardless of when those efficiencies are generated.

In December 2002 the Commission released a discussion paper[68] on the efficiency carryover mechanism. The Discussion Paper raised various questions and issues relating to the proposed structure of the efficiency carryover mechanism.

Following this the Commission released its Working Conclusions[69] on the efficiency carryover mechanism, in April 2003. The paper presented the Commission's working conclusions in relation to the issues and questions raised in the Discussion Paper, taking into account the views put forward by respondents in their submissions to the Discussion Paper.

This chapter gives an overview of the design of the efficiency carryover mechanism that the Commission has applied to efficiency gains made in the initial regulatory period (2000/01 to 2004/05) and shows, in Table 6.1, the amounts to be carried over from the initial regulatory period to the 2005-2010 regulatory period.

Section 6.4 (Subsequent Regulatory Period) discusses the action the Commission proposes to take in regard to efficiencies generated in the subsequent regulatory period.

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68 Electricity Distribution Price Review: Efficiency Carryover Mechanism – Discussion Paper, December 2002, (http://www.escosa.sa.gov.au/resources/documents/021216-R-EffCarryover_DiscPaper.pdf)

69 Electricity Distribution Price Review: Efficiency Carryover Mechanism – Working Conclusions, April 2003, (http://www.escosa.sa.gov.au/resources/documents/030407-R-FinalEffCarryWC.pdf)

6.1 The Commission's decisions on the design of the efficiency carryover mechanism

This section discusses the design of the efficiency carryover mechanism adopted by the Commission to apply to efficiency gains or losses in the 2000-2005 regulatory period.

In designing the efficiency carryover mechanism, the Commission was required to have regard to a number of legal obligations set out in the ESC Act and the EPO.[70]

The Commission has also had regard to the need to promote all aspects of efficiency, that is, productive efficiency, allocative efficiency and dynamic efficiency.

6.1.1 Efficiency gains and losses

Under the EPO, the Commission is required to have regard to the need to offer ETSA Utilities a continuous incentive to improve efficiency[71] in:

i. The utilisation of existing capital assets;

ii. The acquisition of prescribed transmission services;

iii. Operating expenditure; and

iv. Capital expenditure.

6

Asset Utilisation and Transmission Services

For the reasons set out in the Working Conclusions Paper, the Commission has not treated efficiencies in asset utilisation separately from efficiencies in operating or capital expenditure, and has treated transmission service costs as a pass through amount under the EPO.

The Commission has, therefore, only considered efficiencies in operating and capital expenditure. The following discussion sets out the Commission's methodology in regard to its treatment of efficiencies in operating and capital expenditure.

Measurement of efficiency gains

An efficiency gain is defined as the difference between the benchmark expenditure forecasts established for capital and operating expenditure at the outset of the regulatory review period, and the actual capital and operating expenditure outcomes over that regulatory period.

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70 For detailed discussion on these obligations refer, Electricity Distribution Price Review: Efficiency Carryover Mechanism – Discussion Paper, December 2002 (http://www.escosa.sa.gov.au/resources/documents/021216-R-EffCarryover_DiscPaper.pdf) .

71 Electricity Pricing Order, clause 7.2(h)(i), p.33.

Operating Expenditure

The Commission has used the incremental approach in calculating efficiency gains or losses for operating expenditure against the benchmark cost for operating expenditure. Under an incremental approach, only the additional improvement in efficiency in a given year, over and above the improvements that have been achieved through initiatives in previous years, are captured.

The reason for this is that operating expenditure exhibits a strong correlation from year to year, unlike capital expenditure, which is more variable from year to year.

The incremental approach assumes that the efficiency savings made by the business are permanent savings. Any one-off savings achieved by the business may be treated as an efficiency gain in one year, but this would be offset by an efficiency loss in the following year since the savings would not be sustained. If the incremental approach was not adopted for operating expenditure, the customer would not receive any part of the efficiency benefit as the business would keep the full value of any temporary underspend in perpetuity.

Capital Expenditure

The Commission's calculation of capital expenditure gains differs from its calculation of operating expenditure gains in that, due to the primarily project based nature of such expenditure, capital expenditure efficiency gains or losses have been computed against the benchmark costs in every year of the regulatory period, regardless of the previous year's capital expenditure level. The distributor will be allowed to earn a return on the efficiency amount for each year, over a five-year carryover period.

Further to this, the Commission has not included a component in the efficiency calculation for capital expenditure to reflect savings in depreciation[72].

6.1.2 Management induced versus External Efficiency Gains

Differential treatment of management induced versus external efficiency gains

Clause 7.2(h) of the EPO requires the Commission to have regard to the desirability of rewarding ETSA Utilities for efficiency gains, especially where those gains arise from management initiatives. As noted in the Discussion Paper, this suggests that the Commission may treat efficiency savings achieved by management differently from those achieved due to exogenous factors.

[72] See page 11 of the Working Conclusions Paper for a full explanation of why the Commission has not included depreciation in the carryover mechanism (http://www.escosa.sa.gov.au/resources/documents/030407-R-FinalEffCarryWC.pdf).

However, while it is desirable to distinguish between the two, in practice it is likely to be difficult. For this reason, the Commission has not differentiated between management induced and external efficiencies.

Adjustment for changes in external cost drivers

It was noted in the Discussion Paper that business expenditure will be impacted both by changes in demand and changes in the scope of services that ETSA Utilities is required to provide. Where actual connection numbers are greater than forecast, or where the scope of ETSA Utilities' obligations is increased, it is likely that both the operating and capital costs incurred by ETSA Utilities will be greater than first expected.

One way of dealing with such factors is to adjust prior year benchmarks to account for any difference in demand or in the scope of obligations. The Commission has decided only to adjust the benchmark costs against which efficiency is assessed where there have been material changes to costs due to pass through events (as permitted under the EPO), and where the amount of those costs has been approved by the Commission. The Commission has further decided, in the interests of pragmatism, not to make adjustments to account for any differences between forecast and outturn growth.

6.1.3 The Mechanism

The two most common efficiency carryover mechanisms are:

- The rolling carryover mechanism; and
- The glide path mechanism.

After considering the submissions to the discussion paper, the Commission does not consider that the glide path approach meets the EPO requirement to provide a 'continuous incentive'. Under this approach, the distribution business does not have a continuous incentive to achieve efficiency gains in each year of the regulatory period, as the gains made in the initial years are glided out over the whole of the subsequent period, not just the first few years as they would under a rolling carryover mechanism. This continues to provide the distributor with an incentive to make efficiency gains in capital expenditure in the early years within a regulatory period.

For this reason, the Commission has adopted a rolling carryover mechanism for efficiencies generated in the initial regulatory period. Under the rolling carryover mechanism, the distributor is permitted to retain any efficiency gains or losses for a specified number of years following the year in which they were incurred.

Appropriate sharing ratio

The Commission considers that the concept of a fair sharing ratio needs to take into account the trade-off between the extent of the efficiency savings made and the speed with which those savings are passed onto consumers.

On this basis, the Commission has decided that it is appropriate to allow ETSA Utilities to retain efficiency gains or losses for 5 years after those efficiency gains or losses are made. This will result in ETSA Utilities retaining approximately 30% of efficiency gains.

Symmetrical treatment of gains and losses

The EPO requires that efficiency gains achieved be shared between distributors and consumers, but makes no specific reference to efficiency losses. The Commission is of the view that if efficiency losses are disregarded from the calculation of an efficiency carryover, then the exclusion of such losses could distort the incentive for distributors to achieve efficiency gains in each year of a regulatory period.

Therefore, the Commission has implemented a symmetrical scheme, whereby both efficiency gains and losses have been considered in the carryover.

Treatment of negative carryovers

In its Working Conclusions the Commission decided that, in order to negate any risk that ETSA Utilities could be exposed to a negative carryover amount under the rolling carryover mechanism if the efficiency gains it has achieved to date in operating expenditure turn out to be temporary, it would set the carryover amount to zero if the carryover mechanism resulted in a net negative carryover for the 2000-2005 regulatory period.

As discussed in Section 6.3, the amount calculated in respect of efficiencies generated in the 2000-2005 regulatory period was negative and therefore the carryover amount for the 2005-2010 regulatory period has been set to zero.

Neutrality between operating and capital expenditure

For reasons outlined in its Working Conclusions Paper, the Commission has decided that the issue of capex/opex substitution for on-going savings in capital expenditure is not a material issue for the purpose of setting up the efficiency carryover mechanism.

Therefore, the efficiency carryover mechanism does not have any additional factors to address a bias against making on-going savings in capital expenditure incorporated into it.

6.2 Interaction with setting benchmarks

6.2.1 Efficiency gains in the last year of the regulatory period

It was noted by the Commission in the Discussion Paper that in calculating the efficiency gain for the 2000-2005 regulatory period, information on actual expenditure performance for 2004/05 (the last year of the 2000-2005 regulatory period) would not be available.

In order to ensure that ETSA Utilities continues to have an incentive to make efficiency gains in the final year of the regulatory period, the Commission has adopted the following method of treating the final year.

For operating expenditure, actual expenditure in the last year of the regulatory period has been assumed equal to expenditure in the previous year, multiplied by the change in efficiency embodied in the original expenditure benchmarks between those years.

For capital expenditure, actual expenditure in the last year of the regulatory period has been assumed to be equal to the benchmark expenditure of that year, and the asset base has been rolled forward on this basis. Any difference between actual and benchmark capital expenditure in this final year will be adjusted in the calculation of the asset base at the start of the subsequent regulatory period, in the 2010 price review.

6.3 Efficiency Carryover Amount from Initial Regulatory Period to Subsequent Regulatory Period

Table 6.1 illustrates the calculation of the efficiency carryover amount to be carried over to the 2005-2010 regulatory period. Based on this calculation, ETSA Utilities has produced negative efficiency carryover amounts for most years and the Commission has therefore included a net carryover amount of zero in accordance with its Working Conclusion regarding the treatment of negative carryovers. This result has been reflected in the Commission's "building blocks" for determining aggregate revenue requirements for ETSA Utilities in the 2005-2010 regulatory period.

It should be noted that EPO benchmarks used to calculate the efficiency carryover have been adjusted to reflect historic CPI, given that the EPO benchmarks had an assumed 2.5% inflation built into them. The benchmarks and actual costs also exclude transmission charges and pass through amounts.

Table 6.1: Calculation of efficiency amount to be carried over to the subsequent regulatory period

Operating & Maintenance Expenditure

	Initial Regulatory Period					Subsequent Regulatory Period				
Year	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
O&M - Benchmark (as per EPO)	101.90	89.70	87.00	86.90	87.10					
O&M - Benchmark (CPI adjusted)	100.65	88.86	89.12	89.39	90.42					
O&M - Actual (excl. TUOS & pass throughs)	88.01	81.40	86.60	96.81	97.04					
O&M - Underspend/Overspend	12.64	7.46	2.52	-7.42	-6.61					
O&M - Incremental Change	12.64	-5.18	-4.94	-9.94	0.81					
Carry Over in Respect of Year 1		12.64	12.64	12.64	12.64	12.64				
Carry Over in Respect of Year 2			-5.18	-5.18	-5.18	-5.18	-5.18			
Carry Over in Respect of Year 3				-4.94	-4.94	-4.94	-4.94	-4.94		
Carry Over in Respect of Year 4					-9.94	-9.94	-9.94	-9.94	-9.94	
Carry Over in Respect of Year 5						0.81	0.81	0.81	0.81	0.81
O&M Efficiency Carry-over to be added to Target Revenue						**-6.61**	**-19.26**	**-14.07**	**-9.13**	**0.81**

Capital Expenditure (Net of Customer Contributions)

	Initial Regulatory Period					Subsequent Regulatory Period				
Year	**2000/01**	**2001/02**	**2002/03**	**2003/04**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**
Capex - Benchmark (as per EPO)	80.90	78.40	77.20	78.70	80.70					
Capex - Benchmark (CPI adjusted)	79.91	77.66	79.08	80.96	83.78					
Capex - Actual (excludes pass throughs)	72.02	81.55	69.54	98.18	80.70					
Capex - Underspend/Overspend	7.89	-3.89	9.54	-17.22	3.08					
Capex - Return (WACC 8.26%)	0.65	-0.32	0.79	-1.42	0.25					
Carry Over in Respect of Year 1		0.65	0.65	0.65	0.65	0.65				
Carry Over in Respect of Year 2			-0.32	-0.32	-0.32	-0.32	-0.32			
Carry Over in Respect of Year 3				0.79	0.79	0.79	0.79	0.79		
Carry Over in Respect of Year 4					-1.42	-1.42	-1.42	-1.42	-1.42	
Carry Over in Respect of Year 5						0.25	0.25	0.25	0.25	0.25
Capex Efficiency Carry-over to be added to Target Revenue						**-0.05**	**-0.70**	**-0.38**	**-1.17**	**0.25**

Annual Efficiency Carry-over to be added to Target Revenue	**-6.66**	**-19.96**	**-14.46**	**-10.30**	**1.06**

Net Overall Efficiency Carry-over amount to be added to Target Revenue	**0.00**

6.4 2005-2010 Regulatory Period

At this stage the Commission envisages that the efficiency carryover mechanism to be applied to efficiency gains generated in the 2005-2010 regulatory period will be similar to that applied to efficiency gains generated in the 2000-2005 regulatory period. There are some design issues that the Commission intends to consult on prior to finalising the scheme for the 2005-2010 regulatory period.

In order to provide ETSA Utilities with some degree of certainty as to how efficiencies generated in the 2005-2010 regulatory period will be treated, the Commission intends to release a guideline in 2005 specifying the exact operational details of the efficiency carryover mechanism, including:

- the manner in which the efficiency carryover amount will be calculated at the end of the 2005-2010 regulatory period (ie will negative amounts be carried forward); and
- how that amount will be carried over to the following regulatory period.

7 CAPITAL EXPENDITURE

A critical input in determining ETSA Utilities' aggregate annual revenue requirement under a building block approach is the Commission's determination of the efficient level of expenditure required to provide prescribed distribution services over the 2005-2010 regulatory period.

The building block formula calculates a forward-looking revenue benchmark by summing efficient expenditure requirements, a return on the regulatory asset base (or the businesses investment) and an amount reflecting depreciation. Any revenue earned under incentive arrangements is also added to determine the annual revenue requirements.[73]

Capital expenditure is used as an input to roll-forward ETSA Utilities' regulatory asset base into the 2005-2010 regulatory period. This is then used to calculate the return on assets and depreciation components of the building block. These two components jointly account for around 70 per cent of ETSA Utilities' total aggregate annual revenue requirement.

This chapter discusses the Commission's consideration of ETSA Utilities' actual capital expenditure in the current regulatory period and its forecast capital expenditure over the 2005-2010 regulatory period. Actual expenditure is used to roll-forward the regulatory asset base to 1 July 2005 and the total asset base in any year is used to calculate the return on assets and depreciation components of the building block from this date.

The Commission's consideration of operating expenditure requirements is discussed in chapter 8.

7.1 Process

The Commission engaged PB Associates (PBA), the Electricity Supply Industry Planning Council (ESIPC) and PKF Accounting (PKF) as independent experts to review certain aspects of ETSA Utilities' expenditure submission. The Commission also established a Working Group comprised mainly of Consumer Advisory Committee members to provide input into the process of determining appropriate expenditure benchmarks.

7.1.1 PBA review

The Commission engaged PBA to provide expert and independent advice on appropriate expenditure benchmarks to apply over the 2005-2010 regulatory period. PBA sought to determine the expenditure that a distributor acting efficiently would require to provide prescribed distribution services in South Australia.

PBA were required to review efficiency in two parts. The first relates to whether ETSA Utilities' proposed expenditure is prudent, or required to meet the

[73] See chapter 11 for a discussion of the building block approach.

distributor's various obligations in accordance with good electricity industry practice. The second is whether the expenditure reflects the lowest sustainable cost over the long term.

ETSA Utilities submitted to the Commission on 14 May 2004 its views on appropriate capital and operating expenditure requirements for the 5 years from July 2005. This submission was presented in line with an agreed information set that would enable PBA to adequately review the efficiency of ETSA Utilities' proposals.

The expenditure information set required by PBA evolved over time as certain issues arose during the review period. PBA held interviews with relevant ETSA Utilities' staff to gain a more thorough understanding of the business and the proposed costs. These interviews were conducted on a continual basis throughout the PBA review.

PBA undertook an extensive review of all aspects of ETSA Utilities' proposed capital expenditure. This included a detailed assessment of the efficiency of the capital projects proposed by ETSA Utilities based on forecast levels of peak network demand and the average service standards set by the Commission.

With regard to the latter, the recommendations made by PBA were on the basis that overall expenditure has a neutral impact on the service levels to be provided by ETSA Utilities. This is consistent with the Commission's decision to maintain current service levels from July 2005 (as described in chapter 3).

ETSA Utilities prepared its submission on the basis that the proposed expenditures would not improve the service delivered to consumers. ETSA Utilities claimed that some factors would improve service (such as targeted asset replacement) while some would worsen service (such as increasing average asset lives).

PBA provided several draft reports to the Commission prior to completing its final report in October 2004. These drafts were provided to ETSA Utilities for its comment to ensure that it understood the basis for any recommendation made by PBA. This process was also important for ensuring the integrity of the PBA final report.

The final PBA report is publicly available on the Commission's website.

7.1.2 Electricity Supply Industry Planning Council Review

The ESIPC, who provide independent advice on the state of the electricity supply industry in South Australia, were engaged to forecast maximum peak demand on ETSA Utilities' distribution network (see chapter 5). Forecast peak demand is relevant for determining required capacity related capital expenditure.

ESIPC provided its final report to the Commission on peak demand in March 2004. Peak demand forecasts are used to determine the extent of network augmentation

required. ETSA Utilities based its capital expenditure on meeting its own peak demand forecasts, which were slightly lower than that forecast by ESIPC.

7.1.3 PKF review

Corporate overheads relate to those administrative costs that are not directly attributed to a particular part of the ETSA Utilities' business. PBA were required to advise on the *total quantum* of corporate overheads while PKF were engaged to advise on the *allocation* of corporate overhead costs.

The PKF advice included how the corporate overheads should be allocated to the regulated and unregulated parts of the business and between capital and operating expenditure. This advice impacts the expenditure benchmarks given it relates to the amount of overheads that should be allocated to certain business functions.

This advice has been used to inform the total expenditure benchmarks set by the Commission.

7.1.4 Consumer Advisory Committee review

The Consumer Advisory Committee Working Group ("the CACWG") consisted of several CAC members plus other interested parties. The CACWG was assisted by Burns Row Worley to provide a submission to the Commission on the appropriate capital and operating expenditure benchmarks.

The CACWG and its consultant had access to the PBA draft report and held discussions with ETSA Utilities and PBA on various aspects of the review. The CACWG submission was provided to the Commission at its last meeting in early October 2004.

7.1.5 Issues Paper

The Commission released ETSA Utilities' submission, along with an Issues Paper, in June 2004.[74] The Issues Paper highlighted the Commission's views on the major issues that stakeholders should consider when reviewing ETSA Utilities' submission. Interested parties were invited to comment on the matters raised in the Issues Paper and ETSA Utilities' submission.

7.2 Current capital expenditure

Part of the information submitted by ETSA Utilities related to the actual expenditure that it incurred over the 2000-2005 regulatory period. This information is required to adjust ETSA Utilities' asset base for additions, depreciation and inflation and to assess the reasonableness of forecast expenditure for the 2005-2010 regulatory period.

[74] *ETSA Utilities' Capital and Operating Expenditure Submission 2005-2010: Issues Paper*, June 2004 (refer http://www.escosa.sa.gov.au/resources/documents/040607-R-ETSAUtilitiesCAPEXOPEXIssuesPaper.pdf) .

7.2.1 Efficiency of current expenditure

The Commission has accepted ETSA Utilities' actual capital expenditure in the 2000-2005 regulatory period as prudent and efficient. This means that ETSA Utilities' regulatory asset base will be adjusted by the full amount of capital spent over the 2000-2005 regulatory period.

This decision is primarily based on the requirements of the Electricity Pricing Order ("the EPO"), which prevents the Commission from undertaking an ex-post assessment of whether ETSA Utilities' past expenditure was efficient.[75] ETSA Utilities' actual capital expenditure in the current regulatory period will therefore be rolled-in to the regulatory asset base.

In addition to this, the Commission considers that the decision to accept actual expenditure as efficient is justified on the basis of the incentive arrangements that apply to ETSA Utilities' expenditure. These arrangements include the CPI-X incentive based regulation and efficiency carryover mechanism that influence ETSA Utilities' expenditure.

CPI-X regulation provides incentives for ETSA Utilities to outperform the expenditure benchmarks that underpin its prices. This is because ETSA Utilities' can retain the benefit of any underspend relative to the benchmarks for the remainder of the regulatory period (as it is able to earn a return on capital that has not been invested).

However, the incentive for ETSA Utilities to achieve efficiencies reduces over the regulatory period. This is because the period over which efficiency gains are retained decreases the further into the regulatory period the gains are made. Regulators typically pass these benefits through to consumers when prices are next reset.

The efficiency carryover mechanism strengthens the incentives for efficient behaviour as it allows ETSA Utilities to retain any efficiency gains (or losses) for a set period of time. The efficiency carryover mechanism introduced by the Commission allows ETSA Utilities to retain efficiency gains for a 5 year period (the scheme is explained in more detail in chapter 6).

The Commission has applied the efficiency carryover mechanism to ETSA Utilities' actual expenditure in the 2000-2005 regulatory period. This yielded an efficiency carryover amount of zero for the 2005-2010 regulatory period, which was driven by higher actual expenditure than forecast. The Commission decided that negative amounts would not be carried over into the 2005-2010 regulatory period.

As explained in more detail in chapter 6, such an asymmetric approach to the treatment of efficiencies in the 2000-2005 regulatory period might not apply in

[75] See clause 7.2(e) of the EPO.

respect of efficiencies made in the 2005-2010 regulatory period. The efficiency carryover mechanism could allow negative efficiencies to be carried forward into future regulatory periods.

The Commission is satisfied that the incentives that apply to ETSA Utilities' expenditure in the current regulatory period would drive efficient behaviour. The Commission has therefore not undertaken any additional analysis of the prudency or efficiency of ETSA Utilities' actual capital expenditure.

The Commission cannot include actual capital expenditure for 2004/05 given that the final price determination is made in March 2005. Given this, the Commission has decided to include the benchmark capital expenditure plus pass through amounts for the purpose of rolling-forward ETSA Utilities' regulatory asset base to 1 July 2005.

7.2.2 Actual versus benchmark capital expenditure

ETSA Utilities' actual capital expenditure in the 2000-2005 regulatory period has been considered relative to the expenditure benchmarks that underpin its prices. Consistent overspending might provide some support for increasing the expenditure benchmarks going forward and vice versa for consistent underspending.

Figure 7.1 compares actual capital expenditure incurred by ETSA Utilities between 2000/01 and 2003/04 to the benchmarks set in the EPO. Gross capital expenditure is separated between expenditure incurred by ETSA Utilities (net capex) and capital contributions from customers towards new and upgraded connection points.

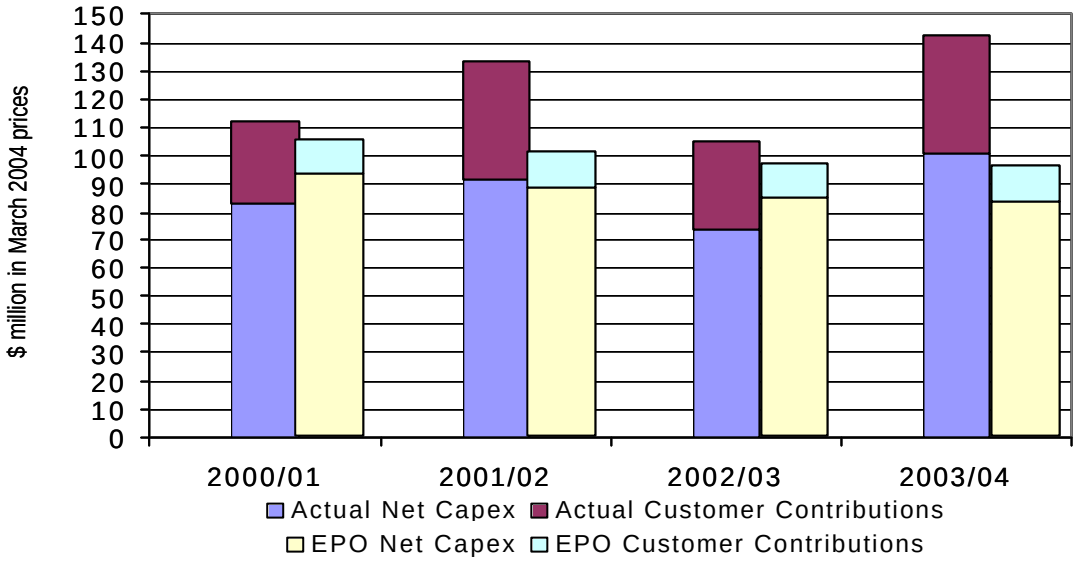
Actual capital expenditure (gross and net) includes work-in-progress but excludes approved pass-through expenditure so that it can be compared with EPO forecasts. This comparison shows that ETSA Utilities' net capital expenditure over the period was around 1% higher than the EPO benchmark, driven largely by a higher than forecast net capital expenditure in 2003/04.

Importantly, the impact of disposals has not been included in this analysis. The value of ETSA Utilities' disposals was around $11 million between 2000/01 and 2003/04. Subtracting disposals from ETSA Utilities' net capital expenditure would result in capital expenditure levels below the EPO benchmarks.

The higher gross capital expenditure on the distribution network was driven by a significant increase in customer contributions on the distribution network.[76] The customer contributions received by ETSA Utilities were 3 times higher than that forecast by the EPO, which drove gross capital expenditure 25% higher than expected under the EPO.

[76] There was a significant increase in customer initiated works on the distribution network from the levels anticipated when the EPO was established. This increase explains the higher than expected amount of customer contributions.

Figure 7.1: ETSA Utilities' net capital expenditure, 2000/01 – 2003/04
($ millions in March 2004 prices)



7.3 ETSA Utilities' forecast capital expenditure

ETSA Utilities submitted that its current capital expenditure allowances are amongst the lowest in Australia. Despite these low allowances, ETSA Utilities claimed that it has delivered excellent service to customers and significantly improved its safety and environmental performance and employee satisfaction.

However, ETSA Utilities believes that current capital expenditure levels are not sustainable in the future. ETSA Utilities argues that it has exploited every avenue for cost reductions, productivity improvements and expenditure deferrals and that it is in the long-term interests of South Australian electricity consumers that expenditure levels increase.

ETSA Utilities also noted that the current levels of capital expenditure were possible over the 2000-2005 period due to the excess capacity that existed in the network at the time of privatisation. ETSA Utilities states that such excess capacity is no longer available and additional expenditure is required to expand capacity to meet future peak demand growth.

ETSA Utilities submitted that low levels of current investment have increased average asset ages and led to a real reduction in the value of its regulatory asset base over the current regulatory period, despite growth in customer numbers. ETSA Utilities believes that current expenditure levels are unsustainable if service levels are to be maintained.

ETSA Utilities therefore proposed that its capital expenditure increase from $535 million in the current regulatory period to $850 million over the 2005-2010 regulatory period, which represents an increase of 60% from current levels.

Table 7.2: ETSA Utilities' proposed capital expenditure, 2005/06 to 2009/10 ($ millions in March 2004 prices)

	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
ETSA Utilities' proposed capital expenditure	166.6	168.4	163.6	167.2	184.0	849.8

ETSA Utilities submitted that this expenditure is required to provide sufficient network capacity to meet forecast peak demand growth, to address the issue of ageing assets and to maintain service levels. ETSA Utilities stated that its proposed expenditure would still see it have low expenditures relative to other Australian distributors.

7.3.1 Benchmarking evidence

ETSA Utilities' submission included results of some high level benchmarking, which compares current and proposed capital expenditure with comparable information from other distributors in Australia. The Commission has reviewed this information as part of the process of setting expenditure benchmarks.

ETSA Utilities used a range of indicators to illustrate that its current expenditure levels are lower than other distribution businesses in Australia. ETSA Utilities stated that its proposed expenditure plan will move it to the lower end of capital expenditures incurred by other distributors.

PBA examined ETSA Utilities' proposed expenditure against relevant benchmarks as an input into its review process. As part of this analysis PBA found that there are many differences between distributors and operating environments across jurisdictions that limit the usefulness of benchmarking, such as:

- ETSA Utilities' use of stobie poles, which on average have a higher capital cost and longer life compared to wooden poles used by the majority of other distributors;
- ETSA Utilities owns and operates network up to the sub-transmission (66kV) level, while other distributors may or may not operate sub-transmission networks;
- wide variations in customer load and sales growth rates across networks significantly impact expenditure requirements; and
- differences in customer density and load density.

In benchmarking ETSA Utilities' proposed capital expenditure against other distributors, using measures such as capital expenditure as a share of the regulatory asset base and per km of line, PBA agreed that ETSA Utilities' capital expenditure is below the average of distributors in other jurisdictions.

The Commission has assessed the benchmarking outcomes and notes that all indications suggest that ETSA Utilities' expenditure is low relative to other distributors.

The benchmarking undertaken by both ETSA Utilities and PBA suggests that ETSA Utilities would continue to remain at the lower end of benchmarking ranges even if expenditure levels were to increase. This suggests that ETSA Utilities would continue to remain relatively efficient in comparison to other Australian distributors.

The Commission believes that benchmarking alone does not provide an authoritative view on whether the proposed expenditure is prudent or efficient, due to the existence of business and environmental differences between distributors. ETSA Utilities has also noted the different drivers of expenditure, such as peak demand, service standards, network characteristics and legislative requirements.

The benchmarking evidence has therefore been used by the Commission to inform its decisions on expenditure benchmarks rather than as the basis for setting these benchmarks. These benchmarks have been supported by more detailed analysis of the justification for changes in expenditures from current levels, which was the focus of the PBA review.

7.4 Submissions

The Commission received 27 submissions to its Issues Paper on ETSA Utilities' capital and operating expenditure proposals.

Several submissions were concerned that ETSA Utilities did not quantify any benefits that would flow to consumers from the proposed increase in capital expenditure. Following from this, there was concern that there might also be the potential for the Commission to grant ETSA Utilities increased expenditure without identifying associated benefits to consumers.

It was also felt that the low demand and sales growth recommendations put forward by ESIPC implied that an amount of capital well below that proposed by ETSA Utilities was required to manage the network. Some submissions did not believe ETSA Utilities had adequately justified why a step change in expenditure was required.

One submission commented on the interrelationship between ETSA Utilities and the transmission company (ElectraNet SA) in planning for additional capacity to be provided to a region. This submission commented on the different ways that additional capacity could be provided to a region that is capacity constrained.

The submission expressed concern that consumers could pay additional costs if ETSA Utilities receives funding for a project that ElectraNet SA has already been funded for. The submission recommended that the Commission consider the feasibility of introducing a planning mechanism to ensure the effective coordination of these capacity related projects.

It was also claimed that ETSA Utilities did not consider the potential of embedded generation and other forms of distributed generation as an alternative to additional capital

expenditure to augment the network. The benefits of such alternate solutions were outlined, and included improved reliability, lower system losses, environmental benefits and lower capital expenditure.

A number of submissions felt that the asset replacement expenditure submitted by ETSA Utilities would reduce operating expenditure. These submissions claimed that a business operating in a competitive market would usually justify asset replacement on the basis of savings in operating expenditure, noting that ETSA Utilities' operating expenditure was forecast to increase.

The Commission has considered the views expressed in all submissions as part of the process of setting appropriate expenditure benchmarks.

7.5 Commission's considerations

The Commission's task under the NEC is to set efficient expenditure benchmarks for the 2005-2010 regulatory period. The Commission has considered all relevant information in making its decisions, including the various submissions and expert advice received.

The Commission's decisions on the appropriate capital expenditure benchmarks are explained in the remainder of this chapter.

7.5.1 Reinforcements and upgrade expenditure

Reinforcements and upgrade expenditure relates to the capital expenditure required to increase the capacity of ETSA Utilities' network to meet future demand. Relevant projects include connection point and sub-transmission line projects, substations, voltage regulation and other smaller distribution projects.

Capacity expenditure is based on forecast peak demand growth and related capacity deficits on the network. ETSA Utilities' proposal for capacity related expenditure for the 2005-2010 regulatory period ($240 million) represented a 170% increase from that forecast for the 2000-2005 regulatory period ($90 million).

ETSA Utilities submitted that a step change in expenditure is required due to the infrequent and lumpy nature of capacity related expansions. ETSA Utilities supported its proposed expenditure on the basis that any excess network capacity that previously existed was utilised in the 2000-2005 regulatory period and that no major capacity upgrade had occurred over the past 10 years.

A large part of the proposed capacity expenditure relates to connection point and subtransmission line projects. The former is concerned with transferring electricity from the transmission network operated by ElectraNet SA while the latter generally relates to increasing the capacity and interconnection of the distribution network.

ETSA Utilities was required to make assumptions regarding the actions that ElectraNet SA would take to augment its transmission network in order to determine the corresponding connection point and sub-transmission line

expenditure requirements. The Commission considers that ETSA Utilities was faced with considerable uncertainty in determining these expenditure requirements.

This stems from the many possible actions that ElectraNet SA and ETSA Utilities could take to provide additional capacity to parts of the network that are constrained. This could include providing a new transmission connection point and/or the provision of additional transformer capacity at an existing connection point. Each solution potentially has large differences in expenditure for ETSA Utilities.

The Commission considers that the majority of uncertainty relates to the major connection point projects forecast for the Adelaide metropolitan area. This is because such projects are interdependent with actions undertaken by ElectraNet SA. For example, a decision by ElectraNet SA on the location of a new connection point can have a significant impact on ETSA Utilities' costs.

These major connection point projects are also closely related to the sub-transmission line projects. In some cases, these projects could be complementary and in others they could be substitutes. For example, a new connection point project could delay the need to augment an existing sub-transmission line.

In addition, the Adelaide metropolitan connection point projects tend to have the highest costs relative to those projects undertaken in rural areas.

For these reasons, the Commission has decided not to include ETSA Utilities' proposed connection point projects for the Adelaide metropolitan area in its expenditure benchmarks. All subtransmission projects have however been included, given there is less uncertainty associated with these projects.

This determination sets out a separate scheme to allow ETSA Utilities to recover prudent and efficient expenditures for the Adelaide metropolitan connection point projects. This scheme ultimately requires ETSA Utilities to seek Commission approval of any connection point project it considers prudent during the 2005-2010 regulatory period (see chapter 13 for discussion of the scheme).

ETSA Utilities submitted two significant connection point projects and a transformer upgrade for the Adelaide metropolitan area that are due to be commissioned towards the end of 2006.[77] ETSA Utilities has informed the Commission that capital will need to be incurred to meet this timeframe by the start of the 2005-2010 regulatory period, providing 18 months for the additional capacity to be installed.

The Commission has included allowances for these two connection point projects in its expenditure benchmarks. This is because ETSA Utilities would not be able to meet the timeframe for providing the additional capacity if it were to follow the

[77] The connection point projects are for additional capacity augmentations in the southern suburbs and western suburbs. The transformer upgrade is scheduled for the Magill substation.

Commission's new scheme from the start of the 2005-2010 regulatory period. In addition, public consultation will be undertaken in respect of these projects.[78]

The Commission has set benchmarks for the other components of the capacity related expenditure that are lower than the benchmarks ETSA Utilities considered appropriate. This is based on advice from PBA on appropriate unit costs and the deferral of certain projects in relation to rural connection point projects, sub-transmission line projects and substation projects submitted by ETSA Utilities.

With regard to project deferral, PBA believed that certain projects could be delayed without materially impacting the average duration of network outages. PBA stated that more detailed network planning would offer lower cost solutions through load transfers or switching, as opposed to the more costly options proposed by ETSA Utilities (such as capacity additions).

ETSA Utilities had also submitted that additional expenditure should be allowed by the Commission to cater for a heat wave event similar to that experienced in 2000/01, which required significant transformer replacement. PBA suggested that such an event was a 1 in 10 year event rather than a 1 in 5 year event as suggested by ETSA Utilities.

PBA therefore believed that the Commission should allow ETSA Utilities to recover $2 million, rather than the $4 million submitted by ETSA Utilities for transformer replacement. The Commission has accepted the advice of PBA on this issue and included $2 million for transformer replacement if a heat wave event occurs, noting that such an event could potentially occur in the 2005-2010 regulatory period.

The Commission's benchmark expenditure is slightly lower than that recommended by PBA reflecting different views on the amount by which the cost of certain services will increase over the 2005-2010 regulatory period. This difference is consistent for all decisions made by the Commission on prudent and efficient expenditure benchmarks.

Overall, the Commission has allowed for a 113% increase in capacity expenditure for the 2005-2010 regulatory period relative to current levels. The benchmark expenditure set by the Commission is 19% lower than that proposed by ETSA Utilities, which is partly attributable to the removal of some capacity related expenditure accounting for around $13 million (in March 2004 prices).

The capacity related expenditure benchmarks set by the Commission are set out in Table 7.3.

[78] As required by the NEC, ESIPC have been involved in the southern suburbs connection point project given that it has a value greater than $10 million.

Table 7.3: Reinforcements and Upgrade Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Reinforcements and Upgrades	$91.5	$239.3	$208.6	$195.0

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

7.5.2 New customer connections

This expenditure category relates to the enhancement and development of the distribution network to meet increased system loads that arise from customer requests for new or upgraded supply. ETSA Utilities will recover part of these costs through its network charges, with the balance recovered from capital contributions made by those customers that have requested the new or upgraded connection.

The Commission has established policy with respect to capital contributions in Chapter 3 of the Electricity Distribution Code ("Chapter 3"). A new approach to capital contributions, specifically in relation to the establishment of charges for network augmentation, is to take effect from the commencement of the next regulatory period in July 2005.[79]

ETSA Utilities submitted that required capital expenditure on new customer connections over the 2005-2010 regulatory period will be $354 million and customer contributions (net of rebates payable by ETSA Utilities to customers) will total $146 million.

This means that the net capital expenditure associated with customer requests for new or upgraded connection points over the 2005-2010 regulatory period has been forecast by ETSA Utilities to be $212 million. ETSA Utilities has therefore proposed an increase in net capital expenditure of 24% for the 2005-2010 regulatory period relative to current levels.

ETSA Utilities has forecast capital expenditure and customer contributions to grow at a steady pace over the 2005-2010 regulatory period, at rates of 3.2% and 2.9% respectively. The experience of the current regulatory period has been that network capital expenditure has shown considerable variability from year to year rather than a steady trend, reflecting the general fluctuations of economic activity.

Nevertheless, the Commission accepts that it is difficult to incorporate such variability into the expenditure benchmarks.

[79] See: ESCOSA 2004, *'Review of Chapter 3 of the Electricity Distribution Code: Supplementary Determination', Final Consultation Draft*, August 2004, (http://www.escosa.sa.gov.au/resources/documents/040811-D-RevCh3_ElecDistCode_SuppDet.pdf).

The level of capital expenditure forecast by ETSA Utilities for 2005/06 ($66 million) is 12% higher than forecast capital expenditure for 2004/05 ($59 million) as specified in ETSA Utilities' submission. The rationale for this increase has been the subject of particular scrutiny by the Commission.

In developing its proposals ETSA Utilities examined key drivers for such expenditure, including housing growth forecasts, the outlook for interest rates, consumer confidence and likely economic growth. ETSA Utilities assumed that business growth and the economic climate would be maintained at current levels over the 2005-2010 regulatory period.

In estimating capital expenditure and customer contributions over the 2005-2010 regulatory period, ETSA Utilities considered new and upgraded connections within the following three categories:

- minor connections – projects with a cost of less than $20,000;
- major connections – projects with cost of $20,000 or more; and
- underground residential developments (URDs) – private residential sub-divisions.

In relation to minor connections, which include a high proportion of upgrades of existing residential connections, ETSA Utilities has assumed a volume growth of 2.5% per year over the 2005-2010 regulatory period, which is based on current levels. ETSA Utilities also assumed that the ratio of customer contributions to capital expenditure would remain constant at 20%.

The Commission does not believe there to be any reason to dispute ETSA Utilities' proposals for minor connections.

ETSA Utilities also assumed that, in the absence of any change to the method for augmentation charging in the existing Chapter 3 of the Electricity Distribution Code, there would be no growth in the number of major connections over the 2005-2010 regulatory period. The Commission notes that such an assumption is based on continuing strong economic growth over the period from July 2005.

The new method of augmentation charging in Chapter 3, proposed to apply from 1 July 2005, reduces the level of augmentation charges for projects already attracting such charges. ETSA Utilities has argued that this will bring forward new projects that would not have proceeded under the existing augmentation charging method. ETSA Utilities has estimated this will result in additional capital expenditure of $4.6 million.

This explains the majority of the increase in capital expenditure proposed to occur between 2004/05 and 2005/06. However, PBA believe that the value of these new projects would be less than that assumed by ETSA Utilities. PBA recommended an amount of $2.3 million be allowed from 2005/06 for increased capital expenditure associated with such projects, rather than the $4.6m proposed by ETSA Utilities.

The Commission endorses the view of PBA on this matter, together with PBA's estimate of the resultant impact on customer contributions.

The total URD market is estimated to have a value of around $18 million per annum based on current experience. This work is contestable, and ETSA Utilities treats the URD work it wins (about 50% of the total) as capital expenditure. ETSA Utilities assumes that this level of URD capital expenditure will continue throughout the 2005-2010 regulatory period.

Customer contributions (net of rebates) have been calculated by ETSA Utilities in accordance with the new provisions of Chapter 3 of the Electricity Distribution Code. The Commission endorses the forecasts of ETSA Utilities for capital expenditure and customer contributions in relation to URDs.

Overall, the new and upgraded connections expenditure benchmark comprises total expenditure of $338 million and customer contributions of $140 million. The Commission's net capital expenditure benchmark for new and upgraded connections is therefore $198 million for the 2005-2010 regulatory period, which is 19% higher than current levels.

The capital expenditure benchmarks for new and upgraded connections as determined by the Commission are set out in Table 7.4.

7

Table 7.4: Net New and Upgraded Connections Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
New and Upgraded Connections	$167.0	$207.8	$199.4	$198.3

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

7.5.3 Asset replacement expenditure

Forecast expenditure on asset replacement/refurbishment relates to the capital expenditure required to replace or refurbish assets due to age and condition. Assets are either replaced when they reach the end of their useful life or refurbished in order to extend the life of an asset.

ETSA Utilities sought a three-fold increase in asset replacement/refurbishment expenditure relative to current levels. ETSA Utilities claimed that this step change is required to implement a long-term solution to address the growing number of assets reaching the end of their effective lives, which could potentially have significant implications for network reliability.

PBA undertook an extensive review of ETSA Utilities' asset quantities, asset condition, age profile and unit costs in forming its opinion on ETSA Utilities' proposed expenditure. PBA concurred with ETSA Utilities that a step change in expenditure was required given the age profile of its asset base.

PBA were of the view that it would be more prudent for ETSA Utilities to increase the relative amount of refurbishment work. PBA also considered that ETSA Utilities had overstated its unit costs in some areas, and has made the necessary adjustment to its recommendation to reflect this.

The Commission is aware of the requirement for increased levels of asset replacement over future regulatory periods, which stems from the large investments in network infrastructure made in the 1950s and early 1960s. Indeed this issue is common to most distributors in Australia.

The Commission had concerns regarding the ability of ETSA Utilities to manage the step change in capital expenditure over the 2005-2010 regulatory period, including that for asset replacement. The Commission has accepted the views of ETSA Utilities and PBA in accepting that such expansions are feasible.

The Commission also accepts the views of ETSA Utilities and PBA that the proposed expenditure will maintain ETSA Utilities' current risk profile: that is, the considerable increase in replacement expenditure will neither lesson nor increase the risk of network outages.

The Commission accepts the advice provided by PBA that the majority of ETSA Utilities' submitted unit costs are reasonable and should be adopted by the Commission. The Commission also accepts the advice of PBA that it would be more prudent for a greater share of ETSA Utilities' distribution poles to be refurbished rather than replaced.

The Commission is conscious of ensuring that sufficient asset replacement occurs now to ensure the network remains robust for supply into the future. Such asset replacement will also act to maintain current supply reliability to customers, especially larger customers where supply interruptions have a significant financial impact.

The Commission has therefore provided for a 173% increase in ETSA Utilities' asset replacement/refurbishment capital expenditure for the 2005-2010 regulatory period relative to current levels. The Commission's expenditure benchmark is 10% lower than that sought by ETSA Utilities.

The asset replacement/refurbishment expenditure benchmarks are set out in Table 7.5.

Table 7.5: Asset Replacement/Refurbishment Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Asset Replacement/ Refurbishment	$32.3	$97.9	$88.3	$88.1

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

7.5.4 Reliability expenditure

Reliability expenditure is associated with improving network reliability. ETSA Utilities' submission is based on maintaining reliability at current levels, consistent with the Commission's working conclusion not to require ETSA Utilities to improve reliability performance above current levels (see Chapter 3).

Despite this, ETSA Utilities submitted that capital expenditure would need to increase from around $7 million in the 2000-2005 regulatory period to $26 million in the 2005-2010 regulatory period. Part of this increase is due to a proposal to improve supply reliability on Kangaroo Island, pursuant to a direction issued by the Commission.

The Commission considered that the increased reliability (and other) expenditure should improve supply reliability. This was potentially an issue given that the service incentive regime implemented by the Commission provides financial rewards if ETSA Utilities exceeds the average targets, which are based on meeting current levels of reliability (see Chapter 3).

ETSA Utilities submitted that the step change in reliability expenditure included an amount to reduce the number of customers exposed to individual outages by changing the operational configuration of the network. `

Another reason for the higher expenditure submitted by ETSA Utilities was the need to undertake protection reviews. These reviews assess the placement of protection devices on the distribution network to ensure appropriate responses to network outages are initiated by ETSA Utilities.

As discussed earlier, ETSA Utilities has claimed that some expenditure will have a positive impact on reliability while other expenditure will have a negative impact on reliability such that overall reliability is maintained. PBA sought to reduce expenditure where they considered a proposed project was directly aimed at improving service.

PBA did not consider it prudent to increase expenditure on undertaking more protection reviews given the requirement to maintain current supply reliability levels. PBA also recommended that expenditure on replacing liquid fuses on the

high voltage network not be accepted on the basis that an allowance had already been made for this activity under asset replacement expenditure.

The Commission agreed with the recommended expenditure put forward by PBA. To this end, PBA's recommendation is $8 million higher than its final report to reflect the inclusion of additional expenditure to improve reliability on Kangaroo Island. PBA had recommended that the Commission accept this expenditure as prudent in a separate exercise from this review.

The expenditure recommended by the Commission is 130% higher than current levels, or 24% higher if the impact of the additional expenditure on Kangaroo Island is removed. The Commission's expenditure benchmark is 34% lower than that submitted by ETSA Utilities.

The reliability capital expenditure benchmarks set by the Commission are set out in Table 7.6.

Table 7.6: Reliability Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Reliability	$7.5	$26.4	$17.4	$17.4

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

7.5.5 Safety and environmental expenditure

Safety expenditure is targeted at maintaining the safety of ETSA Utilities' distribution network. This includes issues of technical safety, public safety and the safety of ETSA Utilities' workforce. Environmental expenditure concerns expenditure required to ensure that ETSA Utilities meets its environmental obligations.

ETSA Utilities sought a three-fold increase in both its safety and environmental expenditure, despite no additional requirements being imposed. ETSA Utilities has submitted this step increase in expenditure in order to maintain its safety and environmental performance.

PBA considers that the safety program and associated costs submitted by ETSA Utilities are prudent and efficient. This view was based on the information provided by ETSA Utilities and PBA's discussions with the Office of the Technical Regulator, who is responsible for safety issues (including monitoring compliance with relevant legislation).

The Commission has also included in its expenditure benchmarks $2.5 million to replace substation locks, which ETSA Utilities had previously submitted under

operating expenditure. PBA did not include this amount in its final report but recommended to the Commission that it be accepted as prudent and efficient. The Commission has accepted this recommendation.

The Commission notes that the actual assessment of those projects that should be prioritised for safety reasons is ETSA Utilities' responsibility. The Commission is seeking to maintain the existing levels of risk assumed by ETSA Utilities, not direct ETSA Utilities as to which projects should be proceeded with and when.

In the light of the significant increase in safety expenditure, the Commission is considering whether to introduce a monitoring arrangement in respect of ETSA Utilities' safety expenditure. This could be achieved by amending reporting guidelines to facilitate the monitoring of total safety expenditure incurred by ETSA Utilities over the 2005-2010 regulatory period.

The primary reason for the increase in environmental expenditure reflects a 10 year plan by ETSA Utilities to address oil containment at 67 high risk substation sites. PBA recommended that this expenditure proceed on the basis of inspection of selected sites and discussions held with the Environmental Protection Authority in South Australia.

The Commission has accepted ETSA Utilities' proposals for safety and environmental expenditure as prudent and efficient, based on its submitted information and the advice put forward by PBA. The Commission's safety expenditure benchmark is $2.5 million higher than that proposed by ETSA Utilities to reflect the inclusion of the substation locks.

The Commission's decision represents a 360% increase in safety expenditure and a 264% increase in environmental expenditure for the 2005-2010 regulatory period relative to current levels.

The safety and environmental expenditure benchmarks set by the Commission are set out in Table 7.7.

Table 7.7: Safety Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Safety	$2.0	$9.4	$9.4	$11.9
Environmental	$1.6	$5.7	$5.7	$5.7

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

7.5.6 Undergrounding

Undergrounding involves removing overhead poles and placing wires underground. This expenditure is incurred in accordance with the undergrounding scheme contained in the *Electricity (General) Regulations 1996*.

Specifically, part 3A of the *Electricity (General) Regulations 1996* sets out the amount of ETSA Utilities' required expenditure in relation to undergrounding in each regulatory year. In 2000/01 this funding amount was $4.2 million, which is adjusted annually by inflation.[80] This funding is included in ETSA Utilities' current expenditure allowances that underpin its distribution tariffs.

The Commission undertook a consultation process as part of the electricity distribution price review to assess whether it should recommend to the Minister that the amount of undergrounding funding increase for the 2005-2010 regulatory period. The Commission decided as a result of this process to maintain funding at current levels.[81]

ETSA Utilities' submission was therefore based on maintaining undergrounding funding at current levels. The Commission accepted this and has included appropriate allowances in the expenditure benchmarks for undergrounding, fixing the amount at $4.9 million annually.

The undergrounding expenditure benchmarks are set out in Table 7.8.

Table 7.8: Undergrounding Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Undergrounding	$24.3	$24.3	$24.3	$24.3

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

7.5.7 IT Infrastructure

IT infrastructure relates to the purchase and operation of all software and hardware that is required to operate the network business. This includes expenditure required for systems that support the maintenance, control and monitoring of the distribution network as well as the servers, applications and personal computers operated by ETSA Utilities' staff.

80 For 2000/01, PLEC funding was increased by an additional $200,000 to provide for the possible effects of the introduction of GST.

81 See: ESCOSA 2004, 'Approach to Electricity Undergrounding from 2005', Final Report, January 2004, which is available at: www.escosa.sa.gov.au.

Full retail contestability

The introduction of full retail contestability (FRC) in South Australia on 1 January 2003 required some considerable changes in the way ETSA Utilities operated its business. This included the purchase of a new base operating system to store customer information and to facilitate customer transfers.

ETSA Utilities submitted additional expenditure over the 2005-2010 regulatory period to maintain and upgrade its FRC systems. Part of ETSA Utilities' proposal relates to replacing existing customer information software by the end of the 2005-2010 regulatory period and enhancing its business-to-business capability.

The Commission accepts advice provided by PBA that the customer information systems do not need to be replaced in the 2005-2010 regulatory period. The Commission has set the IT Infrastructure expenditure benchmark to reflect this decision.

Outage management system

ETSA Utilities also submitted expenditure for the installation of an outage management system (OMS), pursuant to a direction issued by the Commission.[82] ETSA Utilities submitted additional expenditure from that previously approved by the Commission. These additional costs were related to a refresh of the OMS hardware and the undertaking of a major upgrade of the OMS software.

PBA reviewed the additional expenditure requested by ETSA Utilities and believed that the OMS hardware and software upgrades should be delayed. The Commission has accepted that such a delay would be prudent given that the OMS is not yet operational. The IT Infrastructure expenditure benchmarks have been set accordingly.

SCADA

ETSA Utilities also submitted expenditure to upgrade its supervisory control and data acquisition ("SCADA") system.[83] ETSA Utilities also submitted that additional expenditure is necessary to enhance the infrastructure that supports the SCADA system. This expenditure related to cable replacement, additional remote control capability and enhancements to the network operating centre.

PBA believed there was not sufficient justification for upgrading ETSA Utilities' existing SCADA system. The Commission agrees with this view in the light of

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82 The OMS enables the more accurate measurement of reliability performance for each customer connected to the distribution network. The OMS will allow ETSA Utilities to administer the Guaranteed Service Level scheme to apply over the 2005-2010 regulatory period, which provides financial compensation to individual customers receiving poor service (see chapter 3 for a more detailed account of this scheme).

83 The SCADA system refers to ETSA Utilities' computer systems for capturing and analysing network information, such as outages on the high voltage network. SCADA provides ETSA Utilities with the capability to remotely control its network to mitigate the impact of events such as network outages.

significant expenditure on the SCADA system allowed in the 2000-2005 regulatory period and the lack of any strong network benefits flowing from this expenditure.

PBA did however recommend that the projects identified by ETSA Utilities to enhance the infrastructure supporting the SCADA system proceed. However, PBA did consider that the useful economic life of cable was 45 years rather than 40 years. The Commission accepted this recommendation.

Other IT Infrastructure

Other substantial IT Infrastructure projects proposed by ETSA Utilities included the implementation of:

- a customer relationship management system, which aims to link together all of ETSA Utilities IT systems associated with the management of customers;
- an advanced work planning and scheduling system, which aims to improve workforce productivity by improving work planning and scheduling;
- a drawing management system, which is an electronic based system aimed at improving the management and control of plans and drawings; and
- other minor IT projects, such as security system upgrades, internet enhancements and more general IT office requirements (such as personal computers, printers and photocopiers).

PBA believed that there are significant benefits from installing a customer relationship management system but did not believe this to be prudent for ETSA Utilities' monopoly distribution business, citing the major value of such a system being the winning and management of customers in competitive retail markets.

PBA believed that the installation of the work planning and scheduling system would be prudent, based on the benefits stated by ETSA Utilities. PBA believed that the ongoing maintenance costs associated with the system would be lower than that forecast by ETSA Utilities, particularly in relation to the timing of system upgrades.

PBA accepted as prudent the proposed drawing management system and recognised that such systems are common to many utilities. PBA believed that the installation of the system should be delayed by a year to further scope out how the system should be implemented.[84]

PBA accepted the need for the ongoing maintenance of the multitude of smaller systems and day-to-day applications. However, PBA found in some cases that the

[84] PBA expressed the view that accurately capturing and successfully integrating a diverse range of information sources into a single drawing management system can often be difficult to achieve efficiently and it is not unusual for such projects to be de-scoped or experience cost over-runs as the project progresses and unforeseen difficulties emerge.

unit costs proposed by ETSA Utilities for undertaking minor IT projects were high, and as such, recommended reduced expenditure in this area.

The Commission has incorporated the PBA recommendations into its prudent and efficient expenditure benchmarks for IT infrastructure.

Overall IT Infrastructure

The Commission's IT infrastructure expenditure benchmark is 25% lower than current expenditure. This reduction is primarily attributable to reduced expenditure for FRC and OMS, given that the base systems were established in the 2000-2005 regulatory period. The Commission's decision increased the benchmark expenditure for the more general IT infrastructure (such as photocopiers) from current levels.

The benchmark expenditure for IT infrastructure is set out in Table 7.9.

Table 7.9: IT Infrastructure Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
IT Infrastructure	$143.4	$150.5	$107.7	$107.7

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

7

7.5.8 Other capital expenditure

ETSA Utilities submitted expenditure for a range of other items, including easements, buildings, vehicles, minor office equipment, plant and tools and a requirement to make additional superannuation contributions.

PBA believed that ETSA Utilities' proposed expenditure for easements and vehicles was prudent, citing that its vehicle management process reflected industry best practice. PBA did not consider that the additional expenditure submitted for buildings was justified, and recommended that expenditure remain at current levels.

ETSA Utilities claimed that it needed to increase expenditure to refresh existing plant and tools, stemming from tight regulatory allowances in the past and the projected increase in maintenance in the future. PBA considered additional expenditure on plant and tools to be prudent.

ETSA Utilities claimed that it needed to increase its superannuation contributions from current levels based on advice from the actuary representing the scheme that ETSA Utilities contributes to on behalf of its employees. The actuary advised that the additional contribution is required to maintain a prudent fund surplus.

The Commission accepts the need for increased superannuation payments, based on the advice of the actuary. The Commission requested that ETSA Utilities provide updated advice on appropriate contributions just prior to the release of this draft price determination.

PBA did not consider the additional expenditure for minor office equipment submitted by ETSA Utilities to be prudent. This was on the basis that ETSA Utilities had not provided sufficient justification that this expenditure was additional to that allowed for under IT infrastructure. The Commission agrees with this advice.

The expenditure benchmark set by the Commission for the 'other' categories is 12% higher than current levels. This is due mainly to increased expenditure on plant and tools and the need for ETSA Utilities to increase its superannuation payments over the 2005-2010 regulatory period.

The benchmark expenditure for the other capital expenditure category is set out in Table 7.10.

Table 7.10: Other Capital Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Other capital	$67.2	$88.4	$74.5	$74.5

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

7.6 Summary

This chapter has outlined the Commission's reasons for arriving at the capital expenditure benchmarks, including an explanation of why it has not in some cases accepted the benchmarks proposed by ETSA Utilities. The Commission has considered all relevant information in detail as part of the process of establishing the capital expenditure benchmarks.

The Commission is of the view that the capital expenditure benchmarks provide ETSA Utilities with sufficient revenue to meet the expected growth in peak demand and the service standards obligations. The Commission believes that the benchmarks represent the efficient cost of providing prescribed distribution services pursuant to these obligations.

The Commission has also sought to provide ETSA Utilities with sufficient revenue to implement a long-term strategy for asset replacement. Such expenditure is required to ensure the robustness of the network infrastructure for future years while maintaining current supply reliability to customers.

The prudent and efficient expenditure benchmarks have been established for different cost categories. This reflects the manner in which ETSA Utilities submitted its proposed expenditure requirements and how PBA reviewed this information rather than describing how ETSA Utilities will incur expenditure over the 2005-2010 regulatory period.

The expenditure benchmarks do not dictate the actual amount of expenditure that ETSA Utilities must incur or how ETSA Utilities should direct its expenditure (i.e. on asset replacement or capacity expansions). ETSA Utilities is responsible for managing its daily network operations and it must decide appropriate expenditures to meet its obligations.

The capital expenditure benchmarks set by the Commission are shown in Table 7.11. The Commission has set a total capital expenditure benchmark of $723 million for the 2005-2010 regulatory period, which is 37% higher than current levels.[85] The Commission's capital expenditure benchmark is 15% lower than that proposed by ETSA Utilities.

Table 7.11: Capital Expenditure Benchmarks 2005/06 to 2009/10
($ millions in March 2004 prices)

CAPITAL EXPENDITURE	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
Commission benchmarks	142.5	145.0	141.3	140.6	153.5	722.9
ETSA Utilities proposed	166.6	168.4	163.6	167.2	184.0	849.8
Difference (%)	*-14*	*-14*	*-14*	*-16*	*-17*	*-15*

7

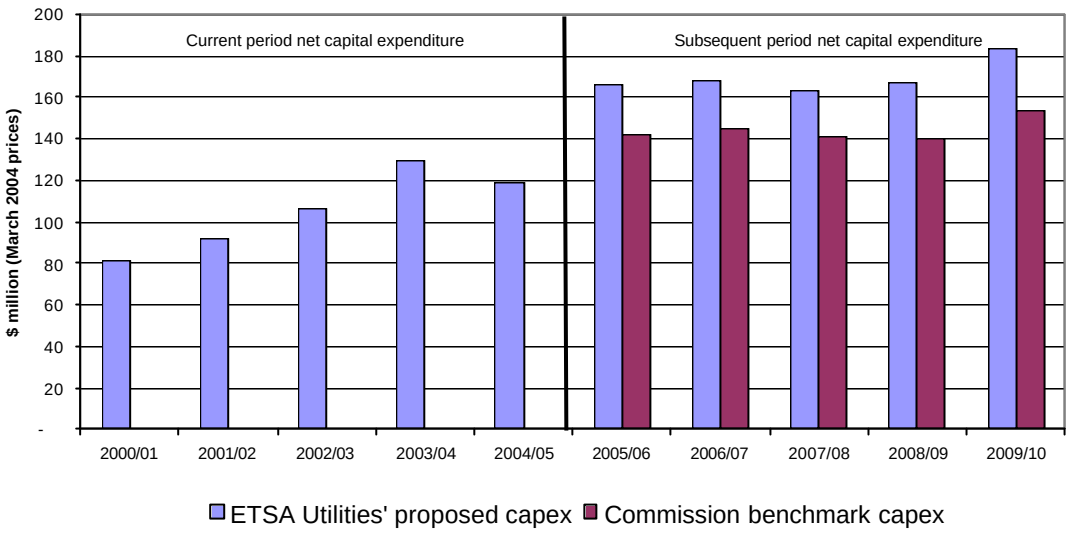
Importantly, the Commission's benchmarks do not include expenditure for some of the major connection point projects in the Adelaide metropolitan area that occur towards the end of the 2005-2010 regulatory period. These projects could account for as much as $13.3 million over the 2005-2010 regulatory period.

While ETSA Utilities had forecast a step change in expenditure, the Commission's expenditure benchmarks reflect a more gradual increase in expenditure over the 2005-2010 regulatory period (Figure 7.2). The Commission believes that the increase in capital investment allowed in this draft price determination will ensure the long-term integrity of the State's distribution network.

To this end, there are many reasons as to why the expenditure benchmarks need to be increased from current levels, as implied by the benchmarking analysis considered earlier in this chapter. This includes the need to expand network capacity to meet future demand growth and to replace ageing assets with newer assets for future use.

[85] Current period expenditure relates to the 2000/01 to 2004/05 period. The 2000/01 to 2003/04 represents actual expenditure while 2004/05 is ETSA Utilities' forecast of expenditure. Total capital expenditure in the current regulatory period was $528 million in March 2004 prices.

Figure 7.2: Comparison of Net Capital Expenditure 2001/02 to 2009/10*
($ millions in March 2004 prices)



* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8 OPERATING EXPENDITURE

As part of the expenditure review process discussed in the previous Chapter, the Commission has considered the level of operating expenditure that it would expect an efficient distributor to incur over the 2005-2010 regulatory period. This review has examined all operating costs relevant to ETSA Utilities' prescribed distribution business, both direct costs and overheads, except for transmission costs which will be treated as an expenditure pass-through.[86]

Consistent with the approach used for capital expenditure, the Commission has accepted operating expenditure incurred by ETSA Utilities during the current regulatory period as prudent and efficient, given the requirements of cl.7.2(e) of the EPO and the incentives created by the current regulatory regime for ETSA Utilities to minimise expenditure in the current period. The Commission has therefore focussed on the forward looking benchmark for operating expenditure from 2005/06 to 2009/10, with focus on those areas where ETSA Utilities' proposed that expenditure should increase above the current levels.

While there were many inputs into the review process, a major input into the Commission's decision on operating expenditure was the PBA review of prudent and efficient expenditure. While the approach used by PBA was described in some detail in Chapter 7, the methodology for reviewing operating expenditure differed to that used for capital expenditure, as discussed below.

8.1 PBA review

The recommendations put forward by PBA on efficient operating expenditure were developed by first establishing a base forecast. This base forecast is derived from 2003/04 expenditure (which has been calculated using actual expenditure incurred by ETSA Utilities for the first half of the 2003/04 financial year and adding projected expenditure for the following six months)[87]. The base forecast was then projected into the 2005-2010 regulatory period by escalating expenditure to reflect increases in the cost of labour, materials and external services. Any forecast variations in expenditure have been added on top of this base forecast, during the years that they are expected to occur. All forecast costs are presented in real dollars ($March 2004).

This approach has been used to reflect the ongoing nature of operating expenditure, which is different to the more project based nature of capital expenditure.

ETSA Utilities' expenditure submission, and the recommendations made by PBA, were prepared on the basis that ETSA Utilities' current levels of service would be maintained.

86 Refer to Chapter 13 for a discussion of the pass-through arrangements during the 2005-2010 regulatory period in respect of transmission charges incurred by ETSA Utilities.

87 Since the PBA review was finalised prior to the end of the 2003/04 financial year, an estimate of expenditure for the latter half of the year was used by PBA to develop the base forecast.

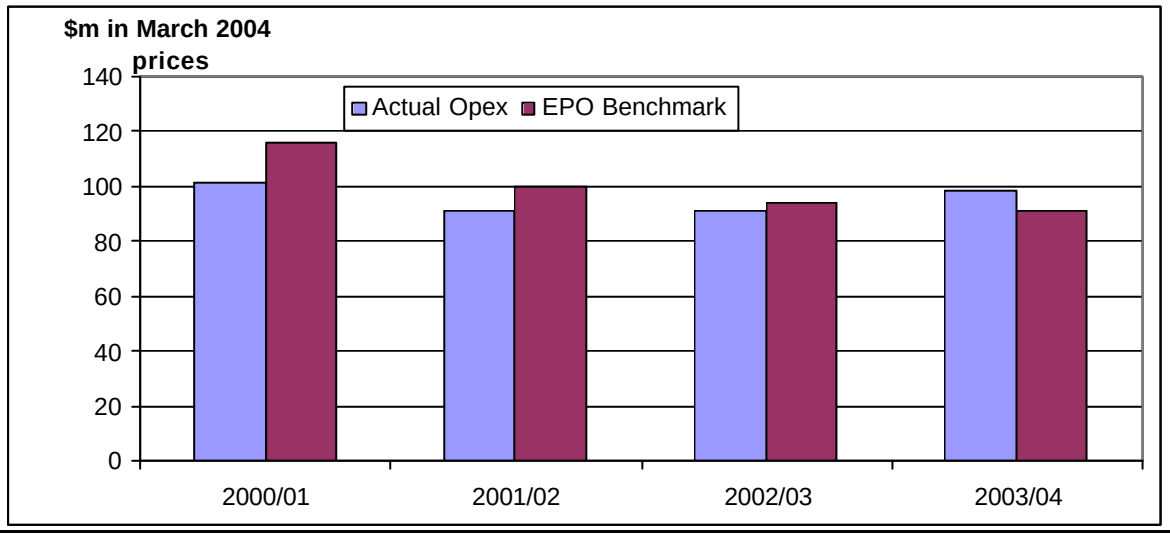
8.2 Current operating expenditure

As discussed above, while the Commission has accepted operating expenditure incurred by ETSA Utilities in the current regulatory period as being efficient, ETSA Utilities' current levels of expenditure still play an important role in determining the forward looking expenditure benchmark. The Commission has examined the extent to which ETSA Utilities' historical operating expenditure differs from the expenditure benchmarks underlying the EPO prices.

Figure 8.1 illustrates that ETSA Utilities' actual operating expenditure between 2000/01 and 2003/04 has generally fallen below the EPO forecasts, with the exception being in 2003/04. Total operating expenditure over the four year period is 4.5% lower than the EPO benchmark. Operating expenditure excludes pass-through expenditure, transmission charges paid by ETSA Utilities and also excludes depreciation expenses.

The Commission does not have access to any breakdown of the EPO benchmark operating expenditure numbers and is therefore unable to determine the specific areas where ETSA Utilities has achieved significant efficiencies compared to the benchmarks.

Figure 8.1: ETSA Utilities' net operating expenditure, 2000/01 – 2003/04
($ millions in March 2004 prices)



ETSA Utilities argues that between 1999/00 and 2001/02, it has been able to reduce its operating expenditure per kilometre of distribution line (expressing operating expenditure in this manner normalises for the size of the network). ETSA Utilities believes that this trend has flattened out in 2002/03 as the scope for efficiencies has been exhausted. ETSA Utilities suggests that the current operating expenditure benchmark is one of the lowest relative to other electricity distribution businesses in Australia. It has argued that it has been able keep within these benchmarks through productivity improvements and cost reductions, which it suggests cannot be sustained in the long run if service levels are to be maintained.

8.3 ETSA Utilities' forecast operating expenditure

ETSA Utilities' expenditure submission proposed a significant increase in operating expenditure compared to current levels. It has argued that an increase in customer expectations and the imposition of new requirements, along with a range of other changes in the commercial and regulatory environment have created the need for increased expenditure.

Some of the key drivers of ETSA Utilities' forecast increase in operating expenditure include the:

- ongoing operating costs to ETSA Utilities arising from the introduction of Full Retail Contestability (FRC);
- need to undertake additional demand management initiatives to address rising peak demand; and
- expansion of the Guaranteed Service Level (GSL) scheme and the requirement to install an Outage Management System (OMS).

Expenditure on these, and other major operating expenditure items, is discussed in section 8.5.

In total, ETSA Utilities has proposed operating expenditure of $746 million in the 2005-2010 regulatory period, which is a 45% increase above the $515m of operating expenditure that is forecast to be incurred over the 2000-2005 regulatory period.

Table 8.1: ETSA Utilities' proposed operating expenditure, 2005/06 to 2009/10 ($ millions in March 2004 prices)

	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
ETSA Utilities' proposed operating expenditure	144.1	145.2	147.7	153.3	155.8	746.1

8.3.1 Benchmarking evidence

It has been noted that the Commission does not consider benchmarking alone to provide an adequate basis for determining efficient expenditure benchmarks, but intends to use benchmarking of ETSA Utilities' current and proposed expenditure relative to other distributors as one input into its assessment. In the case of operating expenditure, differences in regulatory requirements (eg. FRC obligations) could contribute greatly towards differences between the expenditure levels incurred by different distributors. The existence of such differences can make it difficult to draw valid comparisons between businesses. Nevertheless, the Commission has considered the benchmarking presented by ETSA Utilities and PBA in informing its assessment of operating expenditure. PBA's benchmarking confirms the results of ETSA Utilities' own benchmarking, as it suggests that ETSA Utilities' proposed operating expenditure (excluding TUOS) is generally lower than that of other distributors under a range of measures (such as normalising for the

size of the asset base, the length of the distribution network and the number of customers).

The Commission agrees that this benchmarking indicates that, despite the significant increase in operating expenditure submitted by ETSA Utilities, the business would remain relatively efficient in comparison to many other electricity distribution businesses in Australia. While this information may support an increase in expenditure above current levels, the Commission believes that a more detailed assessment of the proposed operating expenditure is necessary to form a view on the efficiency of ETSA Utilities' proposed costs.

8.4 Submissions

Many of the 27 submissions received in response to the Commission's Issues Paper concerning ETSA Utilities' capital and operating expenditure proposals commented on whether ETSA Utilities' community projects, such as event sponsorships, provision of scholarships and education, should be funded through prescribed distribution revenue. Many of these submissions were provided by organisations that currently receive funding from ETSA Utilities, supporting the continuation of prescribed funding. There were, however, other submissions suggesting that it is inappropriate for ETSA Utilities to use prescribed revenue to fund expenditure on these community projects.

Several submissions commented on whether some savings in operating expenditure could be expected given the proposed increase in capital expenditure.

A number of submissions commented on the need to promote greater demand management during the 2005-2010 regulatory period. The Commission's determination on demand management initiatives to be implemented by ETSA Utilities was discussed in Chapter 4. Demand management expenditure is also discussed in section 8.5.10.

8.5 Commission considerations

The Commission has given its consideration to the information provided in all submissions, including those provided by ETSA Utilities and independent experts, and has reached a decision on the efficient operating expenditure benchmarks for the 2005-2010 regulatory period. The Commission has assessed operating expenditure under three broad categories:

1. Directly Attributed Costs

   Approximately half of ETSA Utilities' total operating expenditure consists of direct operating costs, which include:

   - Network Maintenance and Inspections;
   - Vegetation Management;
   - Emergency Response; and
   - Network Operating Costs.

2. New/Non-recurring Costs

   These include costs relating to a number of new obligations imposed on ETSA Utilities. These obligations include:

   - FRC requirements (including provision of certain metering services):
   - the installation and operation of an OMS;
   - administration of a GSL scheme; and
   - obligations imposed by the Commission in relation to demand management.

3. Allocated overheads

   Overheads that are allocated to the prescribed distribution business.

Discussion on these components of operating expenditure is presented in the following sections.

8.5.1 Directly Attributed Costs: Maintenance (including Inspections)

Maintenance costs comprise the costs of ongoing inspection, repairs and maintenance of ETSA Utilities' regulated assets.

ETSA Utilities has submitted its planned asset maintenance operating expenditure for the 2005-2010 regulatory period using the 2003/04 maintenance work program as the base forecast, and incorporating a number of variations to the 2003/04 program where it considers additional expenditure to be warranted. These variations include additional line and substation maintenance to address backlogs of repairs, increased meter investigations required as a result of ETSA Utilities' additional metering responsibilities, and increased inspection activities due to more specific, cost effective targeting of known problem equipment and the ageing of assets.

In its assessment of this expenditure item, the Commission has considered whether operating expenditure on maintenance might be an area where the proposed increase in capital expenditure could deliver future savings.

In relation to this issue, ETSA Utilities has presented the results of modelling it has undertaken which attempts to quantify the extent of any capital and operating expenditure trade-offs. ETSA Utilities concludes that, on the one hand, operating expenditure may be positively correlated with capital expenditure, in that the establishment of additional assets requires additional operating expenditure to maintain those assets. On the other hand, this increase would at least be partially offset by savings resulting from the replacement of assets that are ageing or in poor condition. As shown in Table 8.2, ETSA Utilities forecasts net operating expenditure (opex) increases of $1.6m per annum as a result of its planned capital expenditure (capex). In other words, it argues that there are no net savings in operating expenditure arising from its capital expenditure plans.

Table 8.2: ETSA Utilities' Assessment of the Capex Impact on Network Opex during the 2005-2010 Regulatory Period

OPEX DRIVER	IMPACT	OPEX IMPACT ($M PA)
Capacity and Customer Connections Related Expenditure	Increased size of asset base, driving increased opex, offset by some aged asset replacement.	+1.2
Asset age and condition	Increased failure rates associated with increasing average asset ages and particular asset groups reaching the end of their design lives driving increased un-planned maintenance expenditure.	+0.7
Targeted asset replacement, reliability and maintenance expenditure	Targeted replacement and reliability related expenditure offsetting age-related deterioration thereby assisting to constrain fault related and planned maintenance expenditure.	-0.3
Net Impact		**+$1.6m pa**

Other submissions have presented a contrasting argument on this issue. For example, one submission discussed the implications for operating expenditure from expenditure on asset refurbishment, augmentation and expansion. It argued that capital expenditure related to refurbishment should lead to a significant reduction in operating expenditure. It also argued that capital expenditure related to augmentation should lead to a smaller reduction in operating expenditure and only network expansion should result in increased operating expenditure.

This argument was supported by another submission, suggesting that ETSA Utilities' proposed capital augmentation program should reduce future asset maintenance costs.

Table 8.3 shows a breakdown of ETSA Utilities' proposed capital expenditure by purpose (demand, non-demand and other). It shows that a large proportion of the proposed expenditure relates to the establishment of new connections with smaller proportions relating to augmentation and non-demand issues. Given this breakdown, it is not clear to the Commission whether the net impact on operating expenditure would be positive or negative.

Table 8.3: ETSA Utilities' Proposed Capital Expenditure by Purpose

TYPE OF CAPITAL EXPENDITURE	AS % OF TOTAL CAPITAL EXPENDITURE
Demand related	60% (of which 60% relates to new connections and 40% to augmentation and upgrade of the network)
Non-demand related (eg. reliability of supply, undergrounding and asset refurbishment)	18%
Other (eg. FRC, IT and vehicles)	22%

The Commission believes that there is some uncertainty surrounding the extent of any capital and operating expenditure trade-offs given ETSA Utilities' submitted costs. It acknowledges that the relationship between the two types of expenditure may be positive or negative depending on the nature of the capex. ETSA Utilities'

submission and PBA's assessment are based on the assumption that the relationship is neutral (ie. no explicit trade-off has been assumed), which the Commission considers to be a reasonable approach given the uncertainty.

Having had regard to the above issue and to the submissions provided, the Commission has reached a decision on the efficient maintenance expenditure benchmark, as outlined in Table 8.4.

Table 8.4: Maintenance Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Maintenance	$77.3	$93.2	$75.0	$76.5

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8.5.2 Directly Attributed Costs: Vegetation Management

Vegetation management costs include the costs of inspection and clearance of vegetation from the overhead lines.

ETSA Utilities has contracted out its vegetation management works since the mid 1990s and has been able to achieve ongoing cost savings in vegetation management over the past 5 years. ETSA Utilities' proposed expenditure signals a reversal of this trend.

ETSA Utilities' submitted costs include approximately $9m over the five years to fund the application of more "selective" pruning techniques. ETSA Utilities has included this expenditure in response to increasing pressures to manage community expectations when cutting trees. It has identified an alternative pruning technique to that currently used, which it believes will reduce the visual impact of vegetation clearance and reduce long-term costs by promoting tree growth away from powerlines. This technique is currently being used by a number of businesses in the eastern states.

PBA generally supports ETSA Utilities' current levels of expenditure on vegetation management, on the basis that ETSA Utilities' vegetation management process is at or near industry best practice as a result of advanced pruning techniques and strict contract management. However, it has not recommended the approval of ETSA Utilities' proposal for additional expenditure on developing more selective pruning techniques. While it recognizes the potential benefits from ETSA Utilities' proposal, PBA has concerns over the difficulties in quantifying the customer benefit of improved aesthetics, and the lack of any anticipated benefit to ETSA Utilities of the enhanced approach. It has suggested that further investigation be carried out

on the benefits of ETSA Utilities' proposed approach and has recommended funding for this investigation.

This Commission notes that ETSA Utilities is required under the Electricity Act to undertake vegetation management and that there is a strong incentive for ETSA Utilities to effectively manage vegetation due to the potential impact of overgrown vegetation on the performance of the network. It considers PBA's suggestion to allow for some additional funding to investigate the benefits of an alternative technique to be a reasonable approach to this issue. The Commission's decision on the efficient vegetation management expenditure benchmark is set out in Table 8.5.

Table 8.5: Vegetation Management Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Vegetation Management	$51.1	$54.9	$45.2	$43.3

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8.5.3 Directly Attributed Costs: Emergency Response

Emergency Response costs include the costs of responding to power outages, electrical faults and quality of supply issues.

ETSA Utilities has achieved cost reductions in emergency response during the 2000-2005 regulatory period by improving workforce productivity, reducing material costs and deployment of fault indicators to reduce fault restoration times.

During the 2005-2010 regulatory period it is proposing increased expenditure, primarily through employing additional Trade Skilled Workers (TSWs) in remote country areas, to improve response capabilities and reduce regional response variability.

PBA have indicated their support for the recruitment of additional TSWs, noting it expects the addition of these TSWs to have a major impact on network performance in the regions where they are stationed, particularly on restoration times.

The impact of the additional TSWs on regional network performance raises an important issue. The Commission has determined that average reliability standards during the 2005-2010 regulatory period (including response times) will be set to reflect current performance levels by ETSA Utilities. There is no requirement to improve average reliability standards and it expects ETSA Utilities' expenditure plans to reflect this.

The Commission has discussed this matter further with PBA, who has indicated that it has not reviewed reliability outcomes from the proposed expenditure on a region by region basis. Without a detailed review, it considers that it is not possible to quantify the potential change. It has, however, indicated that an additional 23 TSWs is only a minor increase on current levels.

While the Commission has some concerns that the primary driver for the proposed increase in TSWs is to improve regional response times, which is in conflict with the Commission's desire to maintain current service standards, it is prepared to accept the recommendation from PBA on this issue on the basis that the additional TSWs do not represent a significant increase on current levels.

Table 8.6: Emergency Response Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Emergency Response	$100.6	$96.0	$86.8	$86.0

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8.5.4 Directly Attributed Costs: Network Operating Costs

Network Operating Costs are the costs of managing the distribution network, including network access, monitoring & control, network planning, standards development & maintenance, asset strategy, maintenance planning, maintenance of asset information, network telephony and regulatory liaison.

ETSA Utilities have incorporated a number of variations on top of its base forecast, primarily involving the recruitment of additional staff, eg. due to additional SCADA installed and increased switching requests. PBA have supported the addition of many of these proposed additional staff.

The Commission is prepared to accept the expert advice provided by PBA given the detailed discussions held between PBA and ETSA Utilities on the nature of the additional work required for network operations and the resources required.

The Commission's decision on efficient network operating costs, as set out in Table 8.7, is in line with the 2003/04 level of expenditure.

Table 8.7: Network Operation Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Network Operation	$31.2**	$67.5	$59.7	$59.1

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

** Network Operating costs have only been separately identified by ETSA Utilities since mid-way through 2002/03. Prior to this, the costs were incorporated into overheads, other regulatory categories or in non-regulated categories.

8.5.5 Directly Attributed Costs: Other Costs

These costs relate to the costs of ETSA Utilities' operational facilities including the maintenance of depots and substations. It also includes operational risk and insurance costs such as bushfire insurance.

ETSA Utilities has included additional expenditure of around $800,000 in 2005/06 on top of the base forecast (this figure escalates in future years), which represents an additional self-insurance cost for the deductible of between $1m and $5m for bushfire insurance.

PBA has not supported the additional expenditure for bushfire insurance as it believes that this represents a substantial alteration to the business risk profile of ETSA Utilities. It believes that ETSA Utilities presently self-insures against the deductible and that allowing this as prescribed expenditure would effectively lead to consumers paying twice for it.

ETSA Utilities has responded to this position by suggesting that the deductible represents a real cost to ETSA Utilities. It notes that the Australian Competition and Consumer Commission (ACCC) has indicated in its Statement of Principles for the Regulation of Electricity Transmission Revenue that risk such as that created by the potential for bushfire is not dealt with through the WACC and that self-insurance may be an efficient way of dealing with this risk.

The Commission considers ETSA Utilities' proposal to self-insure against the bushfire insurance deductible to be an important issue of risk management for the business. However, there does not appear to be any material change in circumstance from the 2000-2005 regulatory period that could justify an increase in expenditure above current levels. Therefore, the Commission believes that additional funding for the bushfire insurance deductible is not appropriate.

The Commission considers that expenditure under this category should continue in line with current levels of expenditure. The Commission's decision is set out in Table 8.8.

Table 8.8: Other Directly Attributed Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Other Directly Attributed Costs	$58.6	$70.2	$63.2	$62.6

* 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8.5.6 New/Non-Recurring Costs: Meter Reading costs

As a result of the introduction of FRC, ETSA Utilities is responsible for reading all type 5 and 6 electricity meters in SA. ETSA Utilities has outsourced this function to a private contractor and has established service targets and incentive arrangements in order to reduce the level of estimated reads.

While not reviewing the contract directly, discussions between PBA and ETSA Utilities have led PBA to the view that the meter reading contract entered into by ETSA Utilities and the associated incentive arrangements and contract management and supervision are at or near industry best practice. It supports ETSA Utilities' expenditure forecasts, with the only adjustment being made to reflect PBA's recommended escalation factors.

The Commission accepts the view from PBA regarding ETSA Utilities' meter reading contract and notes that the proposed expenditure for the 2005-2010 regulatory period ($3.8m p.a.) is well below the 2003/04 expenditure ($5.1m p.a.). The Commission's decision is outlined in Table 8.9.

Table 8.9: Meter Reading Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Meter Reading	$8.0	$18.9	$18.4	$17.7

* Note that comparison between expenditure in the 2000-2005 and 2005-2010 regulatory periods may not be meaningful as ETSA Utilities' meter reading requirements are different between the two periods. 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

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8.5.7 New/Non-Recurring Costs: Incremental FRC Operating Costs

ETSA Utilities has included in this category all operating costs associated with its responsibilities arising from the introduction of FRC, other than meter reading. The Commission has allowed ETSA Utilities to recover its FRC costs during the 2000-2005 regulatory period as a pass-through to customers.

In addition to the base forecast, ETSA Utilities are proposing additional expenditure to recruit personnel required to support certain FRC processes.

PBA have accepted ETSA Utilities' proposal for additional FRC personnel. It has noted that, as a result of delays in business to business (B2B) system implementation, the additional staff would not have been required if certain IT programs had delivered the B2B functionality originally anticipated. PBA believes that current complexities in achieving integration across the NEM is such that this functionality will probably not be achieved within the subsequent regulatory period.

The difference between ETSA Utilities' submitted FRC costs and the recommendation by PBA is driven largely by the outcome of PBA's 2002 review of incremental FRC costs.

The Commission has considered all relevant information in reaching a view on the efficient level of incremental FRC expenditure and has decided that the recommendation put forward by PBA may understate the level of expenditure required for ETSA Utilities to fulfil its FRC obligations. The Commission believes that ETSA Utilities' forecast 2004/05 expenditure provides a more reasonable indication of future expenditure requirements and has based its decision on these costs, projected out into the 2005-2010 regulatory period and incorporating the specific variations recommended by PBA.

The Commission's decision on incremental FRC costs is set out in Table 8.10.

Table 8.10: Incremental FRC Operating Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Incremental FRC	$27.1	$79.0	$54.5	$71.3

* Note that comparison between expenditure in the 2000-2005 and 2005-2010 regulatory periods may not be meaningful as ETSA Utilities' FRC requirements are different between the two periods. 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8.5.8 New/Non-Recurring Costs: Outage Management System (OMS) Operating Costs

In July 2003, the Commission notified ETSA Utilities of the requirement to install an OMS, to enable it to more accurately measure network reliability performance and to enable it to administer a GSL scheme. Costs of establishing and operating the OMS were approved by the Commission and treated as a pass through during the 2000-2005 regulatory period. These costs relate to the integration of the OMS with the Geographic Information System (GIS) and the SCADA system. ETSA Utilities' has rolled forward the approved OMS operating costs as the basis for forecasting OMS operating costs in the 2005-2010 regulatory period.

The submitted costs also include expenditure required to run the OMS and existing manual reporting system concurrently over the 2005-2010 regulatory period.

PBA have adjusted the submitted expenditure to reflect advice from the Commission to ETSA Utilities that ETSA Utilities would only be required to run the OMS and existing system in parallel until 31 December 2008, rather that for the entire regulatory period. An adjustment has also been made to the proposed escalation factors.

The Commission approves PBA's recommended expenditure on the OMS during the 2005-2010 regulatory period, noting that the amounts are consistent with the expenditure approved by the Commission in the 2002 pass through application.

Table 8.11: OMS Operating Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
OMS	$0	$6.3	$5.9	$5.8

* Note that comparison between expenditure in the 2000-2005 and 2005-2010 regulatory periods may not be meaningful as ETSA Utilities' OMS requirements are different between the two periods. 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8.5.9 New/Non-Recurring Costs: Call Centre

Prescribed call centre services provided by ETSA Utilities include:

- customer feedback;
- street light outage reporting; and
- faults and emergencies reporting.

Prior to 2003, AGL SA provided these call centre services to ETSA Utilities through a Service Level Agreement (SLA). Since then, these services have been provided by Powercor's Bendigo call centre via an SLA between ETSA Utilities and Powercor. This SLA includes the following key performance targets:

- 85% of all telephone calls responded to within 30 seconds;
- Less than 6% call abandonment rate for the year and less than 10% in any one month;
- Answer and process calls to ETSA Utilities procedures; and
- Less than one complaint relating to advice or attitude provided by an operator per line per month.

The first of these performance targets is currently also an average standard that ETSA Utilities must meet under the Electricity Distribution Code. The Commission intends to retain this standard during the 2005-2010 regulatory period.

ETSA Utilities has advised PBA that the Bendigo call centre is currently meeting the above targets and that it intends to upgrade its capability to ensure that they continue to be met.

ETSA Utilities has also provided PBA with a benchmarking study undertaken by KPMG which indicates that ETSA Utilities' projected call centre costs for 2003/04 of $2.4m are well below the annual benchmark costs of $3m - $3.5m for call centres with comparable call volumes to that of ETSA Utilities.

ETSA Utilities has included one variation in their base forecast of call centre expenditure. ETSA Utilities reports that there has been a 4% increase in the average number of calls received over the 2000-2005 regulatory period from those originally forecast. ETSA Utilities has therefore proposed an initial increase in expenditure of 4%, followed by a 1% increase in expenditure per annum to reflect forecast growth in call volumes (assumed to mirror growth in customer numbers).

PBA have accepted ETSA Utilities' proposed operating expenditure on call centre services, noting that the 2003/04 projected amount of $2.4m compares favourably to similar call centres examined in the KPMG benchmarking study. It supports ETSA Utilities' variation to the base forecasts to reflect the 4% increase in call volumes over the 2000-2005 regulatory period from those originally forecast, and the assumed 1% growth in calls during the 2005-2010 regulatory period.

The Commission's decision on efficient call centre expenditure benchmarks is specified in Table 8.12.

Table 8.12: Call Centre Operating Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Call Centre	$4.4	$13.3	$11.8	$10.8

* Note that comparison between expenditure in the current and subsequent regulatory periods may not be meaningful as ETSA Utilities' call centre requirements are different between the two periods. 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

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8.5.10 New/Non-Recurring Costs: Demand Side Management

The requirements that the Commission intends to impose on ETSA Utilities during the 2005-2010 regulatory period in relation to demand management were discussed in Chapter 4. In summary, the Commission will provide a maximum of $20m funding to ETSA Utilities over this period to implement a number of demand management programs including:

- Power Factor Correction - promoting the installation of power factor correction equipment for those customers on kVA tariffs;
- Standby Generation pilot program;
- Trial of Direct Load Control of residential customers;
- Development of Critical Peak Pricing tariffs for large customers;
- Voluntary Load Control (initiated by retailers/customers); and
- Study into ETSA Utilities becoming a demand management aggregator.

Funding for these programs is to be treated as operating expenditure. Any expenditure above $20m will be at ETSA Utilities' cost and any underspend will not

be treated as an efficiency gain for the purpose of the efficiency carryover mechanism (i.e. the underspend will be returned to consumers).

ETSA Utilities' submitted expenditure on demand management during the 2005-2010 regulatory period totalling $24.8m (or around $5m per year). PBA's assessment of these costs was broadly consistent with ETSA Utilities' proposal.

ETSA Utilities' proposed costs and PBA's assessment, was provided prior to the Commission releasing its draft decision on a $20m funding cap for demand management.

The Commission intends to maintain its position on the appropriate level of funding for demand management initiatives during the 2005-2010 regulatory period and has therefore included a $20m benchmark in operating expenditure for this purpose.

Table 8.13: Demand Management Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Demand Management	$0.3	$24.8	$24.2	$20.0

* Note that comparison between expenditure in the 2000-2005 and 2005-2010 regulatory periods may not be meaningful as ETSA Utilities' demand management requirements are different between the two periods. 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8.5.11 New/Non-Recurring Costs: Guaranteed Service Level (GSL) payments

ETSA Utilities have submitted an allowance of $1.8m per annum for GSL payments based on the Commission's working conclusion regarding the GSL scheme to apply in the 2005-2010 regulatory period. Final details on the GSL scheme were still being discussed between the Commission and ETSA Utilities at the time of the expenditure submission and the allowed funding had not been finalised at the time.

PBA supports the proposed GSL expenditure on the basis of the Commission's recommendation regarding the GSL scheme and funding arrangements.

The Commission's decision on the GSL scheme is discussed in Chapter 3. On the basis of historical data, the Commission has allowed a benchmark operating cost of $1.18m per annum (nominal) for the GSL scheme. Any over or underspending of this amount will be treated as an efficiency loss/gain under the efficiency carryover mechanism.

Table 8.14 converts this amount into March 2004 dollars based on forecast CPI of 2.2%.

Table 8.14: GSL Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
GSL	$0	$9	$9	$5.5

* Note that comparison between expenditure in the 2000-2005 and 2005-2010 regulatory periods may not be meaningful as ETSA Utilities' GSL requirements are different between the two periods.

8.5.12 Allocated Overheads

Allocated overheads have been disaggregated into the following categories, based on ETSA Utilities' corporate structure:

- Finance;
- Corporate Affairs;
- Business Relations;
- Shared Services;
- IT; and
- Other.

ETSA Utilities has proposed a significant increase in corporate overheads compared to current levels of expenditure. Overall, ETSA Utilities is proposing to spend $166m in corporate overheads during the 2005-2010 regulatory period, which is a 31% increase on overheads incurred in the 2000-2005 regulatory period. This increase is stated by ETSA Utilities to be driven by a number of factors, including the need for further resources to meet certain additional regulatory requirements, the desire to provide additional information to consumers associated with ETSA Utilities' customer charter, and the need for additional IT operating expenditure to reflect the proposed increase in IT capital expenditure.

PBA has supported some of ETSA Utilities' proposed variations to corporate overheads, but has recommended an overall reduction in overhead expenditure compared to that submitted by ETSA Utilities. PBA's recommendation does, however, represent a 3% increase above the allocated overheads incurred in the 2000-2005 regulatory period. PBA's recommendation reflects its assessment of prudent and efficient corporate overheads, as well as the methodology for allocating these overheads to the prescribed business. As discussed earlier, the Commission engaged PKF to provide some assistance on this latter issue.

The Commission has agreed that allocated overheads should be allowed to increase from current levels, although it has proposed a reduction in certain areas compared to ETSA Utilities' proposal and PBA's recommendation.

With regard to Business Relations expenditure, the Commission believes that it would be imprudent to allow prescribed revenue to be used to fund activities that are aimed at promoting brand awareness of ETSA Utilities. In the Commission's view, such marketing activity should not be necessary for a monopoly provider of prescribed services. The major beneficiaries of this activity would be ETSA Utilities' unregulated businesses, and the Commission believes it would be detrimental to competition in those markets where ETSA Utilities is active, if ETSA Utilities were able to fund marketing through prescribed revenue.

The Commission is also of the view that, during the 2005-2010 regulatory period, ETSA Utilities should not be able to fund community projects through the use of prescribed distribution revenue. The Commission has had regard to the many submissions provided on this issue in reaching this decision. While the Commission acknowledges that support of community projects is a laudable corporate objective, it is of the opinion that it is not appropriate for South Australian distribution customers to be funding these projects.

The Commission supports expenditure by ETSA Utilities on educating consumers of their rights and obligations and in promoting safety awareness. However, it believes that escalation of current allowances is an appropriate level of funding for this purpose.

The Commission's decision on allocated overheads is set out in Table 8.15.

Table 8.15: Allocated Overhead Expenditure Benchmarks for 2005/06 to 2009/10 ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Allocated Overheads	$127.0	$166.3	$131.4	$137.1

* Note that comparison between expenditure in the 2000-2005 and 2005-2010 regulatory periods may not be meaningful as ETSA Utilities' demand management requirements are different between the two periods. 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8.5.13 Other Costs

ETSA Utilities has submitted approximately $795m under this category, although the majority of these costs are made up of Transmission Use of System (TUoS) charges. These charges relate mainly to the energy delivered into ETSA Utilities' distribution system by ElectraNet SA's transmission system. ETSA Utilities purchases the necessary transmission services (transmission capacity) from ElectraNet SA.

Under the EPO, these transmission costs are treated as 'controllable costs' for ETSA Utilities. This means that the transmission costs are included as benchmark expenditure, providing ETSA Utilities with the incentive to optimise the bundle of transmission services that it purchases. While ETSA Utilities cannot avoid the purchase of transmission services, it may have ability to seek some variation in the way transmission services are provided. Any improvement over the benchmark is treated as an efficiency gain, and hence would be treated in accordance with the efficiency carryover mechanism.

However, making transmission a controllable cost creates some uncertainty given the overlap in the ACCC revenue cap decision with the 2000-2005 regulatory period. For example, retaining transmission services as a controllable cost would require the Commission to set a benchmark transmission cost for the 2008–2010 period as part of the 2005 Price Review, even though the ACCC will not set those controls for some years.

Further, the method that the ACCC uses to regulate ElectraNet SA, in both the 2003-2008 and 2009-2014 periods may not give ETSA Utilities any control over transmission costs. Under the current revenue cap arrangements, ElectraNet SA can recover a certain amount of revenue each year. Any loss or gain due to volume variability will be adjusted in the following year, thus maintaining the overall revenue cap. This reduces the incentive for ETSA Utilities to optimise their purchase, as a reduction achieved in one year would be offset by increased prices in the following year.

The Commission has therefore decided to make transmission costs a direct pass through, whereby ETSA Utilities passes through those transmission costs as they are incurred. This removes any uncertainty referred to above. It also reduces the incentive referred to earlier, although ETSA Utilities may still have some indirect incentive to manage its transmission purchases, insofar as those purchases can effect its own opex and capex requirements.

After excluding TUOS from this expenditure category, approximately $47m of the $795m submitted expenditure under "other" relates to the following items:

- Voluntary Separation Packages (VSPs);
- Employee Bonuses;
- Superannuation; and
- Forward Hedge Costs.

ETSA Utilities has forecast VSPs to be $6.2m over the 2005-2010 regulatory period compared to $3.9m in the 2000-2005 regulatory period (a 59% increase). The forecast is based on extrapolating the estimated 2003/04 VSP costs. ETSA Utilities has advised PBA that there are no specific areas or groups that are targeted for VSPs over the next 5 years.

ETSA Utilities' forecast employee bonuses totalling $9.1m over the 2005-2010 regulatory period, compared to an amount of $10.7m in the 2000-2005 regulatory period (a 15% decrease).

ETSA Utilities has included a forecast $15m expenditure for superannuation and $15m for forward hedge costs over the 2005-2010 regulatory period. Both of these costs are submitted as additional/incremental costs to the business.

The additional superannuation costs are based on an actuarial report prepared in 2004 for the ETSA Utilities Board. ETSA Utilities considers that these costs have been triggered by changes in circumstances such as investment returns, wage growth and anticipated levels of retirees that will take pensions.

The forward hedge costs are based on ETSA Utilities' interpretation of EPO requirements.

PBA considers the extrapolation of the 2003/04 estimate of VSPs to provide a highly uncertain forecast. It does, however, acknowledge that VSPs may be required in certain cases. PBA notes that legislation for the payments of VSPs has been in place since 1999 and that ETSA Utilities is in direct control of business process changes or restructuring that might give rise to the need for VSPs.

It has recommended that VSP expenditure continue in line with costs incurred in the 2000-2005 regulatory period.

PBA supports ETSA Utilities' proposed expenditure on employee bonuses, on the basis that it has recommended a number of changes to ETSA Utilities' submission that have implications for productivity improvements, and as a result of its view that bonuses are an important incentive tool for management.

PBA recognises superannuation and forward hedge costs as legitimate costs for the prescribed business and has therefore recommended recovery of these costs. However, on the basis of advice from the Commission that ETSA Utilities' regulatory return on assets will include an allowance for forward hedge costs, PBA has removed hedge costs from its recommended operating expenditure.

The Commission accepts the recommendation made by PBA for the continuation of current VSP payments. It agrees that there have been no material changes in circumstances which justify any significant increase in VSP payments during the 2005-2010 regulatory period.

The Commission notes that where it is assumed that ETSA Utilities is able to achieve labour productivity gains in the 2005-2010 regulatory period, the existence of employee bonuses can play an important role in driving such improvement. It therefore accepts PBA's recommendation on employee bonuses.

It also accepts PBA's recommendation for additional superannuation costs on the basis that PBA has reviewed these costs and determined them to be necessary for the operation of the prescribed business and to be prudent and efficient. The

Commission has not included forward hedge costs in the expenditure benchmarks as these costs have been addressed through the WACC.

In addition to the above items, the Commission has included two other items in this "other" category, namely:

- Retailer of Last Resort (RoLR) Establishment Costs; and
- Kangaroo Island Reliability Improvement Operating Costs.

These items were not included in ETSA Utilities' submitted costs or PBA's analysis due to uncertainty surrounding the requirements for RoLR and because the Commission has only recently announced its intention to impose separate reliability standards for Kangaroo Island.

In relation to RoLR costs, ETSA Utilities has provided an estimate to the Commission of the potential operating costs it will incur in establishing the capability to provide RoLR services. The Commission has considered ETSA Utilities' proposed costs and has allowed $1m per annum for this item.

The costs of meeting the proposed new reliability target for Kangaroo Island has been the subject of a separate review by the Commission. The Commission has engaged PBA to examine the reliability improvement solution put forward by ETSA Utilities and to provide a recommendation on the efficient costs of providing such a solution. The Commission has included operating expenditure of $174,000 per annum for this item, consistent with PBA's recommendation.

Total other costs included by the Commission in the expenditure benchmark are specified in Table 8.16.

Table 8.16: Other Operating Expenditure Benchmarks for 2005/06 to 2009/10 – excluding TUOS ($ millions in March 2004 prices)

	ETSA UTILITIES' CURRENT EXPENDITURE (2000/01 TO 2004/05)*	ETSA UTILITIES' PROPOSED EXPENDITURE (2005/06 TO 2009/10)	PBA RECOMMENDED EXPENDITURE (2005/06 TO 2009/10)	COMMISSION DECISION (2005/06 TO 2009/10)
Other	$9.0	$46.7	$28.1	$34.0

* Note that comparison between expenditure in the 2000-2005 and 2005-2010 regulatory periods may not be meaningful as ETSA Utilities' demand management requirements are different between the two periods. 2004/05 expenditure represents ETSA Utilities' estimate of expenditure for this year.

8.6 Summary

The Commission believes that its decision on efficient operating expenditure benchmarks for the 2005-2010 regulatory period represents an appropriate balance between the interests of consumers and ETSA Utilities. It has allowed for a real increase in operating expenditure above the levels incurred in the 2000-2005 regulatory period, noting that benchmarking evidence suggests that current expenditure levels appear low relative to other distributors.

The Commission acknowledges the impact of recently established requirements, such as FRC, on ETSA Utilities' forecast costs. The Commission has examined these proposed costs closely during this review process, and has allowed for increased expenditure to meet these new requirements.

While the benchmarks established represent the Commission's views on prudent and efficient operating costs, ETSA Utilities will remain responsible for managing the day-to-day operation of the prescribed business and it is able to increase or decrease expenditure in any areas where it believes it to be appropriate. The Commission does not consider it appropriate to determine the level of operational risk that ETSA Utilities must take.

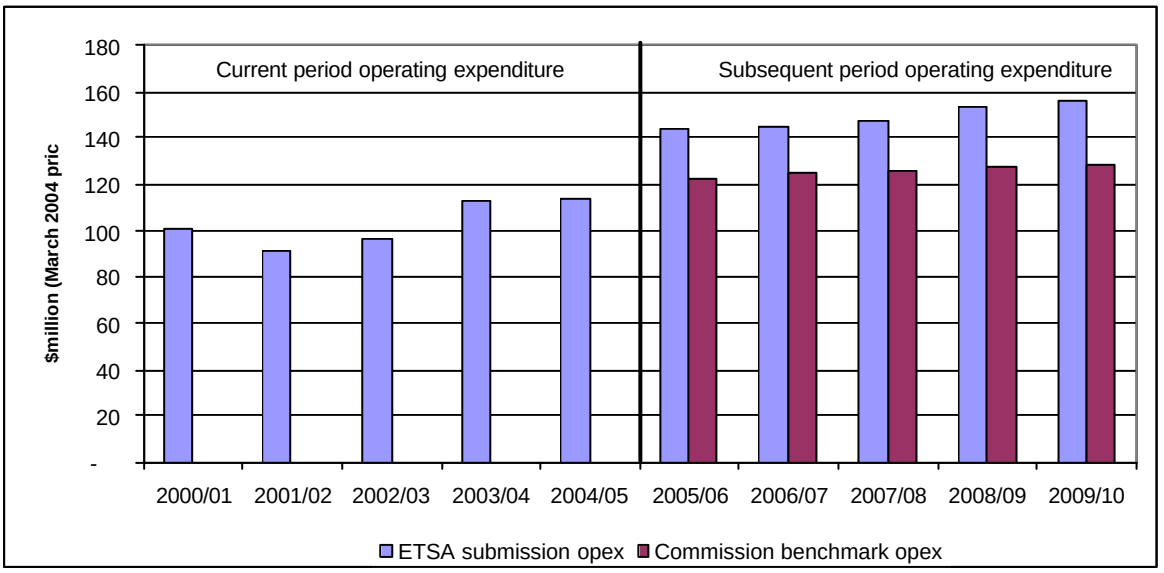
As set out in Table 8.17, the Commission has set a total operating expenditure benchmark of $629.6 million for the 2005-2010 regulatory period. This is approximately 22% greater than the operating expenditure that is forecast to be incurred by ETSA Utilities in the 2000-2005 regulatory period but is 16% lower than that proposed by ETSA Utilities.

Table 8.17: Operating Expenditure Benchmarks 2005/06 to 2009/10
($ millions in March 2004 prices)

OPERATING EXPENDITURE	2005/06	2006/07	2007/08	2008/09	2009/10	TOTAL
Commission benchmarks	122.7	125.0	125.5	127.8	128.5	629.6
ETSA Utilities proposal	144.1	145.2	147.7	153.3	155.8	746.1
Difference (%)	*-15*	*-14*	*-15*	*-17*	*-17*	*-16*

As Figure 8.2 illustrates, the Commission's decision represents a steady increase in operating expenditure from current levels, rather than supporting ETSA Utilities' proposal for a step increase.

Figure 8.2: Comparison of Operating Expenditure 2001/02 to 2009/10
($ millions in March 2004 prices)



9 REGULATORY ASSET BASE

9.1 Inputs to the Capital Related Costs

The key components that will be used to assess the capital-related costs are the regulatory asset base, depreciation and cost of capital[88]. The definitions of these components are as follows:

- *Regulatory asset base* – represents the regulator's view of the value of the existing investment in the regulated entity at any point in time. The objective when setting regulated charges can be described as designing price controls to provide an expected stream of revenue that has a present value equal to the regulatory asset base (on the assumption that all of the benchmarks – such as operations and maintenance costs – are correct)[89].
- *Regulatory depreciation* – represents the return of the capital that the distribution business has invested in the regulated distribution system over time.
- *Regulatory return* – is the annual rate of return (or profit) on the regulatory asset base that the price controls would be designed to deliver. In other words, the regulatory cost of capital is the rate that would be used to discount the income stream that is provided to the regulated entity. The objective of setting the price controls to reflect efficient cost implies that the return should reflect what investors would require to invest in the regulated activity, given investment opportunities elsewhere and the relative risk associated with that activity.

The concepts set out above are being used for a specific purpose – which is to guide the determination of regulated charges – and so the calculation of the inputs set out above needs to reflect this specific purpose. An objective imposed on the Commission is that the regulated charges must represent efficient investment.

The principle of efficient investment implies that the regulatory regime needs to ensure that investors expect to recover at least the capital they have invested (depreciation) and earn a fair commercial return on that capital (return on assets (ROA)).[90] An alternative way of expressing this is that the revenue benchmarks should be such that the present

88 While these terms are taken from the accounting field, their use is specifically directed towards setting price controls, which may differ from the objective of accounting (which is to provide a fair view of the state of the entity). Consequently, the definitions and principles underpinning these terms in the regulatory context may differ significantly from that in an accounting context.

89 It follows from this assumption that there are a number of reasons why the market value of the regulated assets may exceed the regulatory asset base, including that:

- the business outperforms against the benchmarks;
- the regulatory rate of return is above the cost of capital associated with the regulated activities; and/or
- the business is able to realise synergies with other businesses (and retains some or all of this benefit).

90 Under an incentive-based regulatory regime, actual returns may exceed or fall short of expected returns, depending upon the efficiency of the regulated entity.

value of revenue forecasted over the regulatory period is equal to the present value of the forecasted efficient cost of providing the regulated services.[91]

The nature of investment in electricity distribution (and other large infrastructure industries) has a number of features that distinguish it from those that may be undertaken in other markets:

- First, much of the investment is in assets that are expected to provide distribution services for many years, with the recovery of those costs spanning multiple regulatory periods;
- Second, much of the investment is in assets that are sunk, so that, once installed, they have little or no value in alternative uses;
- Third, these costs will account for the majority of ETSA Utilities' benchmark revenue requirement.[92]

The Commission has taken into account the particular characteristics of electricity distribution networks when considering how best to meet its relevant statutory obligations.

The concepts set out above are being used for a specific purpose – which is to guide the determination of regulated charges – and so the calculation of the inputs set out above needs to reflect this specific purpose. However, in considering how best to determine regulated charges, a number of regulators have drawn a parallel with a debate in the financial accounting field about the most appropriate definition of income, which has a direct bearing on the role – and hence calculation – of these inputs.

The debate from the financial accounting field referred to is the debate over two standards for the definition of income, which are as follows:

- Financial capital maintenance – in which income is defined as the surplus after a sufficient amount has been reserved to maintain the *financial value* of the business or asset; and
- Operating (physical) capability maintenance – in which income is defined as the surplus after a sufficient amount has been reserved to maintain the *physical capability* of the asset.

A key distinguishing feature of the two standards is the meaning of depreciation. Under financial capital maintenance, depreciation is the return of the original cost of the investment. In contrast, under operating capability maintenance, depreciation is a provision sufficient to fund the replacement of the existing assets when they expire. A further implication is how the initial investment is to be interpreted. Under the financial maintenance concept, the book value represents the remaining financial investment in the firm, and there is no necessary link to the physical assets of the firm. In contrast, under

91 In this present value calculation, the opening asset value is treated as a cost (net outflow) at the start of the period, and the closing capital base at the end of the regulatory period is the assumed residual value. The equivalence of the accrual expression for the revenue requirement and present value-type expressions are discussed further in chapter 6.

92 Typically, capital costs in a utility business make up about 60% to 70% of the total cost.

the physical capability maintenance concept, the book value represents the cost of replacing the existing assets in place (less the amount already set aside to replace the existing assets when they expire), and so there is a direct link between the book value and the specific assets in place.

The first of these standards – the financial capital maintenance concept – is more consistent with the objectives relevant to setting regulated charges, where the regulatory asset base of the business is taken as the value of the investment. That is, the relevant concern for encouraging investment is to protect the financial value of the *regulatory asset base* rather than protecting some measure of physical capability. Moreover, while it would be possible to use a methodology that mimics the physical capability standard when setting regulated charges, this would expose regulated utilities to technology risk and market risk – much of which is outside of their control – which would be likely to impose costs with little offsetting benefit. Lastly, the use of the physical capability concept would give rise to windfall gains in some circumstances.[93]

The regulatory approach for energy distribution in Australia is to set regulated charges using an accounting convention that mimics financial capital maintenance, which is reflected in the definitions of depreciation and the regulatory asset base set out above. The same concept has been applied in the determination of the prices in the current EPO.

A number of parallels for the setting of regulated charges can be drawn from the accounting concept of financial capital maintenance. One important parallel comes from the observation that the value of the investment is independent of the individual physical assets – for regulation, this implies that the *aggregate* value of the regulatory asset base and the *aggregate* level of regulatory depreciation are the relevant parameters, rather than amounts attributed to individual assets. A second important parallel follows directly from the role of depreciation – regulatory depreciation is the return of the value of the *regulatory asset base*, and is not related to the replacement expenditure that the entity may need to undertake.

Finally, and most importantly, the Commission notes that its adoption of a financial capital maintenance standard is not inconsistent with the legislative framework within which it operates, which continues to provide the guidance for the Commission's price determination. It is also noted that the legislative framework may in fact dictate that the financial maintenance concept be departed from at times – by way of example, its approach to creating incentives for efficiency gains is achieved by de-linking revenue and cost for a period, which implies a reduction in emphasis on financial maintenance.

[93] A windfall gain would arise wherever the starting value of the regulated asset was lower than its depreciated replacement cost. An example of this is where assets have been contributed by customers. Under physical capability maintenance, the regulated entity would receive depreciation immediately in respect of assets it did not fund so that it could replace the assets at the end of their lives. In contrast under financial capital maintenance, the regulated entity would only receive a return on funds it has actually invested – which would include the replacement of user-contributed assets, once that replacement investment had been made.

9.2 Establishing the Opening Regulatory Asset Base

Many of the issues associated with updating the regulatory value of ETSA Utilities' fixed asset base for the commencement of the next regulatory period are prescribed in the EPO[94]. The Asset Schedule in the EPO prescribes the value for those assets as at 1 July 1999, as set out in Table 9.1.

Table 9.1: ETSA Utilities' Asset Base as at 1 July 1999

	SKM REPORT VALUES[1]	ADDITIONS	BALANCE	CPI ADJUSTMENT[3]	DEPRECIATION	BALANCE
	01-JUL-98 $'000	**98/99 $'000**	**30-JUN-99 $'000**	**$'000**	**98/99 $'000**	**01-JUL-99 $'000**
LINES	1,265,000	29,600	1,294,600	1,310,598	46,400	1,264,198
METERS / SERVICES	141,000	35,700	176,700	178,686	10,700	167,986
TRANSFORMERS	391,000		391,000	395,888	14,000	381,888
SUBSTATIONS[2]	254,000	10,600	264,600	267,841	12,900	254,941
COMMUNICATIONS	13,000	- -	13,000	13,163	1,700	11,463
TOTAL	2,064,000	75,900	2,139,900	2,166,176	85,700	2,080,476

1. Assets not valued by SKM, eg land and buildings, have not been included in this table although they have been included in the rate base.
2. Capital expenditure not split between substations and transformers, allocated all to substations.
3. Increased by 1.25% CPI estimate for 98/99. To reflect the timing of additions throughout the year, only 50% of additions have been increased by the CPI adjustment.

Clause 7.3(b)(i) then requires the Commission to adjust the value of the assets, using the following methodology:

DETERMINING THE OPENING REGULATORY ASSET BASE
Opening Fixed Asset Base (Jul.1999)
plus
Capital Expenditure (Jul.1999-Jun.2005)
less
Disposals (Jul.1999-Jun.2005) and Contributions (Jul.1999-Jun.2005)
less
Regulatory Depreciation (Jul.1999-Jun.2005)

In addition, as tariffs were designed to deliver a real (rather than nominal) return on assets, an adjustment needs to be made to compensate investors for changes in the general price level (inflation) over the first regulatory period.

94 The EPO specifies the methodology for determining the value of the fixed assets where the value of those assets is 'required to be taken into account'. The Commission's methodology for setting the benchmark revenue requirement requires that the value of these assets be taken into account.

The following discussion outlines the issues associated with adjusting the initial asset base for inflation, capital expenditure, disposals and contributions during the first regulatory period. Regulatory depreciation is also considered in section 9.2.4.

9.2.1 Treatment of Inflation

There are two methodological issues of inflation adjustment. These relate to:

- a method for addressing inflation that is forecast to occur over the next regulatory period (ie future inflation); and
- a method to be used to update historical values for actual inflation (ie past inflation).

These two issues are outlined below.

Use of Constant Price (Real) Dollars for the Next Regulatory Period

Where regulated charges are set to deliver a real return that is escalated for inflation, the most straightforward approach is to set all financial inputs in constant price terms[95], and then to apply the relevant escalation for inflation as a last step. For the purposes of the price determination, all financial forecasts will be expressed in March 2004 prices.

For the purpose of finally inflating the dollars figures, an assumption must be made on when the cost is incurred, and the revenue generated. It is therefore proposed that the Commission will adopt the common assumption that any revenue or expenditure is received or incurred at the mid-point of the regulatory year (i.e. end of December).

Updating Historical Values for Actual Inflation

The purpose of indexing the regulatory asset base (and all of its components) for actual inflation is to compensate investors as closely as possible for movements in inflation (purchasing power). The effect of this is to protect investors from inflation risk over the long-term.

Given this objective, it is appropriate to adopt the measure of actual inflation that is relevant for changes to the purchasing power of money in the Australian market, which is commonly taken to be the All Groups Consumer Price Index – Average of the Eight State Capitals, as published by the Australian Bureau of Statistics. This measure of inflation is currently used in the EPO for escalating tariffs.

The determination of the appropriate level of escalation for historical inflation also requires an assumption about the timing of revenue and expenditure within each

95 'Constant price terms' implies that values are expressed in terms of an equivalent level of purchasing power, that is, removing the effects of inflation.

year. Consistent with the proposed treatment of inflation in the future, the Commission will adopt the assumption that all revenue and expenditure occurs in the middle of the year.

When escalating historical expenditures for actual inflation, the Commission proposes to mirror the treatment of inflation in ETSA Utilities' current price controls and use the CPI from 9 months prior to a point in time as the proxy for the price level at that point in time. The following example illustrates the use of the 9-month lagged CPI in the EPO:

- To escalate 2002/03 prices (assumed to be charged in the middle of the year, ie December 2002) into 2003/04 prices (assumed to be charged in December 2003), the EPO requires inflation to be calculated as the ratio of the March 2003 and March 2002 CPI observations.
- Accordingly, the escalation of tariffs under the EPO implicitly uses the March 2002 CPI as a proxy for the price level in December 2002 and the March 2003 CPI as a proxy for the price level in December 2003[96].

It is noted that while the use of a lagged measure of CPI may provide a biased measure of inflation over any year, the continued use of a CPI lagged by nine months will minimise any errors in the adjustment for inflation over time.

Accordingly, the Commission has decided that:

- all financial forecasts should be expressed in constant prices, with a base date of March 2004;
- revenue and expenditure should be assumed to be received or incurred at the midpoint of each year (ie 31 December) for past and future revenue and expenditure;
- the All Groups Consumer Price Index – Average of the Eight State Capitals, as published by the Australian Bureau of Statistics should be used as the measure of actual inflation; and
- the CPI from 9 months prior to a point in time should be used as the proxy for the price level at that point in time, mirroring the treatment in the current price controls.

9.2.2 Treatment of the GST-related 'spike' in inflation

While the historical GST-related component of inflation is no longer relevant to the extent of inflation that is factored directly into regulated charges, an issue for the price determination is whether that component of inflation should also be precluded from flowing through into the updated regulatory asset values – and hence indirectly into future regulated charges.

96 The rationale for using the measure of inflation over the year to March when escalating financial-year tariffs is that the year to March will be the latest information on inflation available prior to approving the tariffs for the year ahead.

Further, if it is considered that permitting the GST component of inflation to flow through directly into current prices would permit windfall gains, then the same logic would imply that windfall gains would be generated if that component of inflation were permitted to flow through into a regulatory asset value. Thus, consistency with the treatment of regulated charges over the period would imply updating ETSA Utilities' regulatory asset value by the 'headline' measure of inflation over the regulatory period, minus the estimated impact of the GST 'spike'.

There are four key issues of substance, in considering the treatment of GST induced spike in the CPI:

- whether precluding the spike from flowing through into the regulatory asset base would cause a windfall loss to investors;
- the relevance of consistency with the effect of other government measures on inflation;
- the status of the regulatory precedents; and
- whether the legislative framework may rule out such an adjustment.

Regarding the first of these issues, ETSA Utilities has argued that failing to permit the spike to be reflected in the regulatory asset base would lead to the real value of the regulatory asset base in the eyes of investors falling, and hence a loss. However, while the Commission accepts that ETSA Utilities' argument may be correct if attention is drawn only to investor returns in before-tax terms, the Commission considers that the argument made in the submission by the South Australian Centre of Economic Studies (SACES) has considerable merit. In particular, it is noted that the GST was introduced as part of a package of measures, a component of which was the reduction in personal income taxation. The latter measure was designed to more than offset the effect of the GST on the purchasing power of a given stream of pre-tax income.

In this respect, it is relevant to consider the impact of the GST on wages – the returns to labour. Prior to the introduction of the GST, it was assumed that the purchasing power impacts of the GST would be more than offset through changes in personal income taxation, with the implication that there would be no need to inflate nominal wages in response to the GST effects on inflation. This objective was realised and nominal wages increased by an amount that did not include the impact of the GST on inflation. It is not clear why such a principle should not hold also to investor income.[97]

Accordingly, while the Commission considers that the analysis of the full effect of the introduction of the GST on investor returns is complex, it is not convinced that ETSA Utilities' contention that a failure to pass through the GST-related spike in

[97] Treasury Working Paper, Preliminary Analysis of the Impact of The New Tax System.

inflation into its regulatory asset base will necessarily create a loss (and hence failure to preserve financial capital).

That said, the Commission accepts that the weight of regulatory precedent would appear to support ETSA Utilities' contention that measured inflation not be adjusted for the GST spike. In particular, while the ACCC appears to have adopted different positions for electricity and gas (adjusting for the spike in electricity, but rejecting such an adjustment for gas), the other regulators that have considered the issue explicitly (the Victorian ESC and IPART) have rejected an adjustment to measured inflation. As required under various legislative instruments, in making its decision, the Commission has had regard to regulatory precedents.

Lastly, regardless of the merits of the above arguments, the Commission recognises that there is a legal impediment to making any adjustment to inflation. Clause 7.2(e)(i) of the EPO requires that an adjustment for inflation, amongst other things, be made to the opening regulatory asset base. The Commission has received legal advice that this clause precludes the Commission from making adjustments to inflation figures.

As compliance with legislative obligation is the Commission's primary concern, the Commission has decided not to adjust measured inflation to remove the effects of the GST induced spike in inflation, noting in particular that the EPO prevents such an adjustment, notwithstanding the merits. The Commission has also placed weight on regulatory precedent in reaching this conclusion.

9.2.3 Capital Expenditure During the First Regulatory Period

The first component of the building block involves forming a view on efficient capital expenditure. Clause 7.2(e)(i) and 7.3(b)(l) of the EPO indicate that the Commission does not have discretion to conduct a 'prudence' test on capital expenditure over the first regulatory period. Accordingly, actual expenditure needs to be rolled in to the regulatory asset base. However, as this restriction does not preclude the use of prudence tests in future price reviews, the question arises as to whether a test of the efficiency of capital expenditure would be desirable in the future.

The rationale or importance of a prudence test will depend upon the efficiency of the incentives for ETSA Utilities that are created by the regulatory arrangements. The incentive arrangements applicable to ETSA Utilities aim to encourage cost minimisation in the provision of the regulated services. Under price caps, any reduction in capital expenditure provides immediate benefits to the business (as it is able to earn a return on funds that have not been spent).

The potential for some of the benefit from underspending to be retained for the next regulatory period, under the efficiency carryover mechanism (see Chapter 6),

further enhances this incentive to reduce costs.[98] The existence of these incentives lends support to at least a prima facie presumption, that the capital expenditure undertaken during the period will be 'efficient' (ie will not be more than necessary).

Due to the requirements of the EPO, supported by the existence of an efficiency incentive scheme, the Commission has decided that all of ETSA Utilities' actual capital expenditure for the first regulatory period is to be rolled into the regulatory asset base.

9.2.4 Regulatory Depreciation and Disposals in the First Regulatory Period

There are two options open to the Commission when adjusting ETSA Utilities' regulatory asset base for regulatory depreciation over the first regulatory period. These are:

- To recalculate the regulatory depreciation that would be consistent with the actual level and mix of capital expenditure that was undertaken over the period; or
- To deduct the value of regulatory depreciation reflected in the revenue benchmarks that underpinned ETSA Utilities' current price controls (adjusted for inflation).

Similarly, with respect to disposals, two options exist. These are :

- To adjust the regulatory asset base to remove the regulatory book value of assets disposed; or
- To remove from the regulatory asset base the proceeds obtained by the disposal of the assets.

The key difference between the two options is that the first adjusts for depreciation and disposals on the basis of *(regulatory) book values*, whereas the second adjusts according to *movements in cash*.

The second option for both depreciation and disposals is consistent with the view that depreciation and disposals should be interpreted as the return of invested capital. That is, the second options target directly the return of invested capital received over the previous period, and is more consistent with the financial capital maintenance concept adopted by the Commission.

Despite this, the Commission acknowledges the clear preference by both ETSA Utilities and the consumer groups[99] to use the recalculate the regulatory depreciation based on actual capital expenditure. The Commission accepts that the existing regime may not provide ETSA Utilities with sufficient incentive to

[98] Consumers benefit from the use of incentive regulation over the medium term as these savings are passed through to lower prices.

[99] Submission provided by South Australian Centre of Economic Studies (SACES) on behalf of the consumer group.

maximise the proceeds of disposals. The Commission also notes that preserving the link between the calculation of depreciation for individual assets and the overall regulatory asset base may help, in particular, to preserve the flexibility for alternative regulatory approaches in future regulatory periods.

Having considered the various factors, the Commission has decided that it will recalculate the depreciation based on actual capital expenditure spent during the 2000-2005 regulatory period (although it is a deviation away from the financial maintenance concept) and the actual disposal values obtained.

To satisfy itself of the potential scope for ETSA Utilities to exercise strategic behaviour under the first option, the Commission has reviewed the depreciation model provided by ETSA Utilities and is satisfied that the model is an accurate reflection of the assumptions in the current EPO.

9.2.5 Customer Contributions

Clause 7.2(e)(iii) of the EPO precludes the Commission from incorporating into the fixed asset base the value of any network augmentations or extensions that were funded directly by customer contributions. The rationale for this is that there is no justification for providing ETSA Utilities with a return on investment that it has not funded. Accordingly, these customer contributions will be netted off capital expenditure.

9.2.6 Non Fixed Assets

As stated earlier, the *Asset Schedule* (Schedule 9) in the EPO prescribes the initial value of the regulatory asset base that must be used for price resetting. However, the Asset Schedule relates only to the valuation of what the EPO refers to as ETSA Utilities' fixed asset base.

Clause 7.2(e)(iv) of the EPO also requires consideration of other assets that are not listed in the *Asset Schedule* but are nevertheless required in order for ETSA Utilities to provide distribution services. The following non-fixed assets are not included in the *Asset Schedule* but were included in the asset base that was used to set the current price controls:

- Land and buildings;
- Plant and tools;
- Easements;
- IT assets; and
- Office equipment.

In addition to the above list of non-fixed assets, there are two further items of capital requirement that are included for the purpose of calculating the regulatory return on investment. These are:

- Capital work in progress (that is assets that have not yet been commissioned); and
- Working capital.

This section deals with the non-fixed assets. Capital work in progress and working capital issues are discussed under sections 9.2.7 and 9.4 respectively.

Even though a value for non-fixed assets was not prescribed in the *Asset Schedule*, both a return on and return of (ie depreciation) the value of these assets was reflected in the EPO's current price controls. The calculation of this 'return on and of' the value of non-fixed assets was based upon an assumed starting regulatory value for these assets, and a roll-forward of that value to reflect forecasts of capital expenditure, depreciation, disposals and inflation. That is, the treatment of non-fixed assets in the derivation of the current price caps was identical to the treatment of fixed assets.

The values for non-fixed assets that were used are reproduced in Table 9.2.

Table 9.2: Value of non-fixed assets as at 1 July 1999

ASSET CLASS	$ MILLION
Land and buildings	58
Plant and tools	23
Easements	6
IT assets	19
Office equipment	3
Working Capital	80
Capital works in progress	32
Total non-fixed assets	221

Source: ETSA Utilities' Information Memorandum, Volume 1

Issues Raised by ETSA Utilities

During the consultation process on these issues[100], ETSA Utilities argued that the value of easements and land should not be based on the current value since the regulatory values assigned to the easements were not subject to any form of 'valuation verification', and that "*the disposal process for the distribution network represents a basis upon which real values for substation land and easements can now be introduced in to the regulatory asset base*".[101]

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[100] The Commission has previously released two Papers on "Return on Assets"; Discussion Paper, August 2003 (http://www.escosa.sa.gov.au/resources/documents/030818-R-ElectReturnOnAssets_DiscPaper.pdf), and "Preliminary Views" January 2004 (http://www.escosa.sa.gov.au/resources/documents/040114-R-EDPR-ReturnOnAssets-PrelimViews-Final.pdf).

[101] ETSA Utilities – Submission in response to the Commission's Discussion Paper, September 2003 (refer http://www.escosa.sa.gov.au/resources/documents/030929-R-ETSA_Submission-ETSA.pdf). ETSA Utilities accepted that the valuation for other no-fixed assets should be based on the original valuation included in the current regulatory asset base.

In response to the "Preliminary Views" paper[102], ETSA Utilities submitted that at the time of the issue of the EPO (October 1999), a reasonable assumption by a potential purchaser of the distribution network in SA would be that the Regulator would value land and easements on a deprival value basis.

In drawing this conclusion, ETSA Utilities relies on clause 6.10.3(e)(5)(iii) of the National Electricity Code (NEC), clause 7.2(e)(iv) of the EPO and a submission made by the Electricity Reform and Sale Unit (ERSU) to the ACCC, on the EPO.

The argument put forward by ETSA Utilities is discussed below.

Clause 7.2(e)(iv) of the EPO states that:

> *consideration should also be given to assets that are not included in the Asset Schedule but are necessary to enable ETSA Utilities to provide prescribed distribution services in accordance with good electricity industry practice and the requirements of the Code, the Distribution Code and any other applicable laws including, without limitation, the easements used by ETSA Utilities to provide prescribed distribution services.*

This clause requires the Commission to ensure that a value for easements, amongst other things, must be included in the regulatory asset base.

ETSA Utilities further argues that the current regulatory base incorporates a value for easements and land that was based upon "*an incomplete process*". To make this argument, ETSA Utilities relies on a submission made by ERSU to the ACCC, when it sought the ACCC's approval for the EPO. The submission stated that:

> *"In addition to the assets valued by SKM, an allowance for working capital costs and other items not valued by SKM such as land and buildings, plant and tools, IT assets and Office equipment has been added to the regulatory asset base.*
>
> *…easements have been included in the initial asset base at book value, since asset valuation consistent with the approach set out in the Draft Statement of Regulatory Principles have not yet been undertaken."*

ETSA Utilities claim that the import of this submission is that:

> *"the incontrovertible evidence is that, at the time of the EPO, the then jurisdictional regulator did not value those sunk assets constituted by the easements and substations land."*[103]

Given this, ETSA Utilities refers to clause 6.10.3 (e)(5)(ii) & (iii) of the NEC, which states that:

> *(ii) subject to clause 6.10.3 (e)(5)(i), assets (also known as "sunk assets") in existence and generally in service on 1 July 1999 are valued at a value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the participating jurisdiction;*

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[102] The Commission has not released a Working Conclusions Paper on the issue, and hence comments received in response to the "Preliminary Views" paper are addressed in this Paper.

[103] ETSA Utilities, Submission in response to the Commission's Preliminary Views – February 2003, pp26

(iii) subject to clause 6.10.3 (e)(5)(i), valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the Jurisdictional Regulator. In determining the basis of asset valuation to be used, the Jurisdictional Regulator must have regard to:

A the agreement of the Council of Australian Governments of 19 August 1994, that deprival value *should be the preferred approach to valuing network assets;*

B any subsequent relevant decisions of the Council of Australian Governments; and

C such other matters reasonably required to ensure consistency with the objectives specified in clause 6.10.2;

Based on these requirements of the NEC, ETSA Utilities concluded that:

"The two relevant considerations arising from the clause 6.10.3(e)(5) of the NEC are that:

- *if the original intention had been implemented (i.e. if there had been no omissions from the SKM valuation) then these other sunk assets, including easements and substation land, would have been valued on the same basis as those assets which were included in the fixed asset base (i.e. on a deprival basis); and*
- *where there is a subsequent revaluation of sunk assets then that revaluation must be undertaken having regard to the COAG agreement of 19 August 1994 that deprival value should be the preferred approach to valuing network assets."*

ETSA Utilities further stated that:

"It is ETSA Utilities' submission that the relevant statutory directions compel ESCOSA to approach the valuation of the easements in the manner dictated by the NEC, i.e. deprival value."

Finally, ETSA Utilities concluded that based on the above arguments, the Commission must revalue the easements and land. The appropriate valuation for these non-fixed assets, as stated by ETSA Utilities, is the amount that was paid for the Distribution Network Land Lease (DNLL). This amount was $276.2m, which represented the present value of all monthly rent instalments owing under the DNLL to the Distribution Lessor Company the lessor under the land lease.

ETSA Utilities have stated that

"…ETSA Utilities will accept, for the purposes only of a decision under Part 3 of the ESCA, a value for the easements and substation land very substantially less than the deprival value, namely the actual cost to ETSA Utilities of acquiring the easements and substation land in 1999, $276.2 million."

The Commission's assessment on Easement and Land

The Commission agrees with the position put by ETSA Utilities only insofar as it agrees that clause 7.2(e)(iv) of the EPO requires the Commission to consider the value of assets not included in the *Assets Schedule*, including easements, when taking into account the value of the assets used by ETSA Utilities. The Commission does not agree that there is anything in that clause of the EPO or in

the NEC which would require it to re-value easements and land for the purposes of the price determination.

Contrary to the submissions of ETSA Utilities, it is clear that easements and land have been valued for the purposes of establishing ETSA Utilities' initial regulatory asset base. This is so notwithstanding the fact that the valuation methodology adopted by the South Australian government at the relevant time did not accord with the Draft Statement of Regulatory Principles.[104] The Commission does not accept that the value included within the initial regulatory asset base was an outcome of an "incomplete process" for valuing easements and land. Such a statement implies that the value only relates to a portion of the total amount of easements and land, whereas it is necessarily the case that the value must represent a complete value, albeit one calculated under a different methodology to that promoted by ETSA Utilities.

As discussed in Chapter 1, the Commission's primary guidance in making this price determination is the requirements of the NEC, as moderated by the imperatives of the EPO. ETSA Utilities has, appropriately, pointed to the provisions of clause 6.10.3 of the NEC as setting out the principles with which the Commission must comply in relation to the valuation of easements and land. The relevant clauses identified by ETSA Utilities are 6.10.3(e)(5)(ii) and (iii). For the purposes of explaining the Commission's reasons, it is useful to consider the whole of clause 6.10.3(e)(5):

(e) The regulatory regime to be administered by the Jurisdictional Regulator must be consistent with the objectives outlined in clause 6.10.2 and must also have regard to the need to:

(5) provide a fair and reasonable risk-adjusted cash flow rate of return to Distribution Network Owners on efficient investment given efficient operating and maintenance practices on the part of the Distribution Network Owners where:

(i) assets created at any time under a take or pay contract are valued in a manner consistent with the provisions of that contract;

(ii) subject to clause 6.10.3 (e)(5)(i), assets (also known as "sunk assets") in existence and generally in service on 1 July 1999 are valued at a value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the participating jurisdiction;

(iii) subject to clause 6.10.3 (e)(5)(i), valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the Jurisdictional Regulator. In determining the basis of asset valuation to be used, the Jurisdictional Regulator must have regard to:

[104] The Commission notes that as at the time of writing this draft determination, those Principles remain in draft form. The Commission also notes that the Draft Statement of Regulatory Principles is not binding on the Commission in the performance of its functions under the NEC.

A *the agreement of the Council of Australian Governments of 19 August 1994, that* deprival value *should be the preferred approach to valuing* network *assets;*

B *any subsequent relevant decisions of the Council of Australian Governments; and*

C *such other matters reasonably required to ensure consistency with the objectives specified in clause 6.10.2.*

The Commission has analysed the requirements of this clause, and has concluded that there is nothing in it which directs or requires the Commission to undertake any revaluation of easements and land. The Commission notes at the outset that it is clear that clause 6.10.3(e)(5)(i) can be disregarded for the purposes of easements and land.

Turning to clause 6.10.3(e)(5)(ii), that clause has application in respect of easements and land which existed and were generally in service as at 1 July 1999. The clause requires that where the Commission is considering those assets (the "sunk assets"), the value which is to be ascribed to those "sunk assets" is either a value determined by the Jurisdictional Regulator or a value which is consistent with the regulatory asset base established in South Australia.

The clause does not itself provide any guidance as to which value is to be preferred; instead, the preference is to be ascertained from a consideration of the objectives set out in clause 6.10.2 and the other principles of clause 6.10.3.

The Commission therefore has formed the view that in making a decision as to the value which is to be given to the "sunk assets", it must consider clauses 6.10.2 and 6.10.3 in order to first determine whether it must itself determine a value (as preferred by ETSA Utilities) or it is entitled to utilise a value which is consistent with the regulatory asset base established in South Australia.

For example, clause 6.10.2 (g) requires that the jurisdictional regulator must give:

> *"reasonable recognition of pre-existing policies of governments which are Distribution Network Owners regarding distribution asset values, revenue paths and prices."*

When the current regulatory asset values were derived, the government was the owner of ETSA Utilities. Although the ownership has since changed, the EPO has remained unchanged during this transition. Hence, as the code requires, recognition of the original value for easements must be given in deciding the regulatory asset base.

Moreover, the principles outlined under 6.10.3 of the NEC provide more clarity on the issue. In particular, clause 6.10.3(iv)(A) requires the Commission to have regard to:

> *"relevant previous regulatory decisions made by authorised persons including the initial revenue setting and asset valuation decisions made by a government at a time at which that government*

was a Distribution Network Owner in the context of industry reform pursuant to the Competition Principles Agreement."

On this basis, the Commission considers that the requirements of the NEC in respect of "sunk assets" are such that the Commission may ascribe a value to easements and land in existence and in service as at 1 July 1999 in a manner consistent with the regulatory asset base established in South Australia. As set out in Table 9.2, these values are approximately $6 million and $58 million respectively.

Clause 6.10.3(e)(5)(iii) is somewhat different in operation to clause 6.10.3(e)(5)(ii), insofar as it specifies that Jurisdictional Regulators must, when valuing assets brought into service after 1 July 1999 (the "new assets"), or subsequently revaluing either those "new assets" or the "sunk assets" described above, have express regard to the three factors set out at A, B and C of the clause.

The Commission understands this to mean that where the clause has application, the three listed factors are to influence the Commission's decision as to the valuation methodology which it should adopt. However, the Commission also notes that there is nothing in clause 6.10.3(e)(5)(iii) which requires the Commission to revalue "sunk assets": the clause simply provides that where the Commission is undertaking such an exercise, it must do so having regard to the three enumerated factors of A, B and C.

The Commission has already noted its view that the appropriate value to ascribe to easements and land in existence at 1 July 1999 is one consistent with the regulatory asset base established in South Australia. In relation to those easements and any land acquired by ETSA Utilities after that date, the Commission considers that 6.10.3(e)(5)(iii) requires it to ascribe a value to those assets having regard to:

A *the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;*

B *any subsequent relevant decisions of the Council of Australian Governments; and*

C *such other matters reasonably required to ensure consistency with the objectives specified in clause 6.10.2.*

Having regard to these matters, the Commission is of the view that the purchase price paid for easements and land purchased by ETSA Utilities after 1 July 1999 (and as adjusted pursuant to clause 7.2(e)(i) of the EPO) is the appropriate value at which those "new assets" are to be included within the regulated asset base.

Having set out the Commission's approach to ascribing values to easement and land "sunk assets" and "new assets", it is not strictly necessary to consider ETSA Utilities' contention that the amount it paid the South Australian government under

the DNLL is the appropriate value to be included within the regulated asset base for easements and land. Nevertheless, the Commission considers that it should set out its views in relation to that contention, and why it does not agree with ETSA Utilities.

The Commission's understanding of the structure of the overall sale/lease arrangements entered into between the South Australian government and the ETSA Utilities partnership is that while there were separate leases for the distribution network and the distribution network land, the government did not require any particular structure to be adopted by bidders for the overall business.

The government has advised the Commission that bidders were required to submit their overall bids utilising whichever rental payment structure they wished, provided that the structure was consistent with the government's objectives and risk position. In other words, the winning bidder (the partnership which now operates ETSA Utilities) effectively determined the rental amount it would pay for each component of the entire business (ie, the distribution network and the distribution network land), based on its business decision as to its bid structure.

As a result, the amount which was paid under the DNLL is not necessarily linked to the value of the easements and land *per se*, but is instead more strongly associated with the bid structure devised. It would just as readily have been open to the ETSA Utilities partnership to have made a bid utilising a different structure: with the necessary implication that the value it might have paid under that structure would no more represent an appropriate value to ascribe to all easements and land than does the rental payment actually made.

Other Relevant Matters – Regulatory Consistency

A further relevant matter for consideration is how other regulators have addressed the issue of valuation of easements for regulatory purpose. As discussed above, regulators' decisions on this matter prior to the sale of ETSA Utilities is relevant to the reasonableness of expectations at the time of the sale (and, in turn, possibly to provide incentives for efficient investment), and all decisions are directly relevant for the purposes of section 6(1)(b)(vii) of the ESC Act and clause 7.2(k)(ii) of the EPO.

In relation to electricity transmission, the ACCC released its draft Statement of Principles for the Regulation of Transmission Revenues in May 1999. The ACCC sought public submissions on the draft and foreshadowed releasing a final version of the Principles later in that year.[105] However, as it has transpired, no final version was ever issued. The methodology the ACCC proposed for valuing easements in its draft Principles was to value these assets at the cost of acquiring the assets, and to update these values over time in line with the current cost of

[105] ACCC, 1999, Draft Statement of Regulatory Principles, May, pp.xix-xx.

acquiring easements. The ACCC noted that, as real estate values tend to rise faster than the CPI, it would avoid the potential for windfall capital gains by setting a negative depreciation charge (ie reducing regulated revenue by an amount equal to the capital gain).

While not stated explicitly, the ACCC appeared to imply that existing easements for electricity transmission assets would be valued at their current cost of acquisition.

However, in all of the matters the ACCC has addressed, it has found that to revalue all existing easements for transmission entities would imply a substantial upward revaluation of the entity's regulatory asset base – and hence imply higher prices to consumers – and as a consequence has never re-valued easements using such a methodology. Indeed, in its first decision, it appeared to envisage easements transitioning to a value equivalent with current replacement cost – but only after imposing a 'negative depreciation' adjustment to prevent a windfall gain from being received:[106]

> *The ACCC is currently reviewing the submissions made in response to this and other elements of its proposed Regulatory Principles before finalising its longer-term approach.*
>
> *Accordingly, for the purpose of the present decision, and bearing in mind the need of the networks to be allowed to earn an adequate return on their investments and the desirability that customers should not be required to face an immediate price shock, the ACCC considers it appropriate to include TransGrid's existing easements in the regulated asset base at their historic purchase cost rolled-forward to 1 July 1999. In the absence of properly documented historic cost records, the ACCC has used the values identified in the oldest available valuation as a proxy for those costs, being the DORC value determined during the 1996 SKM valuation.*
>
> *During the Regulatory Principles process, the ACCC will give further consideration to the merits of allowing TransGrid to transition to a properly established DORC/ODV valuation approach (including an assessment of whether using undergrounded cables instead would be more efficient) over a time frame which enables it to balance its business cash needs with the 'negative depreciation' charges which those assets are likely to generate. Such an approach would also have the advantage that it would ensure that network customers would not face price shocks as a result.*

The method by which easements have been valued in the ACCC's final decisions to date are set out in Table 9.3.

[106] ACCC, 2000, NSW and ACT Transmission Network Revenue Caps 1999/00 – 2003/04: Final Decision, January, pp.61-62.

Table 9.3: ACCC Decisions on Easement Valuations

COMPANY	DATE OF FINAL DECISION	METHODOLOGY	EASEMENT VALUE
TransGrid (NSW)	January 2000	Preferred historical purchase cost but, in the absence of information, used the oldest available valuation as a proxy (a 1996 DORC valuation).	$312 million
Powerlink (Qld)	November 2001	Historical acquisition cost, escalated using a proxy for a property price index.	$114.3 million
SPI PowerNet (Vic)		Historical acquisition cost (compensation payments only), escalated using the CPI.	$88.9 million
ElectraNet (SA)	December 2002	Book value.	$3.1 million

ACCC, 2000, NSW and ACT Transmission Network Revenue Caps 1999/00 – 2003/04: Final Decision, January, pp.61-62; ACCC, 2001, Queensland Transmission Network Revenue Cap 2002 – 2006/07: Final Decision, November, p.33; ACCC, 2002, Victorian Transmission Revenue Caps 2003-2008, December, p.54; ACCC, 2002, South Australian Transmission Network Revenue Cap 2003 – 2007/08, December, pp.44-45.

Indeed, in its Draft Statement of Principles for the Regulation of Transmission Revenue, the ACCC discussed at some length what it considers are the unique features of easements, and has expressed its preferred position as to adopt a historical cost valuation of easements.[107]

Of possibly more relevance to the issue of ETSA Utilities, is how easements have been valued for the purpose of setting regulated charges for other electricity distributors. For distributors, regulatory or government decisions to date have been reasonably consistent – in particular, easements have either not been ascribed any value, or only a nominal value (consistent with a book value for the asset).

In particular, it is understood that the Victorian Government did not include a value in respect of easements in the opening regulatory asset bases that were prescribed for the five Victorian distributors in 1995.[108] IPART specifically considered the issue of easement valuation in its 1999 report to the NSW Premier on the price controls for the NSW electricity distributors, and commented on the valuation issues as follows:[109]

> *However, the Tribunal recognises that the easements are required by the DNSP to provide electricity services. Electricity easements are generally granted in perpetuity. Gradual growth in load, and the difficulty and expense of negotiating a new easement means that they are almost never replaced. Indeed, a network is far more likely to seek to alter the terms of an existing easement to allow a different sized wire to be erected rather than to extinguish the easement and*

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[107] ACCC, 2003, Discussion Paper – 2003 Review of the Draft Statement of Principles for the Regulation of Transmission Revenues, pp.30-33. The ACCC's preferred position on easement valuation is subject to the rider that its preferred position is not to revalue any assets, but rather to roll-forward the current regulatory asset base at future reviews, which would lock in the easement values described above (albeit updated in line with new acquisitions at cost, and inflation).

[108] These regulatory asset bases are set out in: Victorian Electricity Supply Industry Tariff Order, June 1995, Order in Council under Section 158A of the Electricity Industry Act 1993, clause 5.10. The Victorian Government also chose not to include a value for easements when setting the opening regulatory asset base for the transmission entity: ACCC, 2002, Victorian Transmission Revenue Caps 2003-2008, December, p.48.

[109] IPART, 1999, Pricing for Electricity Networks and Retail Supply, Vol 1, June, p.60.

negotiate a new one. The restrictive nature of easements (eg, being an easement only for electricity distribution lines) may mean that they do not have value to any other entity.

The Tribunal considers that including a market value for existing easements in the initial asset base is of no economic benefit. In addition, price shocks of this magnitude are unacceptable. Should new easements have to be acquired the expenditure will be considered on the same basis as the other elements of capital expenditure.

IPART's report considered valuations of easements in line with current replacement cost, but rejected those valuations in favour of valuing existing easements at historical cost. As IPART was required to base its report on the application of the NEC, it was required to take account of (but was not bound by) the pre-existing government policies with respect to asset valuation. The NSW Government informed IPART that its policy with respect to easements was as follows:

I wish to confirm that in terms of this section of the code the "pre-existing policies" of the government are reflected in the most recent asset valuations provided by Treasury which include:

1. *Independently determined ODRC valuations of the physical assets of the NSW distributors (incorporating revisions to Treasury guidelines as recommended by the independent consultants); and*
2. *Replacement cost valuations of easements prepared by independent consultants.*

Adoption of these values including the replacement cost of easements would result in a very significant increase in asset values in the two largest distributors. Given the current uncertainty in relation to the regulatory treatment of easements, I would therefore propose that for this review the ODRC values for distributors should include easements at actual costs, rather than replacement value. Furthermore, the asset values for rural distributors may need to be constrained so as to avoid real increases in network charges.

IPART has recently expressed its preference for updating the regulatory asset bases it set in 1999 over time using the roll-forward method. IPART has noted that the application of this method would imply that the easements in place in 1999 would continue to be valued at historical cost at that time (but updated to reflect acquisitions at cost, and inflation since that date).[110]

Similarly, the QCA also considered – but rejected – the valuation of easements at current replacement cost in its 2001 review of electricity distribution charges, and instead valued easements for regulatory purposes at book value. In this decision, the QCA commented on the special nature of easements as follows:[111]

As noted above, the Authority has adopted DORC as the general method to be used to determine the value of the regulatory asset base. Furthermore, the Authority accepts that there are arguments as to why this method should apply to all assets including easements.

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[110] IPART, 2003, Regulatory Arrangements for the NSW DNSPs from 1 July 2004 – Issues Paper, November, p.18; IPART, 2003, 2004 Electricity Distribution Price Review – Preliminary Analysis (Secretariat Discussion Paper), September, p.17.

[111] QCA, 2001, Final Determination – Regulation of Electricity Distribution, May, p.59.

> *However, easements are clearly of a somewhat unusual nature and different to other distribution assets. Easements are not likely to be replaced and are not consumed over time. Their value will at times be quite high yet, as they can not be traded, realising their value is extremely difficult.*

In explaining its reasons for the use of book value (rather than current replacement cost) for easements in the current review, its comments included that:[112]

> *Finally, the unilateral adoption by the Authority of a DORC value for easements in circumstances where no other Australian jurisdiction currently uses this approach has the potential to distort relative distribution prices across jurisdictions and this may have unintended economic consequences due to the price signals it would send.*
>
> *The question of the most appropriate method for valuing easements is a difficult issue that is the subject of ongoing work by regulators around Australia although, as yet, there is no consensus view as to the best approach.*

QCA noted that it would consider further the issue of the valuation of easements in future reviews. In its consultation paper released in April 2003, QCA does not foreshadow a strong preference for any of the potential asset valuation methodologies.[113]

It follows from the discussion above that the appropriate approach to value easements for regulatory purposes was in a state of some uncertainty prior to the sale of ETSA Utilities, and that uncertainty remains to some extent to the current period. However, it cannot be concluded that the weight of regulatory precedent supported valuing easements at their current replacement costs. In contrast, the weight of precedent supports the valuation of existing easements with reference to their actual acquisition cost, with the dominant approach in electricity distribution merely to use the book (historical cost) value or not apply a value to the easements in existence at the commencement of formal cost-based regulation at all.

Having regard to all the issues discussed above, the Commission has decided that, in respect of easements and land in existence and in service as at 1 July 1999, the value which will be ascribed to those "sunk assets" in the price determination will be $45.5m, consistent with the regulatory asset base which was established in South Australia. As with all other regulatory asset values, this value will be rolled forward in the manner outlined in this chapter.

9.2.7 Capital Works in Progress

Capital works in progress are not an independent class of assets, but rather assets that are partly constructed (ie have not entered into service). There are two options for treating the time at which assets are reflected in the regulatory asset base:

- at the time the regulated entity incurs expenditure on an asset; and

112 QCA, 2001, Final Determination – Regulation of Electricity Distribution, May, p.61.

113 QCA, 2003, Electricity Distribution: Valuation of Easements, April.

- at the time at which the asset enters into service.

The first option would imply including capital works in progress. Under the second option, capital works in progress would be excluded, but the financing cost incurred prior to the asset being commissioned would need to be included in the regulatory asset base. The approaches should have an identical financial effect on ETSA Utilities.

The current approach recognises capital expenditure at the time that expenditure is incurred. The Commission does not consider that there is a reason to change the current treatment for capital works in progress. As such, the Commission will recognise capital expenditure at the time at which expenditure is incurred, which implies including capital works in progress, but excluding an allowance for the cost of financing during the construction stage (often referred to as 'accumulated funds used during construction').

9.2.8 Assumptions for Final Year Capital Expenditure

Given that the Price Determination will be made prior to the end of the last year of the 2000-2005 regulatory period, the Commission is required to make assumptions about the capital expenditure, contributions and disposals for the final year of the initial regulatory period.

This assumption has important implications for ETSA Utilities' incentives to be efficient in the last year of the regulatory period, and so has been considered by the Commission in the context of the efficiency carryover mechanism, discussed in Chapter 6 of this determination.

For the purposes of asset roll forward, the Commission will include an amount of capital expenditure for the final year of the initial regulatory period equal to the benchmark capital expenditure for that year plus a forecast of the capital expenditure expected in respect of pass-through events for that year.

9.3 Regulatory Depreciation and Asset Stranding

9.3.1 Regulatory Depreciation

Consistent with the financial capital maintenance concept, regulators have seen depreciation as an annual rate at which capital is returned to investors. The regulatory asset base represents the regulator's view of the market value of the regulated business at any point in time.

One of the objectives outlined in the NEC is to create an environment which fosters efficient operating and maintenance practices within the distribution sector (clause 6.10.2(e)). To achieve this objective, the Commission considers that ETSA Utilities should at least be permitted to have its invested capital returned at a rate that

provides certainty over the recovery of the *regulatory asset base* in the future.[114] Thus, to the extent that technological change may be expected to place a constraint on the prices it can charge – and hence the capital it can have returned – in the future, then efficiency requires that it be permitted to recover a greater share of its capital earlier. Indeed, it is noted that, given the capital-intensity of electricity distribution and the longevity of the assets, it is likely to be beneficial for the depreciation methodology adopted to err on the side of providing ETSA Utilities with a safety margin against the impact of unforeseen technological change.

Beyond the minimum rate of depreciation implied by the above paragraph, the Commission noted that economic efficiency concerns imply that attention should be placed on whether the resulting time path of prices is expected to be efficient, which may be a complex task.

In view of establishing the 'theoretically correct' depreciation regime, the Commission proposes to continue the current approach to regulatory depreciation – straight line, inflation indexed over the economic lives of the assets, provided that the desired consistency can be achieved between the market and regulatory value of assets that may be disposed of. It notes that this is the standard approach to regulatory depreciation for energy distributors in Australia.

9.3.2 Asset Stranding

Related to the issue of regulatory depreciation, a question typically addressed by Australian regulators is whether the regulator should try to identify specific assets that it considers to have been 'stranded' when rolling-forward the regulatory asset base[115]. Regulatory 'stranding' in this context refers to the process by which the regulator would adjust the regulatory asset base to reflect a *perceived* decline in the economic value or use of the assets, without compensating owners for the reduction in asset value through an increased regulatory depreciation allowance.

Clause 7.2(e) of the EPO precludes the Commission from 'stranding' ETSA Utilities' fixed assets in such a way. Notwithstanding this requirement, the Commission questioned whether reserving the power to 'strand' assets would deliver benefits commensurate with the cost.

The main justification for threatening to 'strand' assets is that such a threat may provide additional incentive for the regulated entity only to undertake efficient investment. The main argument for providing such an incentive is that the regulated entity is likely to have more information than the regulator about the efficiency of a proposed investment. Therefore, placing more responsibility on the

[114] An alternative way of stating this principle is that regulatory depreciation should at least keep pace with any external constraints that may affect the price that ETSA Utilities can charge for distribution services in the future.

[115] For example, the NEC refers to the re-optimisation of the regulatory asset base at regular periods. The National Gas Code also permits the regulator to specify in advance whether and, if so, how, it will identify and treat stranded assets. In this case, the regulator is also required to take account of this policy when setting regulatory depreciation and the regulatory rate of return.

regulated entity as to the efficiency of the investment is likely to reduce the likelihood of inefficient investment.[116]

However, other tools exist for encouraging efficiency in investment. In particular, an objective behind the CPI-X price path and efficiency carry-over that will apply to ETSA Utilities is to encourage only efficient investments to be undertaken. Moreover, credible threats to strand assets are likely to impose tangible risks on investors, which may have a dampening effect on their preparedness to invest, particularly in the absence of a predetermined methodology for quantifying the level of stranded assets.

Another justification forwarded for asset 'stranding' is that such an approach replicates a competitive market outcome. The Commission notes that if owners of distribution networks are exposed to the threat of stranding, then compensation for the potential for assets to be declared to be 'stranded' by the regulator would need to be factored into prices. The Commission does not consider that the potential improvements in efficiency that may flow from threats to strand assets would exceed the additional compensation required to ensure that investment continues to be attracted in the presence of a stranding threat, particularly given that:

- the stranding threat would be a regulatory construction (rather than the outcome of a market process) which could involve a substantial subjective element; and
- the price cap and carry-over mechanisms already provide ETSA Utilities with an incentive to reduce cost, which is considered a more targeted mechanism for ensuring cost-efficiency than the threat of asset stranding.

The Commission has therefore decided not to adjust ETSA Utilities' regulatory asset base to take account of "stranded" assets.

9.4 The Building Block Formula

One of the issues that the Commission needs to form a view upon is the most appropriate technical formula for deriving annual revenue benchmarks. This formula would need to ensure that the expected costs associated with financing the regulated activities were compensated for, where those financing costs may relate to capital expenditure undertaken, as well as operating activities. If an entity bears a financing cost associated with operating activities – which would arise where operating expenses are incurred on average in advance of revenue being received – then a requirement for *working capital* is generated (with the financing cost approximated by the required return on that stock of working capital).

[116] On this point, it is noted that where there are choices of technology available to meet growing demand that either come in large increments or in modular form, then the uncertainty over future demand may affect the optimal technology choice.

The price controls that applied over the 2000-2005 regulatory period were determined on the basis of revenue benchmarks, calculated using the following formula (ignoring inflation):

$$Revenue\ Benchmark_t = WACC \times \left(Open\ AV_t + \frac{Capex_t}{2} \right) + Dep_t + O\&M_t \qquad (1)$$

where *Open* AV_t is the opening asset value for year t, $Capex_t$ is the forecast capital expenditure for year t (net of customer contributions), Dep_t is the regulatory depreciation allowance for year t and $O\&M_t$ is the forecast operating and maintenance expenditure for year t.

The implicit assumptions about the timing of revenue and expenses in the revenue benchmark formula that were used to set current price controls are as follows:

- half of the capital expenditure is incurred at the start of the year and the remainder at the end;
- the timing of operating expenses and the portion of revenue in respect of operating activities are aligned; and
- all of the revenue in respect of the invested capital (depreciation and the return on assets components) is received at the end of the year.

Intuition would suggest that this formula is likely to lead to a revenue benchmark that overstates the cost of providing the distribution services. In particular, as revenue would be received over the course of a year, the assumption that the share of revenue in respect of invested capital is received at the end of the year will understate the value of this revenue stream (and so overstate the revenue required to equate with cost, in present value terms).

Given that the majority of revenue reflects a return on and of assets that were in place at the start of any year, the upward bias in the revenue benchmark would be expected to be significant. In addition, the implicit assumption that capital expenditure is (approximately) spread over the year – but that all revenue is received at the end of the year – does not appear to have any clear justification.

The other Australian energy regulators generally adopt either one of two target revenue formulae, which are (ignoring inflation and taxation):

$$Revenue\ Requirement = WACC \times \left(Open\ AV_t + \frac{Capex_t}{2} - \frac{Dep_t}{2} \right) + Dep_t + O\&M_t \qquad (2)$$

and

$$Revenue\ Benchmark = WACC \times \left(Open\ AV_t \right) + Dep_t + O\&M_t \qquad (3)$$

The difference between equation 1 and equation 2 (the average asset value equation) is that the latter assumes that half of the *net capital invested* (rather than half of the *gross*

capital invested) in the business is incurred on the first day of the year and the remainder at the end. In contrast, the former assumes that the net capital invested is the difference between capital expenditure and the return of invested capital (regulatory depreciation). Netting off the cash returned to investors through regulatory depreciation is a more reasonable assumption.

However, equation 2 still assumes that the bulk of revenue is received at the end of the year, and so is likely to overstate the revenue actually required. Equation 3 assumes that all revenue and all costs are incurred at the end of the year. This assumption is likely to understate the cost of providing the regulated services, but also understate the value of revenue – and the latter would be expected to dominate. However, the complexity associated with computing the difference between understated costs and revenue does not justify the marginal improvement that this method may deliver.

In its most recent review of distribution charges for electricity distributors, the then Victorian Office of the Regulator-General (now Victorian Essential Services Commission) adopted the revenue benchmark formula consistent with equation 2, and undertook an empirical test of whether this formula was likely to significantly under or overstate the revenue actually required to equate with cost, in present value terms.[117] It found that, while the target revenue formula understated the revenue required in respect of operating activities (that is, there was a working capital requirement), it overstated the revenue required in respect of invested capital – and the latter dominated by a margin (that is, the net effect was an overstatement of the revenue required). However, it chose not to pursue a more complex revenue benchmark formula, but also ruled out providing an allowance in respect of working capital. The ACCC has adopted the same analytical approach – and reached a similar conclusion – in relation to gas transmission.[118]

Given the likely similarities in the within-year timing of cash flow between ETSA Utilities and the Victorian electricity distributors, it would appear that the empirical results derived by the Victorian Essential Services Commission are relevant to South Australia. This would suggest that the use of the equation 2 target revenue formula may be appropriate. An alternative would be to undertake an empirical analysis of the within-year timing of cash flow for ETSA Utilities, and potentially to derive a target revenue formula that provides a closer fit to costs.

The Commission recognises that this methodology is different to the one that was used to derive the current prices in the EPO. However, the Commission considers that the current methodology is incorrect and provides a windfall to ETSA Utilities. This is inconsistent with the objectives and principles outlined in the NEC, including the objectives of prevention of

[117] The analytical approach adopted by the then Victorian Office of the Regulator-General is set out in Office of the Regulator General (Vic), Electricity Distribution Price Determination 2001-05, pp.113-117

[118] ACCC, Final Decision: Access Arrangement Proposed by GasNet Australia for the Principal Transmission System, November 2002, p.174; ACCC, Final Approval: Access Arrangement proposed by Epic Energy for the Moomba to Adelaide Pipeline System, July 2002, pp. 11-13.

monopoly rent and of having regard to the principle of balancing the interests of Distribution Network owners and network users with the public interest.

Accordingly, the Commission's decision is to adopt the following revenue requirement formula:

$$Revenue\ Requirement = WACC \times \left(Open\ AV_t + \frac{Capex_t}{2} - \frac{Dep_t}{2} \right) + Dep_t + O\&M_t$$

9.4.1 Working Capital

The final issue on regulatory asset base for the Commission is whether to include an allowance in respect of working capital.

A working capital requirement arises where operating expenses are paid in advance of revenue receipts which creates a cost of financing those operating activities. Accordingly, a proposition that an additional allowance in respect of working capital is required is equivalent to a conclusion that the implicit assumptions in the revenue benchmark formula about the timing of cash flows in relation to *operating activities* may not reflect the true timing of this subset of cash flow, and thus ignore a financing cost.

It is noted that the approach to assessing the appropriateness of the different revenue benchmark formulae set out above – and the need for a working capital requirement – imply a degree of precision in the analysis that may appear unjustified, given the potential bounds of uncertainty in the inputs required to generate revenue benchmarks. The Commission appreciates this concern, and has a preference for a simple approach to deriving revenue benchmarks where possible (which is reflected in the proposed approach set out below).

The Commission acknowledges that ETSA Utilities may have a reasonable expectation that an appropriate amount of working capital will be included in its regulatory asset base. Nevertheless, the Commission does not consider that the stock of working capital that was assumed when calculating the current price caps ($80 million as at 30 June 2000) can provide an accurate estimate of the cost of financing operating expenditure.

In particular, as ETSA Utilities' operating expenditure for the financial year ending 30 June 2003 was $91 million, such a stock of working capital implies an assumption (approximately) that all operating expenditure is incurred on the first day of the year, and all revenue is received on the last day, which is clearly implausible.

Whilst the Commission has not been provided with a model that calculates the working capital requirement that was assumed in the current price caps, from the information that it has been able to obtain, it has the following concerns.

First, even though the purpose of the regulatory return on working capital is to compensate for the cost of financing *operating expenditure*, the calculation of the stock of working capital appeared to reflect the value of *all* unbilled consumption and revenue receivable. As more than 70 per cent of the revenue received by ETSA Utilities reflects *capital-related costs* (ie return on assets and depreciation), this calculation will overstate considerably the cost of financing the operating-only portion of expenditure.

Secondly, the calculation appeared to include amounts in respect of other accounts receivable, which were not relevant to regulated distribution charges.

The Commission considers that the appropriate calculation for the allowance of working capital would need to meet the following principles:

- Firstly, it would need to relate only to the cost of financing operating expenditure;
- Secondly, the calculation would need to relate only to revenue and expenses relevant to prescribed distribution charges; and
- Thirdly, the calculation would need to reflect benchmark assumptions about the timing of cash flow in order to avoid compensating imprudent or inefficient activities.

The Commission notes that a focus on the cost of financing operating activities (excluding the share of revenue that is associated with capital costs from the calculation) as proposed above would appear consistent with the computation of working capital allowances in at least some jurisdictions in the US:[119]

> *Rules-of-thumb allowances ... often overstate the proper working capital allowance by including cash held for payment of interest, dividends or maturing debt. The inclusion of working capital for those purposes would duplicate allowances already given in the rate of return.*

One potential methodology would be to make explicit assumptions about the timing of revenue and operating expenditure over a year, and to use discounted cash flow analysis to calculate the net financing cost incurred from receiving revenue at a lag to incurring operating expenditure.

An alternative methodology that would be simpler – but more approximate – would be to make explicit assumptions about the extent to which revenue is received at a *lag*, and about the extent to which operating expenditure is incurred after an activity has been performed (a *lead*), and to estimate the stock of working capital as:[120]

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[119] Goodman, L., 1998, *The Process of Ratemaking*, (Public Utilities Reports, Vienna, VA), p.830.

[120] The use of 'lead-lag' study reflects the method of computing working capital allowances in a number of US jurisdictions, and is described in: Goodman, L., 1998, The Process of Ratemaking, (Public Utilities Reports, Vienna, VA), pp.828-838. The Independent Gas Pipelines Access Regulator (WA) has applied a lead-lag approach to the derivation of required working capital: Independent Gas Pipelines Access Regulator (WA), 2000, AlintaGas: Final Decision, Part B, pp.114-117. The WA regulator assumed a net lag of 100 days '[by] reference to other gas distributors in Australia' (p.114), although there is no further discussion of how this figure was derived.

$$Working\ Capital = \left(\frac{Lag(Days) - Lead(Days)}{365} \right) x\ Operating\ \ Expenditure$$

The Commission's preliminary calculations suggest that, on the basis of the known metering cycle in South Australia and information contained in the Information Memorandum for the sale of ETSA Utilities, the net lag in the compensation for operating expenditure would be no greater than approximately 39 days. This figure was calculated as:

- a *revenue lag* of **73 days**, which comprises unbilled consumption of 45 days (ie half of the standard 3 month meter reading cycle) and an average time between meter reading and bill payment (accounts receivable) of 10 days;[121] and
- an *expense lead* of **34 days**.

A net lag of 39 days would imply a required stock of working capital of approximately 11 per cent of annual operating expenditure, which in turn would imply approximately $30 million for the average operating expenditure over the 2005-2010 regulatory period.

The Commission has decided that an amount of $30m will be included in the regulatory asset base as working capital for the 2005-2010 regulatory period.

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[121] By assuming unbilled consumption of 45 days, it is assumed implicitly that all customers have their meters read quarterly. In practice, industrial customers' meters are read monthly, and so average unbilled consumption would be lower.

10 REGULATORY RATE OF RETURN

Capital (or investment funds) can be regarded as a tradable commodity with price determined by supply and demand. The cost (price) of capital is dependent upon the aggregate demand and supply of investment funds, and the risk in cash flows potentially generated by the asset relative to the risk associated with other assets. Unlike the price for most goods and services, the price for investment capital cannot be observed, but must be estimated from other market information. Thus, determination of the return to be assumed in the revenue benchmarks requires the estimation of the cost of capital associated with the regulated activity, as implied by the market.

While there is a 'true' cost of capital for any activity *in theory*, any estimate of the cost of capital is subject to a large degree of statistical uncertainty or imprecision. The capital intensive nature of electricity distribution makes the estimate of the cost of capital one of the more significant inputs in the review of price controls, and has been a matter of some debate and controversy in matters before other regulators.

Accordingly, how the Commission addresses this imprecision when estimating the cost of capital, in light of the statutory imperatives of the National Electricity Code ("the NEC"), the Electricity Pricing Order ("the EPO") and relevant legislation, is an important issue, which is discussed in this chapter.

A key objective when determining the regulated rate of return that is assumed in the revenue benchmarks is to provide investors with a return that is sufficient to motivate the investment and attract the capital away from alternative investments. In this sense, the regulatory rate of return should reflect an opportunity cost of capital – the return on capital available to investors in the next-best investment opportunities, adjusted for the relative risk of the projects.

As the assets employed by a firm are generally financed by a combination of debt and equity, part of the returns that accrue to a particular asset flow to debt providers and part to equity holders. Accordingly, the term weighted average cost of capital, or WACC, is often used to refer to the market-determined cost of capital for a particular asset, reflecting the fact that the overall return to an asset comprises a return to both lenders and equity holders.

10.1 Consultation

The Commission has released two consultation documents that include issues relating to the determination of the regulatory rate of return[122]. The Commission received a number of submissions on these consultation papers. All submissions received during this

[122] The Commission has previously released two Papers on "Return on Assets"; Discussion Paper, August 2003 (http://www.escosa.sa.gov.au/resources/documents/030818-R-ElectReturnOnAssets_DiscPaper.pdf), and "Preliminary Views" January 2004 (http://www.escosa.sa.gov.au/resources/documents/040114-R-EDPR-ReturnOnAssets-PrelimViews-Final.pdf).

consultation process have been given consideration prior to making this Draft Determination.

10.2 Legislative Requirements

Clause 7.2(c) of the EPO requires the cost of capital to be calculated in accordance with the Reset Schedule (Schedule 10 of the EPO), unless ETSA Utilities consents to depart from the Reset Schedule. The methodology required by the Reset Schedule to estimate the cost of capital is reproduced in Figure 10.1.

Figure 10.1: Schedule 10 - Reset Schedule

SCHEDULE 10. RESET SCHEDULE

1. Adopt the Capital Asset Pricing Model (CAPM) adjusted for the presence of debt through the Weighted Average Cost of Capital (WACC) adjusted to a pre-tax real basis.

2. The post-tax nominal WACC model adopted shall be as follows:

$$WACC = k_e \frac{E}{V} + k_b (1 - t_c (1 - g)) \frac{D}{V}$$

where:

k_e	=	cost of equity, defined as $k_e = r_f + b_L \times MRP$

where:

k_e	=	cost of equity capital after corporate tax
β_L	=	the levered or equity beta
r_f	=	risk free rate
MRP	=	market risk premium
k_b	=	cost of debt, defined as kb = rf + debt risk premium
t_c	=	the corporate tax rate
γ	=	value (pre-personal tax) of $1 of imputation credits. In essence this is the proportion of company tax which gives rise to the tax credit associated with a dividend with attached imputation credits.
E	=	market value of equity
D	=	market value of debt
V	=	E + D

3. In transforming the WACC to a pre-tax real WACC, the sequence to be adopted is the standard approach of commercial practitioners and involves the following:

   (a) gross up the post-tax nominal WACC to a pre-tax nominal WACC by the imputation-adjusted corporate tax rate, t_e; where $t_e = (1 - t_c (1 - g))$; and

   (b) deflate the resulting pre-tax nominal WACC to a pre-tax real WACC using the Fisher equation.

4. In estimating r_f, the risk free rate, the approach to be adopted should ensure proper matching with the life of the underlying assets. For long lived assets the benchmark should reflect the yield on the longest dated government bond supported by the market and be consistent with the definition and measurement of the market risk premium.

5. Except for exceptional circumstances the term for the benchmark risk free security shall be the ten-year government bond. Furthermore the benchmark for the risk free rate should reflect the average yield over the last five years on a rolling average basis.

6. In all other respects the estimation of parameters shall reflect prevailing conditions in the market for investments having a similar nature and degree of business risks as those faced by ETSA Utilities.

The provisions of the EPO set out above dictate the required approach for a number of important methodological issues, some of which have been a source of some controversy. These include the treatment of taxation, and the appropriate proxy for the risk free rate. There are nevertheless other important areas where the Commission is required to exercise its judgement.

Subject to the NEC, the Commission is bound by the terms of the EPO in relation to the estimation of input parameters for the capital asset pricing model (CAPM). The EPO requirements on the rate of return is unambiguous: where the Commission needs to take into account a rate of return, it must follow the imperatives of the Reset Schedule, including the imperative that the estimation of the parameters of the CAPM must reflect prevailing conditions in the market for investments having a similar nature and degree of business risk as those faced by ETSA Utilities. This is the threshold test to be applied to estimation of CAPM parameters. In doing this, the Commission has received expert advice on aspects of this draft determination.

At the same time, clause 7.2(k) of the EPO requires that the Commission must have regard to any relevant interstate or international benchmarks for prices, costs and returns on assets in private sector industries comparable to those in which ETSA Utilities operates.

The Commission considers that decisions by other regulators on the cost of capital, and the assumption that was made by the South Australian Government when it set the current price caps, are relevant to the application of these clauses. Decisions by other regulators and the assumptions adopted by the Government are estimates adopted by others of values that reflect 'prevailing conditions', and hence provide evidence of the values required by paragraph 6 of the Reset Schedule, provided that the relevant decision reflects investments having a similar nature and degree of business risk as those faced by ETSA Utilities. Similarly, other regulators' decisions on the cost of capital for privately owned entities, as well as the assumptions that were adopted by the Government when setting the current price caps, would be benchmarks of the type contemplated by clause 7.2(k). The EPO expressly contemplates the Commission having regard to such benchmarks when deciding on the value for the cost of capital that best meets the requirements of paragraph 6.

In terms of the NEC, the Commission is to be guided by the overall objectives set out under clauses 6.10.1 to 6.10.3. These objectives are broad ranging and in some cases may be conflicting. For example, the achievement of an efficient and cost effective regulatory environment may not be achieved by rigorously pursuing the objective of achieving certainty and consistency over time. Regulators are continuously improving their understanding of regulatory issues, including issues relating to WACC. This improved understanding over time may require changes to be implemented from one regulatory period to another (within legislative obligations) to better achieve the overall objectives. Hence the NEC allows for significant judgement by the Commission in estimating CAPM parameters.

In line with its earlier observations on the interactions between the various regulatory instruments which impact on the Commission's price determination process, the Commission would also observe that for some discrete decisions, neither the EPO nor the NEC expressly dictate the manner in which the issue is to be resolved. In such cases the Commission will inform its deliberations in accordance with the various discretionary factors of the NEC, the EPO, the Electricity Act and the ESC Act, bearing in mind the intersection of each.

10.3 Methodology for Estimating the Cost of Capital

Clause 1 of the Reset Schedule requires the cost of capital associated with the equity-financed portion of the regulated activity to be estimated using the CAPM and for the cost of capital associated with the asset then to be derived as a weighted average of the cost of equity and debt finance (with the relative shares of these sources of finance used as the weights).

While it is bound to utilise the CAPM, it is likely that the Commission would have adopted that model in any event, as it considers the CAPM to be the most appropriate model to guide the estimation of the cost of capital associated with the regulated assets. Australian regulators commonly use the CAPM, as do the regulators in the UK. It is also used extensively by financial market practitioners, when valuing assets.[123] It is also understood that the CAPM was used by the Government to guide its estimate of the cost of capital associated with ETSA Utilities' regulated activities when setting the current price controls.

The version of the CAPM specified in the Reset Schedule defines the cost of equity as the sum of the return available on a risk free asset and the premium required to accept the risk associated with the specific asset. That is:

$$k_e = r_f + b_L \times MRP$$

The risk free rate, r_f, is the return that investors would require in order to hold a risk free asset. The premium for the specific asset's risk depends upon the return required on a well-diversified portfolio of investments (the market risk premium), and the risk of the specific asset relative to that well-diversified portfolio. In this context, risk reflects the variability of net cash flows.

Of the CAPM parameters, only the ß (beta) is specific to any particular asset – all other inputs are economy-wide factors that affect the required rate of return on all assets. By definition the well-diversified portfolio of assets has a beta of one, more risky assets have a beta of more than one, and less risky assets have a beta of less than one.

10

[123] The dividend growth model (DGM), rather than the CAPM, is the dominant tool for estimating costs of capital for regulatory matters in the US. The parameter in the DGM that is difficult to estimate is the expected growth in dividends. In the US, the large number of forecasts of dividend growth by equity analysts provides a reasonably robust basis for deriving an estimate of the expected growth rate in dividends. In contrast, only a few forecasts of dividend growth are available for Australian listed utilities.

It is important to understand the type of risk that is relevant to the cost of capital associated with an asset. Investors can eliminate much of the risk associated with a particular asset by holding that asset as part of a portfolio. As this portion of risk can be eliminated at no cost, this portion of risk – often termed 'diversifiable risk' – would not be compensated for in a competitive capital market. It is only the remaining risk – the non-diversifiable risk – that is reflected in the cost of capital associated with an asset.[124] The non-diversifiable portion of an asset's risk reflects the variation in its return that is related to movements in a well-diversified portfolio of assets, and as such tends to reflect the variation in returns associated with market-wide factors – such as business cycles.

It has been noted in a number of other regulatory proceedings that the diversifiable component of risk may be relevant because this portion of risk should be factored into forecasts of cash flow (or, in a regulatory setting, in forecasts of future expenditure and revenue). A number of regulated entities have then extended this argument to conclude that the regulator's forecasts are likely to exclude a class of events, and hence a premium may be required in respect of these omitted events. This issue is discussed separately in section 10.9.

The form of the CAPM discussed above provides an estimate of the required (after tax) return on equity. However, as the objective is to obtain an estimate of the cost of capital associated with the asset, the estimate of the required equity return is an intermediate input.

The other required input – an estimate of the expected return to debt providers – is normally obtained on the basis of the observed cost of debt as issued or traded in the market. The average of the estimated cost of equity and the estimated cost of debt financing (weighted by the respective shares of equity and debt in the financing of the asset) can then be used as an estimate of the WACC for the asset.

The CAPM and WACC discussed above provide an estimate of the cost of capital in after (company) tax terms. However, as ETSA Utilities will be liable for Australian company tax, an allowance for the expected company tax expense is required. While this issue has been controversial in other regulatory proceedings, the Reset Schedule prescribes a particular methodology for deriving this allowance. As a result, the Commission has no discretion as to this derivation and is bound by the terms of the EPO. The derivation of an allowance for taxation requires an assumption about the value of franking credits, which has also caused controversy. These issues are discussed in sections 10.7 and 10.8 of this chapter.

Unless specified otherwise, the Reset Schedule requires the estimation of WACC parameters to reflect prevailing market conditions in the market for investments having a similar nature and degree of business risks as those faced by ETSA Utilities.

[124] The CAPM provides an estimate of the return required to compensate for the non-diversifiable component of risk only. However, the conclusion that no compensation should be provided for diversifiable risk is relevant to all of the models from finance theory that could be used to estimate costs of capital.

The application of the methodology discussed above requires updated estimates of a number of parameters, including:

- the risk free rate of return and the inflation forecast;
- the beta associated with the regulated activities of ETSA Utilities;
- the market risk (equity) premium;
- the assumed financing structure and debt premium associated with the regulated activities of ETSA Utilities; and
- the treatment of taxation and dividend imputation.

These issues are discussed in the following sections. First, however, the Commission's Draft Determination with respect to the timing of the determination of the WACC is discussed.

10.4 Timing of the Final WACC Estimate

While the Commission intends to state views on its estimates of as many variables as possible in this Draft Determination paper, it considers that there are inputs in its WACC estimate that it will derive directly from the capital markets, for which it would be straightforward – and reasonable – to update to reflect the latest market data when making the Final Determination in March 2005. The inputs that the Commission would envisage updating are:

- the nominal and real government bond rates (see section 10.5);
- the yield on corporate bonds (see section 10.6.8); and
- the corporate tax rate (see section 10.7) [125].

The Commission proposes to finalise its estimate of the cost of capital associated with ETSA Utilities' regulated activities as at 11 February 2005; that is, approximately in the middle of the month prior to its planned release of the Final Determination. Therefore, the inputs set out above will be averaged over the relevant period to that date (in the case of government and corporate bond yields) or taken as at that date (the prevailing corporate tax rate).

10.5 The Risk Free Rate and the Inflation Forecast

Where regulatory asset values are escalated for actual inflation over a regulatory period, the real (rather than the nominal) risk free rate is the important input to the estimation of the cost of capital. Where tariffs are escalated for inflation, then a real return is provided (and the real risk free rate is the relevant measure of the risk free rate), irrespective of how the cost of capital estimate is expressed.

In estimating the risk free rate, the Reset Schedule requires that:

[125] This input will only change if changes to the statutory tax rate from 30 per cent have occurred or have been announced as at 11 February 2005.

- except for exceptional circumstances, the yield on ten-year government bonds should be used as the benchmark for the risk free rate; and
- the estimate should reflect the average yield over the last five years on a rolling average basis.

Thus, the Reset Schedule specifies only the methodology to be used to derive a nominal risk free rate. Accordingly, the assumption about expected inflation that is adopted is an important input. The issues associated with this forecast are discussed below.

10.5.1 Choice of Inflation Forecast

In its previous consultation papers the Commission noted that the dominant methodology used by Australian regulators to forecast inflation involves the use of CPI-Indexed Bonds. As the Commonwealth Government has issued nominal bonds and CPI-indexed bonds, both of which are traded in the market place, the difference between the yields (for bonds of the same term) on these instruments at any point in time provides an updated market view of expected inflation over the relevant period.[126] This can be contrasted with forecasts of inflation from either official sources or market practitioners, which may only be updated infrequently.[127]

Accordingly, the Commission proposed to use the break-even rate of inflation between nominal and CPI-indexed bonds to derive the inflation forecast required to estimate the cost of capital associated with ETSA Utilities regulated activities.[128]

The Commission noted that a particular issue for the derivation of the inflation forecast for the current matter is the period of bond observations that is used to derive the forecast. As the Reset Schedule requires the nominal risk free rate to be calculated using a five-year average of interest rates, a consistent application of the formula requires the inflation assumption to be derived over the same period.

To illustrate, if the real risk free rate had been constant over the period, but nominal bond rates had risen consistently over the period solely due to rising inflation expectations, then matching the historical nominal bond yield with current inflation expectations would create a biased estimate of the real risk free rate that would have been observed over the period (in this case, understating the real risk free rate).

Given the broad support for the use of the difference between inflation-linked and nominal bonds to derive an inflation forecast, the Commission's Draft Determination is to use this methodology to derive inflation forecast.

126 It was proposed to calculate a proxy for the yield on a bond with a 10 year term to maturity by taking a linear interpolation of the yield on bonds with the closest remaining terms. This is particularly an issue for CPI-Indexed bonds, as the existing series have maturity dates that are five years apart (ie 2005, 2010, 2015).

127 Note that for other decisions, such as for setting the price path for AGL SA, the Commission has used official forecasts (of 2.5%) rather than the deriving the forecast from CPI-indexed bonds.

128 As the CPI-Indexed bond series have maturity dates that are five years apart, it is proposed that a linear interpolation be used to derive a proxy yield for the bond of the relevant term to maturity.

The Commission also remains of the view that consistency in the sampling interval between the nominal and real bonds is important for the reasons summarised above. Hence, the Commission's decision is to use a consistent period for the inflation linked and nominal bonds, to determine the inflation forecast. A linear interpolation of available bond yields will be used to generate a proxy for the yield on bonds with a remaining term of 10 years.

Regarding the term of the bonds that are used to derive the nominal risk free rate and inflation forecast, the Commission notes that the Reset Schedule requires 10 year bonds to be used.

For the purpose of this decision, the averages are taken starting from 12 February 2000 to 27 October 2004, and the rates kept constant from thereon until 11 February 2005. These rates derived have been used which provide a nominal risk free rate, real risk free rate and inflation forecast of 5.72 per cent, 3.25 per cent and 2.4 per cent, respectively [129].

The Commission's decision is to determine the forecast of inflation as the difference between the rate of nominal and inflation-indexed bonds that have a term to maturity of 10 years.

The Commission proposes to take the average of nominal and inflation-indexed bonds (and hence, inflationary expectations) measured over the same period (that is, under the Reset Schedule, the previous five years).

10.6 Estimating Beta

While the beta that is used in the CAPM should reflect the expected relationship between returns to a particular asset and the market as a whole, betas can only practicably be measured for a historical period. The estimation of an equity beta for an entity, in practice, requires the relevant entity to be listed on a stock exchange, and with observations available over a reasonable period of time.[130] Beta estimates are also subject to substantial statistical uncertainty.

The fact that most Australian regulated entities are not listed, coupled with the desire to derive a more precise estimate, requires adoption of common practice to use the estimate of the equity beta from a group of firms and to use this as a proxy for the equity beta of the regulated firm in estimating the WACC.[131] Given that a beta for ETSA Utilities cannot otherwise be derived, such an approach is consistent with the EPO's imperative that the Commission is to reflect prevailing market conditions for investments of a similar nature and degree of business risk to those faced by ETSA Utilities in estimating beta.

[129] For reasons noted under section 9.2.2 of this determination, no adjustment for the GST related spike in inflation will be made to the observed yield on index-linked bonds.

[130] Observations over three to five years are normally used to estimate equity betas.

[131] The precision of the average of a group of betas is generally lower than the precision of any Individual firm beta estimate, with the precision rising with the number of firms in the group.

However, before a proxy equity beta can be derived, a number of detailed methodological issues need to be settled on.

10.6.1 Adjusting Beta for Capital Structure

The measured equity beta for a particular firm relates to the unique capital structure of that firm, and a change in the capital structure will change the degree of financial risk borne by the equity holders and hence the equity beta.

In particular, the relative risk of the equity share can be expressed as the sum of:

- the underlying market risk of the asset; and
- the level of financial risk borne by equity holders, which in turn is dependent on the capital structure of the entity.

To allow equity betas to be compared across firms with different capital structures, the estimated equity beta must be converted into an equivalent asset beta (which is the equity beta that would apply if the asset were financed wholly with equity). As an asset beta is purged of the financial risks associated with gearing, it can be compared with other asset betas derived from different capital structures. The asset beta can then be adjusted into an equity beta that is consistent with the target firm's level of gearing. The process of adjusting equity betas for different levels of gearing is known as de-levering and re-levering.

The appropriate approach to de-levering and re-levering adjustments is a matter of debate. The derivation of an appropriate levering/de-levering formula requires assumptions about:

- whether the debt policy is active or passive;
- the marginal tax advantages associated with debt; and
- whether or not debt is risky, the implication of which is whether or not debt providers share some of the risk associated with the asset.

The first two of these points are relevant to the selection of the levering/de-levering formula, and the third to the size of the debt beta. These are discussed in turn.

10.6.2 Levering / De-Levering Formulae

The first of these issues is the method of levering/de-levering the equity beta. There are a number of different formulae for predicting the relationship between equity betas and financial gearing, which reflect different assumptions about the debt management practices of firms and the assumed marginal tax advantages of debt finance. However, the choice between these formulae has little effect on the proxy equity beta that is derived from a set of empirical beta estimates, *provided that* the same levering / de-levering approach is used for estimated asset betas as is used when re-levering asset betas into equity betas for the target level of gearing. This is particularly the case for Australia, where the dividend imputation

system and concessionary treatment of capital gains are likely to reduce the tax advantages of debt finance.[132]

Accordingly, the Commission proposes to use the simplest formula for predicting the relationship between equity betas and the gearing level, which is

$$b_a = b_e \frac{E}{V} + b_d \frac{D}{V}$$

where b_a is the asset beta, b_e is the equity beta, b_d is the debt beta and E/V and D/V are the proportions of equity and debt in the financing of the asset.

10.6.3 Debt Beta

If the expected return on debt $E(r_d)$ is known, then the debt beta can be estimated by manipulating the CAPM, that is:

$$E(r_d) = r_f + b_d MRP \Rightarrow b_d = \frac{E(r_d) - r_f}{MRP}$$

The difficulty with this methodology is establishing the expected return on debt. While the promised yield on debt is typically taken as the expected return on debt for the purposes of estimating the WACC, to the extent that this includes a premium for default or a liquidity premium, then it will overstate the expected bounds for the debt beta.

If the entire margin over the risk free rate is a premium for default or liquidity, then the debt beta will be zero. In contrast, if there is no default premium and the entire margin is a reward for bearing systematic risk, then the yield on debt can be inserted directly into the equation above to establish an upper bound for the debt beta.

The discussion above suggests that there is a feasible range for the debt beta of between zero and the value derived from the reverse-engineered CAPM on the assumption that the yield and expected return on debt are the same. Like the de-levering approach, the choice between debt betas normally would have little effect on the proxy equity beta that is derived from a set of empirical beta estimates, provided that the same debt beta is used for estimating asset betas as is used when re-levering asset betas into equity betas for the target level of gearing. Accordingly, the Commission will use a debt beta value of zero.

[132] The various formulae and their assumptions are discussed in: Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities: Final Report, report by the Allen Consulting Group for the Australian Competition and Consumer Commission, July 2002

10.6.4 Derivation of an Equity Beta

While, in principle, an equity beta should reflect the forward-looking expectation of the relationship between the movements in the returns to a particular equity to the movements in the equity market as a whole, in practice, the historical movements in an equity's economic return relative to the sharemarket are normally used to estimate the expected beta.

As the purpose of estimating the equity beta as an input for the estimation of the (forward-looking) WACC for the provision of electricity distribution services, the usefulness of the proxy beta will depend upon the extent to which the set of comparable firms are similar to the regulated entity, as well as the extent to which the period for which the beta was estimated is a reliable predictor of the future.

The difficulty of making comparisons of beta estimates across countries suggests Australian regulated entities are likely to provide the most reliable source of beta estimates, although overseas entities are often relied upon as a secondary source of information. In particular, as betas are a measure of the strength of the relationship between returns to an individual stock and the (local) share market as a whole, the use of overseas proxies involves an implicit assumption that the strength of this relationship is approximately constant across share markets. In practice, differences in the weights of different sectors, the sensitivity of returns to macroeconomic shocks and differences in taxation and regulatory regimes make this a questionable assumption.

There are a number of Australian firms in infrastructure industries that are traded on the stock exchange where estimates of equity betas may be feasible. As the applicability of these estimates will depend upon the similarity of their operating and regulatory environments, gas and electricity distributors may be considered the most appropriate proxies. The proxies that have been used in similar decisions by Australian regulators are:

- AGL;
- Envestra;
- United Energy (until 15 July 2003);
- Australian Pipeline Trust; and
- AlintaGas.

The relevered equity betas for these companies are listed in Table 10.1.

Table 10.1: Relevered Equity Betas (60 Per Cent Debt-To Assets)

	DEBT BETA=0	DEBT BETA= 0.25
Sep-99	1.02	0.93
Dec-99	0.95	0.87
Mar-00	0.79	0.72
Jun-00	0.98	0.92
Sep-00	0.99	0.92
Dec-00	1.01	0.94
Mar-01	1.01	0.94
Jun-01	0.81	0.75
Sep-01	0.60	0.54
Dec-01	0.58	0.52
Mar-02	0.70	0.65
Jun-02	0.58	0.52
Sep-02	0.36	0.31
Dec-02	0.35	0.30
Mar-03	0.31	0.26
Jun-03	0.34	0.28
Sep-03	0.20	0.17
Dec-03	0.23	0.19
Mar-04	0.23	0.19

Source: Betas were obtained from the Risk Management Service of the Australian Graduate School of Management. The estimates include four years of observations, or the firm's trading history. Firms are only included where there are more than 20 observations. The thin trading betas were used where the test for thin trading was failed at the 10 per cent level of significance.

Gearing is calculated as the average of six month observations of gearing levels over the period over which the relevant beta was estimated. Values for March and September were taken as the averages to the previous quarter. The value of equity is the firm's market capitalisation using share price data from the ASX. The value of debt is taken as the book value of debt from ASIC filings and annual reports. Loan notes are treated as equity (including where the note is interest bearing).

The proxy group between September 1999 and December 1999 included AGL and Envestra only, between March 2000 and December 2001, it comprised AGL, Envestra and United Energy, – in March 2002 it included AGL, Envestra, United Energy and the Australian Pipeline Trust, between June 2002 and June 03 it included AGL, Envestra, United Energy, the Australian Pipeline Trust and AlintaGas, and since September 2003 it has included AGL, Envestra, the Australian Pipeline Trust, AlintaGas and GasNet.

There are a number of methodological issues that need to be settled upon when estimating betas that can have a significant effect on the resulting estimates, which include:

- the frequency with which observations are taken;
- the period over which observations are taken;
- the definition of returns used; and
- the proxy that is used as the market portfolio.

The Commission proposes to address these concerns by looking at derived beta estimates in a number of ways, including those from a credible public source.

One such source widely used by Australian regulators and finance practitioners is the Australian Graduate School of Management (AGSM) Risk Management Service. This service provides beta estimates for all companies listed on the

Australian stock exchange, using monthly observations over the previous 48 months (with a minimum of 20 observations).

A common "market practice" is to make a "Blume adjustment" to the beta value. The Blume adjustment involves adjusting observed betas towards one, which reflects an observed tendency for betas to move towards one over time. However, the Commission notes that the Victorian ESC has found that the Blume adjustment is inappropriate for the regulatory context irrespective of "market practice",[133] and the Commission agrees with the Victorian ESC's findings on this matter. In particular, it notes that the equity beta required is for ETSA Utilities' regulated activities only, and is consistent with the benchmark gearing level of 60 per cent debt-to-assets. Accordingly, it would be misleading to take into account the tendency for betas of firms to migrate towards one, due to diversification of activities and changes to gearing levels, and would result in the beta estimate not reflecting "prevailing conditions" in the market for investments having a similar nature and degree of business risk as those faced by ETSA Utilities.

The Commission notes that, if the Commission were to have regard exclusively to the latest market evidence, it would adopt a re-levered equity beta of approximately 0.3. However, the results presented in Table 10.1 show the statistical imprecision in the current beta estimates – with the average for the group varying between the current approximately 0.2 and approximately 1.0 over the last few years. While some of this variation reflects changes to the composition of the group, much reflects variation in the individual beta estimates.

Whilst the Commission considers there are sound reasons for relying as much as possible on objective market evidence when deriving all of the inputs into the cost of capital, it is concerned at the apparent lack of precision with the current market evidence. In particular, it considers that there is a risk that a beta of 0.3 or lower re-levered for an assumed gearing level of 60 per cent debt-to-assets may reflect a short-term aberration.

10.6.5 Estimation of Betas and the Influence of the Technology Bubble on Beta Estimates

Betas estimated using four or five years of observations will include the period over which the 'bubble' in technology related shares took place. It has been argued by a number of commentators that the 'bubble' has substantially reduced the measured betas for US utility firms over the period, making those betas an unreliable guide to the future.

In order to avoid the possible effects of the 'bubble', beta estimates are also provided over a shorter interval (60 weeks) using more frequent sampling (weekly

[133] Essential Services Commission, 2002, Review of Gas Access Arrangements – Final Decision, October, p346.

data). The current 60 month beta estimates include the period after August 2000, and so include much of the period of the new economy bust / utility boom, above. In contrast, the 60 week beta estimates would have been free of the effects of the utility boom after about February 2003.

It is noted that while the use of shorter periods of observations and more frequent sampling of observations may contrast with the typical beta book methodologies, this approach is not uncommon amongst market practitioners, particularly where there are good reasons to consider the more distant past an unreliable guide to the future.

Australian Evidence

Table 10.2 shows the latest estimates of betas for the five Australian comparable entities that are still listed of the Australian stock exchange for both the 60 weeks of weekly observations, and 60 months (five years) of monthly observations.

Table 10.2: Recent Beta Estimates: Australian Proxy Group

ENTITY	WEEKLY SAMPLING			MONTHLY SAMPLING		
	BETA	GEARING	RE-LEVERED BETA	BETA	GEARING	RE-LEVERED BETA
AGL	0.57	29%	1.02	-0.12	35%	-0.19
ALINTA	1.14	29%	2.03	0.44	33%	0.73
AUSTRALIAN PIPELINE TRUST	0.35	53%	0.41	0.51	45%	0.70
ENVESTRA	0.83	73%	0.56	0.10	76%	0.06
GASNET	0.06	67%	0.05	-0.13	66%	-0.11
AVERAGE	**0.59**	**0.50**	**0.82**	**0.16**	**0.51**	**0.24**

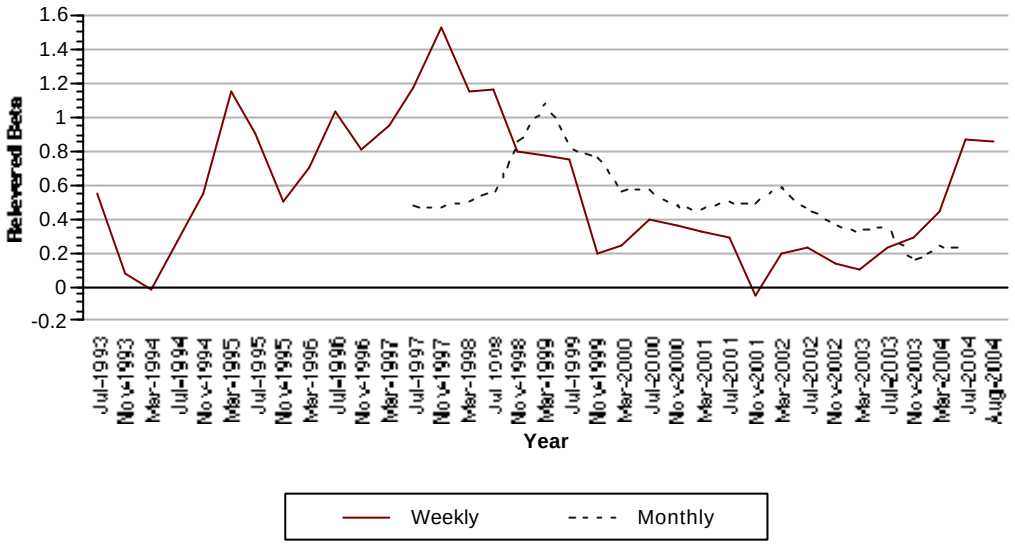
Source: ACG analysis, data obtained from Bloomberg. The 'weekly sampling' comprises 60 weeks of observations, and the 'monthly sampling' comprises 60 months of observations.

For all of the firms, the 'weekly' beta estimates are higher than the 'monthly' estimates, which provide some support for the proposition that the technology bubble may have had an artificial dampening effect on betas in Australia that were measured over the bubble period. The more recent evidence (60 week beta estimates) suggests that if the Commission were to place exclusive reliance on the current market evidence, a beta of 0.82 would be considered appropriate for a regulated Australian electricity distributor. Note, however, that the beta estimate still has a wide confidence interval – its 95 per cent confidence interval is approximately 0.82 ± 0.47.

The results set out above suggest that there is a material risk that the beta estimate that would be provided by the use of observations over the past 5 years (which include the 'bubble') may materially understate the expected (future) beta for this activity.

Figure 10.2 provides further illustration of how the technology related bubble might have affected beta estimates over the bubble period. This figure shows the 'rolling' beta estimates over the period since the start of 1993 for the 'weekly' beta estimates and since July 1997 for the 'monthly' beta estimates.

Figure 10.2: Australia – Average Across The Proxy Group



Source: ACG analysis, data obtained from Bloomberg. The 'weekly' line is weekly sampling and 60 weeks of observations, and the 'monthly' line is monthly sampling and 60 months of observations.

This figure shows that the 'weekly' beta estimates tend to lead to 'monthly' estimates, reflecting the fact that the 'weekly' estimates are more quickly affected by more recent developments. The 'weekly' estimates – after hovering between about 0.6 and 1.4 since the end of 1994, started to fall quickly from early 1998. The trend in the 'weekly' estimates was subsequently followed by the 'monthly' estimates. However, the weekly estimates rose sharply from early 2003, and sharply from the end of 2003, coinciding with the 'bubble' observations dropping out of the sample set, as discussed above. If this trend is followed by the 'monthly' estimates, it follows that the current 'monthly' estimates would materially understate the expected (future) beta for a regulated Australian utility.

US Evidence

Table 10.3 shows the latest estimates of betas for the US comparable entities that are still listed for both the 60 weeks of weekly observations, and 60 months (five years) of monthly observations.

Table 10.3: Recent Beta Estimates: Us Proxy Group

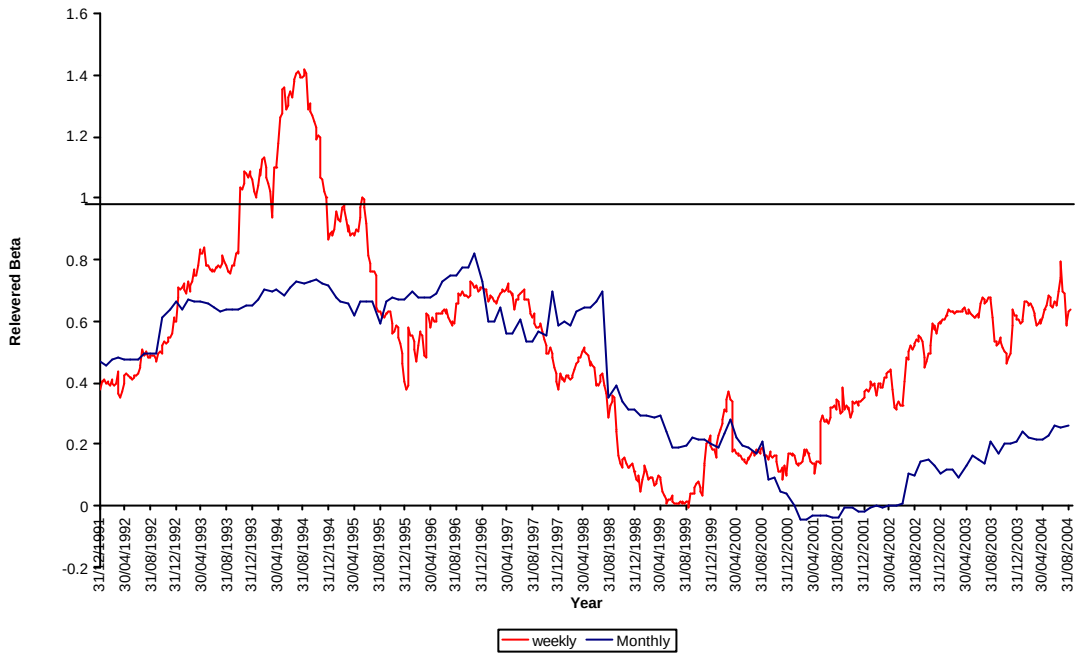
	WEEKLY OBSERVATIONS			MONTHLY OBSERVATIONS		
	BETA	GEARING	RE-LEVERED BETA	BETA	GEARING	RE-LEVERED BETA
CENTREPOINT ENERGY	0.82	78%	0.45	0.71	65%	0.61
CLESCO CORPORATION	0.97	53%	1.14	0.74	50%	0.93
DTE ENERGY CORPORATION	0.30	57%	0.33	0.03	55%	0.03
EMPIRE DISTRICT ELECTRIC COMPANY	0.61	46%	0.81	0.01	48%	0.01
EL PASO ELECTRIC CORPORATION	0.84	49%	1.07	0.01	53%	0.02
ENTERGY CORPORATION	0.50	40%	0.74	-0.03	48%	-0.04
ELEXON CORPORATION	0.26	42%	0.37	0.06	43%	0.08
FIRSTENERGY CORPORATION	0.39	51%	0.47	0.06	55%	0.07
FPL GROUP	0.30	45%	0.42	0.20	39%	0.30
MGE ENERGY	1.01	30%	1.76	0.17	27%	0.30
PROGRESS ENERGY	0.43	50%	0.54	0.17	50%	0.22
WESTAR ENERGY	0.51	62%	0.49	0.79	71%	0.57
AVERAGE	**0.58**	**50%**	**0.72**	**0.24**	**50%**	**0.26**

Source: ACG analysis, data obtained from Bloomberg. The 'weekly sampling' comprises 60 weeks of observations, and the 'monthly sampling' comprises 60 months of observations.

The pattern in the US estimates is very similar to that observed in Australia. The 'weekly' beta estimate for every firm is higher than the 'monthly' estimate, and the average of the group using the weekly estimates is also substantially higher than the past. The estimate of the beta that is obtained using the 'weekly' methodology is 0.72, which is very similar to the average of the beta estimate for the Australian comparable entities.

Figure 10.3 shows the same 'rolling' beta estimates for the US firms as shown above for the Australian firms (that is, the rolling estimates over the period since the start of 1992 for both the 'weekly' and 'monthly' beta estimates).

Figure 10.3: USA – Average Across The Proxy Group



Source: ACG analysis, data obtained from Bloomberg. The 'weekly' line is weekly sampling and 60 weeks of observations, and the 'monthly' line is monthly sampling and 60 months of observations.

Of interest in this figure is the reasonably constant average of the 'monthly' betas for the proxy group between about 0.6 and 0.8 before the start of 1998, and then a substantial decline in the 'weekly' estimates followed by the 'monthly' estimates, with this decline following a similar pattern to that observed in Australia. The weekly beta estimates have since risen to levels that are more consistent with the pre 1998 period. However, whilst the monthly beta estimates have risen, the rate of increase is slower rate than the rate of increase observed in the weekly estimates. As with Australia, if the trend in 'weekly' estimates is followed by the 'monthly' estimates, the current 'monthly' estimates would materially understate the expected (future) beta for US electricity distributors.

Given this evidence the Commission considers that although it cannot be absolutely certain that the technological "boom and burst" has had a material impact on observed betas, there is evidence that it may have caused a short term aberration.

10.6.6 Other Regulators' Decisions

An important issue requiring consideration is the decisions by other jurisdictional regulators. Table 10.4 provides recent decisions made by Regulators.

Table 10.4: Proxy Equity Beta used by Australian Regulators in Relevant Decisions

INDUSTRY	YEAR	PROXY EQUITY BETA (60% D/A)
Electricity Distribution		
NSW Distributors	IPART, 2004	0.78 – 1.11
ActewAGL	ICRC, 2004	0.90
Aurora (Tas)	OTTER, 2003	0.95
Queensland Distributors	QCA, 2001	0.71
Victorian Distributors *	Victorian ESC, 2000	1.00
ETSA Utilities * , **	SA Govt, 1999	0.83 – 1.20
Electricity Transmission		
Transend	ACCC, 2003	1.00
Murraylink *	ACCC, 2003	1.00
ElectraNet *	ACCC, 2002	1.00
SPI PowerNet *	ACCC, 2002	1.00
Powerlink	ACCC, 2001	1.00
Gas Distribution		
Victorian Distributors	Victorian ESC, 2002	1.00
Envestra * / Allgas	QCA, 2001	0.97
AGL *	IPART, 2000	0.90 – 1.10
Albury Gas Company	IPART, 1999	0.90 – 1.10
AlintaGas *	OFFGAR, 2000	1.08
Great Southern Networks	IPART, 1999	0.96 – 1.10
Gas Transmission		
Moomba to Sydney Pipeline *	ACCC, 2003	1.00
GasNet *	ACCC, 2002	0.98
Moomba to Adelaide Pipeline *	ACCC, 2001	1.16

Source: Essential Services Commission, October 2002, Review of Gas Access Arrangements – Final Decision, p.138; Queensland Competition Authority, May 2001, Final Determination – Regulation of Electricity Distribution, p.98; Office of the Regulator General, September 2000, Final Decision – Electricity Distribution Price Determination 2001-05 Volume I Statement of Purpose and Reasons, p.120; Independent Pricing & Regulatory Tribunal, December 1999, Final Determination – Regulation of NSW Electricity Distribution Networks, p.45; Queensland Competition Authority, October 2001, Final Decision – Proposed Access Arrangements for Gas Distribution Networks, Allgas Energy Limited & Envestra Limited, page 231; Independent Pricing & Regulatory Tribunal, June 2000, Final Decision – Access Arrangement for AGL Networks Limited, p.64; Independent Pricing & Regulatory Tribunal, December 1999, Final Decision – Access Arrangement for Albury Gas Company Limited, p.6; Office of Gas Access Regulation, June 2000, Final Decision – Access Arrangements for Mid-West and South-West Gas Distribution System, Alinta Gas, Part a-17; Independent Pricing & Regulatory Tribunal, March 1999, Final Decision – Great Southern Energy Gas Networks Pty Ltd, p.24; Office of the Regulator General, October 1998, Access Arrangements – Multinet Energy Pty Ltd, Westar Gas Pty Ltd, Stratus Gas Pty Ltd – Final Decision, p.10 ACCC, 2001, Queensland Transmission Revenue Cap 2002-2006/07, November, p.28; ACCC, 2002, South Australian Transmission Network Revenue Cap 2003 – 2007/08, December, p.41; ACCC, 2002, Victorian Transmission Revenue Caps 2003-2008, December, p.33; ACCC, 2002, Final Decision – GasNet Australia Access Arrangement Revisions, November, p.112; ACCC, 2001, Access Arrangement for the Moomba to Adelaide Pipeline – Final Decision, September, p.53; ACCC, Access Arrangement for Transmission Pipelines Australia – Final Decision, October, p.62; Independent Pricing & Regulatory Tribunal, June 2004, Final Decision – Regulation of NSW Electricity Distribution Networks, p.45

* These observations relate to private firms, and so are also clause 7.2(k) benchmarks.

** The SA Govt used a range for gearing levels of between 50 per cent and 60 per cent.

The Commission considers that recent decisions of other regulators provide insight into the parameters consistent with prevailing market conditions for the relevant

regulated entities. The Commission also notes that the decisions marked by an asterisk reflect privately owned firms (or firms which, at the time, were expected to become private shortly) and thus are also benchmarks for private sector firms as contemplated by clause 7.2(c) of the EPO.

Lastly, the Commission notes ETSA Utilities' view that it deserves a higher return than reflected in these benchmarks due to its reliance on revenue from rural areas.

The Commission notes that the Victorian ESC, in its last review of the price controls applied to the Victorian electricity distribution businesses, examined in detail the question as to whether the required return for predominantly rural electricity distributors was likely to exceed that of predominantly urban distributors. It concluded that while the cost of serving rural areas is higher (and which is reflected in a higher regulatory asset base and higher expenditure forecasts), the additional volatility in earnings from serving rural areas is more likely to reflect diversifiable risk, which does not require a higher return. As a result, the Victorian ESC adopted the same cost of capital assumption for all distributors, and its decision on this matter was upheld on appeal.

As discussed in section 10.3, an additional margin is only required if the additional risk associated with serving rural areas is non-diversifiable risk. The Commission is of the view that it is incorrect to suggest that if compensation for a type of risk is not reflected in the beta factor (ie is a diversifiable risk) then an allowance elsewhere is required. Rather, if a particular type of risk is diversifiable, then no allowance is required – neither in the beta nor in the cash flows. Thus, the Commission has not been convinced that the cost of capital associated with a rural operation would be higher.

For the purposes of setting regulated charges for the period between July 2005 and June 2010, the Commission has had regard to the latest market evidence on equity betas. However, given its concerns about the quality of current market data, the Commission also considers that the estimates adopted by other regulators provide further evidence about current market requirements and should also be taken into account. The latest market evidence would suggest an equity beta (for gearing of 60 per cent debt-to assets) of less than 1.0, if regard is had to the estimates that are obtained at the end of each quarter over the period since September 1999. In contrast, as discussed above, regulators have adopted a range of between about 0.7 and 1.2, with many adopting 1 (or approximately 1). The Commission considers that a value that is within the range adopted by regulators is appropriate, but also considers it appropriate to place weight on the market evidence of betas.

In reaching its decision, the Commission considered the balance between the statistical uncertainties associated with the data on historical betas and the evidence of declining trend in beta estimates.

For these reasons, the Commission proposes to adopt an equity beta of 0.8 for a gearing level of 60 per cent debt-to-assets. This is at the upper end of observed equity betas, however measured, over the past 4 years.

10.6.7 Market Risk Premium (MRP)

The market risk premium (also referred to as the 'equity premium'), as measured and applied in practice, is the premium above the risk free rate of return that investors expect to earn on a well-diversified portfolio of equities.

Determining the exact magnitude of the MRP is a controversial issue in financial economics. While the MRP should be a forward-looking measure, a common approach has been to use the measured historical premium as an estimator of the forward-looking premium.

However, a number of methodological issues need to be considered with the use of the historical equity premium as a forecast of the future premium. For example, the appropriate length of the historical time period is a key variable in determining the MRP. The use of an average of share market returns over the very long periods required to obtain any precision in the estimates (but which remain imprecise) has been criticised as including evidence from a period that is irrelevant. A number of potential biases in historical estimates have also been suggested – such as a systematic under-expectation of inflation and capital gains over the 20th century.

The Commission's view is that all the methodologies used to estimate the MRP deliver estimates that have a large degree of statistical error. In view of this, it considers that the best estimate of the MRP will come from having regard to the results of each of the different methodologies (tempered by an understanding of the strengths and weaknesses of each methodology) rather than placing sole weight on any single methodology. It considers that such an approach will lead to an estimated MRP that best meets prevailing market conditions.

One of the common methodologies used to determine the MRP is the use of historical information on the returns to stocks and bonds.

A commonly cited study on MRP was undertaken by Professor Officer.[134] The results of this work – updated by the author to the end of 2001 – are replicated in Table 10.5.

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[134] Officer, R., 'Rates of Return to shares, bond yields and inflation rates: An historical perspective', in *Share Markets and Portfolio Theory: Readings and Australian Evidence*, 2nd edition, University of Queensland Press, 1992.

Table 10.5: Historical Australian Market Risk Premium – 1882 to 2001

TIME PERIOD	AVERAGE EQUITY RISK PREMIUM	STANDARD DEVIATION	STANDARD ERROR OF THE MEAN
1882-2001	7.19%	16.97%	1.55%
Different Ending Point:			
1882-1950	8.00%	11.11%	1.34%
1882-1970	8.16%	13.70%	1.45%
1882-1990	7.40%	17.33%	1.66%
Different Beginning Point:			
1900-2001	7.14%	17.94%	1.78%
1950-2001	6.51%	22.60%	3.13%
1970-2001	3.37%	24.38%	4.31%

Source: ESC Gas Final October 2002

This shows that the average over the longest period was around 7.2 per cent, or 7.3 per cent if the non-cash value of franking credits for the period since 1987 are included.[135] However, this is the point estimate of the expected premium, which is subject to statistical uncertainty. The 95 per cent confidence interval for the expected premium obtained from historical returns over the period between 1882 and 2001 is 4.3 per cent to 10.4 per cent. Most of the studies on market risk premiums just present the average of historical returns, and only differ in their results because of the periods considered or the form of average adopted.

However, due to the statistical imprecision and the fact that historical information is being used to forecast the premium, the Commission treats the estimate of the market risk premium from historical data with some caution.

First, even if the whole period from 1882 is used, the statistical precision is low.

Secondly, it can be questioned whether data going back to the turn of the last century remain relevant – a number of arguments have been advanced that suggest the premium may have fallen over this period. Chief amongst these are that it has become much easier and cheaper for individuals to diversify their portfolios, and also that the time horizon of investors may have lengthened as the use of stocks to provide for retirement increases.

The latter of these arguments may suggest that it would be better to rely upon the average of the outturn equity premium during a more recent period – during the period since 1970 the premium has been under 4 per cent. However, the statistical precision reduces with the length of the sample period. The use of a sample period starting in 1970 results in a 95 per cent confidence interval for the premium of

[135] This is consistent with an assumption for gamma of 0.5 (and a value for franking credits once distributed of 0.6).

approximately 4 per cent plus-or-minus 9 percentage points (that is, between -5 per cent and +13 per cent).

Lastly, it has also been argued that the historical equity premium may have been biased upwards because of systematic underestimation of inflation (and so downward biased nominal bond yields) and underestimation of capital gains. The implication of this argument is that the actual premium to equities (over bonds) that we have observed may have been higher than what investors expected over the relevant historical period – and it is the *expectation* of the premium to equities (not the *actual* premium) that is the relevant parameter.

The Victorian ESC considered at length the results of a number of studies that presented alternative methodologies for estimating the equity premium that investors historically expected, with these different methodologies designed to overcome the possibility that investors in the past may have under-forecast capital gains.

The studies note that the expected equity premium can be expressed as the sum of the expected dividend yield and the expected capital gain. Rather than use the actual capital gain as an estimate of the expected capital gain, the studies employ alternative proxies for expected capital gains – such as actual dividends and earnings growth, and actual GNP growth. The results that were reported by the Victorian ESC showed the alternative estimates of the historically-expected equity premium to be consistently lower than the average of the historical premium to equity, although no such study is understood to have been undertaken in Australia.

Finally, the Commission notes that a market risk premium of 6 per cent has almost universally been adopted by Australian energy regulators for electricity distribution and transmission businesses, as shown in Table 10.6, with some regulators adopting a range that extends below this.

As discussed previously, these decisions provide an additional source of evidence as to the value of the MRP that is consistent with prevailing market conditions. The decisions marked with an asterisk are also benchmarks within the meaning of clause 7.2(k)(ii) of the EPO (reflecting those decisions that related to privately owned firms). The conclusion that can be drawn from this subset of the decisions is not materially different to the conclusions that can be drawn from the complete set of decisions.

Having considered all of these pieces of evidence, the Commission considers that a MRP of 6 per cent is most consistent with the value that reflects the prevailing market conditions for investments which have a similar nature and degree of business risk as those faced by ETSA Utilities. Accordingly, the Commission will adopt a market risk premium of 6 per cent in its calculation of the regulatory rate of return.

Table 10.6: Market Risk Premium Assumptions used by Australian Regulators in Relevant Decisions

INDUSTRY	YEAR	MARKET RISK PREMIUM
Electricity Distribution		
New South Wales Distributors	IPART, 2004	5% - 6%
ActewAGL	ICRC, 2004	6%
Aurora	OTTER, 2003	6%
Queensland Distributors	QCA, 2001	6%
Victoria Distributors *	ESC, 2000	6%
ETSA Utilities *	SA Govt, 1999	6% - 7%
Electricity Transmission		
Transend	ACCC, 2003	6%
Murraylink *	ACCC, 2003	6%
ElectraNet *	ACCC, 2002	6%
SPI PowerNet *	ACCC, 2002	6%
Powerlink	ACCC, 2001	6%
Gas Distribution		
Victorian Distributors *	ESC, 2002	6%
Envestra * / Allgas	QCA, 2001	6%
AGL *	IPART, 2000	5% – 6%
Albury Gas Company	IPART, 1999	5% – 6%
AlintaGas *	OFFGAR, 2000	6%
Great Southern Networks	IPART, 1999	5% – 6%
Gas Transmission		
Moomba to Sydney Pipeline *	ACCC, 2003	6%
GasNet *	ACCC, 2002	6%
Moomba to Adelaide Pipeline *	ACCC, 2001	6%

Source: Essential Services Commission, October 2002, Review of Gas Access Arrangements – Final Decision, p.138; Queensland Competition Authority, May 2001, Final Determination – Regulation of Electricity Distribution, p.98; Office of the Regulator General, September 2000, Final Decision – Electricity Distribution Price Determination 2001-05 Volume I Statement of Purpose and Reasons, p.120; Independent Pricing & Regulatory Tribunal, December 1999, Final Determination – Regulation of NSW Electricity Distribution Networks, p.45; Queensland Competition Authority, October 2001, Final Decision – Proposed Access Arrangements for Gas Distribution Networks, Allgas Energy Limited & Envestra Limited, page 231; Independent Pricing & Regulatory Tribunal, June 2000, Final Decision – Access Arrangement for AGL Networks Limited, p.64; Independent Pricing & Regulatory Tribunal, December 1999, Final Decision – Access Arrangement for Albury Gas Company Limited, p.6; Office of Gas Access Regulation, June 2000, Final Decision – Access Arrangements for Mid-West and South-West Gas Distribution System, Alinta Gas, Part a-17; Independent Pricing & Regulatory Tribunal, March 1999, Final Decision – Great Southern Energy Gas Networks Pty Ltd, p.24; Office of the Regulator General, October 1998, Access Arrangements – Multinet Energy Pty Ltd, Westar Gas Pty Ltd, Stratus Gas Pty Ltd – Final Decision, p.10; ACCC, 2001, Queensland Transmission Revenue Cap 2002-2006/07, November, p.28; ACCC, 2002, South Australian Transmission Network Revenue Cap 2003 – 2007/08, December, p.41; ACCC, 2002, Victorian Transmission Revenue Caps 2003-2008, December, p.33; ACCC, 2002, Final Decision – GasNet Australia Access Arrangement Revisions, November, p.112; ACCC, 2001, Access Arrangement for the Moomba to Adelaide Pipeline – Final Decision, September, p.53; ACCC, Access Arrangement for Transmission Pipelines Australia – Final Decision, October, p.62.

* These decisions relate to privately owned firms, and so are clause 7.2(k) benchmarks.

10.6.8 Capital Structure and the Cost of Debt

There are four key issues to address in determining the capital structure and the debt premium. These are:

- the appropriate gearing ratio that should be assumed for ETSA Utilities, including the appropriate period for the term to maturity;
- whether the various additions to the prevailing yield on similarly rated bonds should be included, namely a premium to reflect the likely market pressure from a large issue, a premium to reflect the cost of hedging against inflation risk, and a premium for the cost of forward hedging;
- the appropriate source for obtaining an estimate of the cost of borrowing for an entity consistent with the benchmark assumptions; and
- the appropriate allowance for the cost of establishing debt facilities.

These issues will be addressed in turn.

Characteristics of the Benchmark Entity

The methodology for estimating the cost of capital associated with ETSA Utilities' regulated activities requires an assumption about the capital structure of those activities. It is standard practice amongst Australian regulators to adopt a benchmark assumption based upon observed practice to avoid providing perverse incentives over financing decisions.

The use of benchmark assumptions ensures that regulated entities have incentives to adopt (and benefit from) more efficient financing arrangements, as well as protecting consumers from inefficient financing decisions. The use of benchmark assumptions also permits regulators to make high-level assumptions about financing matters, and to avoid the need to form views upon the merits of the complex financing arrangements that are commonplace in modern utilities.

The Commission is of the view that the decisions adopted by Australian regulators best reflects the prevailing conditions in the market for investments which have a similar nature and degree of business risks as those faced by ETSA Utilities.

The assumptions adopted by Australian electricity regulators in recent decisions are set out in Table 10.7.

Table 10.7: Australian Regulators' Assumptions about Benchmark Financing Arrangements

ENTITY	REGULATOR (DATE)	GEARING (D/A)	TERM (YEARS)	CREDIT RATING
Electricity Distribution				
Qld Distributors	QCA (May 2001)	60%	10	BBB+
Victorian Distributors	ESC (Sep 2000)	60%	10	BBB to A
Gas Distribution				
Victorian Distributors	ESC (Oct 2002)	60%	10	BBB+
Qld Distributors	QCA (Oct 2001)	60%	10	BBB+
Electricity Transmission				
ElectraNet (SA)	ACCC (Dec 2002)	60%	5.5	A
SPI PowerNet (Vic)	ACCC (Dec 2002)	60%	5	A
Gas Transmission				
GasNet	ACCC Nov 2002)	60%	5	BBB+

QCA, 2001, Final Determination – Regulation of Electricity Distribution, May, pp.85-86; Office of the Regulator-General, 2000, Electricity Distribution Price Determination 2001-05, September, Vol 1, p.298; Essential Services Commission, 2002, Review of Gas Access Arrangements – Final Decision, October, p.141; QCA, 2001, Final Decision on Proposed Access Arrangements for Allgas and Envestra, October, pp.219-222; ACCC, 2002, South Australian Transmission Network Revenue Cap 2003 – 2007/08, December, pp.22-27; ACCC, 2002, Victorian Transmission Revenue Caps 2003-2008, December, p19; ACCC, 2002, Final Decision – GasNet Australia Access Arrangement Revisions, November, pp.89-95, 141-149.

While the ACCC has assumed the same capital structure for electricity transmission, it has assumed that this would be consistent with a higher credit rating (A). The Commission notes the difference between the form of regulation for transmission entities and that for ETSA Utilities; whilst, transmission is regulated by way of a revenue cap ETSA Utilities is regulated by way of revenue yield.

Gearing levels (within a reasonable band, and making certain assumptions) do not necessarily have any impact on ETSA Utilities' cost of capital. This is because increasing debt (with lower cost of capital) will increase the cost of equity (which has the higher cost of capital) thus offsetting any reduction in the weighted average cost of capital. In the absence of taxation effects or other market imperfections, the WACC would remain constant, and even in the presence of these factors, would be likely to be of second-order significance across a reasonable range of gearing levels, particularly given the Commission's assumption about the value of imputation tax credits.[136]

With regard to assumed credit rating, it should be noted that the issue is not the reasonableness of assumed credit rating in isolation, but whether the credit rating assumed is consistent with the assumed gearing level.

[136] Whether – and to what extent – gearing levels affect the WACC is a much debated issue in the finance field. The potential means through which higher gearing could affect the WACC (and the sign of the effect) include: tax effects (+); expected bankruptcy costs (-); loss of financial flexibility (-); and discipline on decisions or signalling effects (+). The Commission's assumption of a gamma value of 0.5 is consistent with an assumption that the tax benefits from higher gearing are likely to be small.

The two measures of the gearing levels and credit ratings of a sample of privately-owned Australian utilities are set out in Table 10.8.

Table 10.8: Gearing Levels and Credit Ratings for Australian Utilities

ENTITY	CREDIT RATING	DATE	GEARING (D/A)	GEARING (D/REG VALUE)
Envestra	BBB	Dec 2002	72.5%	103.5%
GasNet	BBB	Dec 2002	69.8%	121.2%
ETSA Utilities	A-	Dec 2002	63.5%	87.4%
CitiPower Trust	A-	Dec 2002	20.6%	36.1%
Powercor	A-	Dec 2002	39.7%	78.7%
ElectraNet	BBB+	Dec 2002	72.6%	92.5%
SPI PowerNet	A+	Dec 2002	79.8%	88.7%

Credit ratings were taken from: Standard and Poors, 2003, Utilities Report Card, October. Gearing levels for companies except for Envestra and GasNet reflect debt-to-total capital (as reported in: Standard and Poors, op cit). Gearing levels for Envestra and GasNet have been calculated as the ratio of the market value of equity and the sum of the market value of equity and book value of debt using share price data. Regulatory asset bases are estimates from published regulatory decisions for all companies except for ETSA Utilities, for which the value recorded in its regulatory accounts has been used.

With the exception of the CitiPower Trust and Powercor, the measured gearing level for all of the regulated entities is higher than the regulatory benchmark – particularly when measured as a proportion of the regulatory value. The Commission notes that the measure of gearing measured as a proportion of the asset's regulatory value has some relevance when setting price caps because it shows the stock of debt – and hence the available interest deductions – that regulated entities are actually able to maintain. These observations suggest that an efficiently run distribution businesses with a level of debt that is equal to 60 per cent of its regulatory value would be expected to maintain at least a BBB+ credit rating.

Within this context, the recent decision by the Australian Competition Tribunal to overturn the ACCC's use of a BBB+ rating to estimate the cost of capital for the Moomba to Sydney pipeline, is also considered.[137] The reason for the Tribunal's decision was that whilst the ACCC stated that it had decided on the use of a BBB+ rating, because it reflected the industry standard for the pipeline industry, the evidence considered by the ACCC pointed to the industry standard as being BBB.

The Commission considers that the Tribunal's findings have limited relevance to this case. As pointed out above, the correct question is not "what is the industry standard credit rating?", but rather, "what credit rating would be consistent with the assumed gearing level?". As noted above, the Commission considers that given the level of gearing of the entities and their actual ratings (especially when

[137] Application by East Australia Pipeline Limited [2004] ACompT 8 (8 July 2004).

gearing is measured as a proportion of regulatory value) the BBB+ rating is already conservative.

However, the Commission also notes that the consultant report quoted by the Tribunal stated that the most appropriate approach to determining the benchmark credit rating would be to determine the financial ratios (such as interest cover) that are implied by the regulatory decision,[138] and presumably compare those ratios to the target bands issued by ratings agencies as well as the financial ratios of listed Australian utilities. The Commission notes that gearing level is an indicator that ratings agencies commonly use when assigning credit ratings – and that gearing expressed as a proportion of regulatory value is now a common measure of gearing by ratings agencies – but that an examination of other financial ratios will offer a broader view of the financial health of an entity that is financed in a manner consistent with the benchmark assumptions. The Commission intends to undertake such financial modelling prior to issuing its Draft Determination to confirm that the assumption of a BBB+ credit rating is appropriate.

Derivation of the Benchmark Debt Premium

In addition to the cost of debt premiums, a number of other costs associated with borrowing are also considered in the total cost of borrowing. These relate to the allowance for the cost of entering into a number of different types of hedges and for market imperfections, more specifically:

- an allowance for hedging against inflation risk;
- an allowance for the cost of forward hedging, which is a consequence of the requirement under the Reset Schedule for a five year average of interest rates to be used when determining the regulatory rate of return; and
- an allowance for the fact that if ETSA Utilities refinanced all of its debt on the one day in the Australian corporate bond market, that it would 'pressure the market' (ie push up yields).

The first and last of these are factors or allowances that can be considered relevant to other regulated utilities, so that the logic in decisions adopted by other regulators should be equally applicable to ETSA Utilities (provided that logic is sound) and the decisions adopted provide evidence as to the market requirements. In contrast, the second of these factors is a factor that relates to ETSA Utilities uniquely, so that decisions of other regulators are not relevant.

Turning to the issue of hedging and other allowances generally, the Commission notes that a reasonably standard approach to determining benchmark financing costs has developed in respect of regulated distribution businesses. The Commission is not aware of the inclusion of an allowance for such matters. It

[138] Application by East Australia Pipeline Limited [2004] ACompT 8 (8 July 2004), para 63.

notes that the Victorian ESC has considered the issue of hedges and the setting of regulated prices at length,[139] and (in essence) has made two observations about the potential for a misestimate of the cost of capital if hedging costs are recognised. These observations were as follows:

- *Compensation for risk* – the consequence of not being 'hedged' against a particular source of risk is that the risk is borne by the provider. However, the fact that the risk is borne by the provider does not imply that compensation is required. In particular, no compensation for risk is required where the risk is diversifiable. Secondly, even if the risk is non-diversifiable, if the form of risk borne by the entity in question is also borne by the firms that are used to derive the beta estimate, then compensation for that risk is already provided through the beta. In this situation, including hedging costs would lead to the estimate of the cost of capital not reflecting 'prevailing conditions in the market for investments having a similar nature and degree of business risk as those faced by ETSA Utilities'.
- *Inconsistency across benchmarks* – even if hedging is possible and undertaken by the regulated entity, it may be inappropriate merely to add in the cost of entering into those arrangements. Companies in competitive markets do enter into hedging arrangements – but only do so if there are benefits from hedging that outweigh the costs. Therefore, if only the cost of hedging arrangements were taken into account – but none of the benefits – then there would be a counter-intuitive impact on prices (ie regulated prices would *rise*, whereas a greater recognition of efficient hedging opportunities should imply that regulated prices fall). The important issue is to ensure that if hedging costs are recognised then the benefits should also be identified, or both costs and benefits should be ignored. Again, failing to include benefits and costs, or excluding both, would lead to the estimate of the cost of capital not reflecting 'prevailing conditions in the market for investments having a similar nature and degree of business risk as those faced by ETSA Utilities'.

The specific issue of hedging against inflation risk was debated at length in the Victorian ESC electricity distribution price review in 2000. The Victorian ESC rejected the proposal to include the cost of inflation hedging, on the grounds that if the risk was diversifiable, then compensation was unnecessary, and if it was non-diversifiable, then it would be reflected in the empirical estimate of the equity beta. The Victorian ESC's findings reflected the fact that inflation hedging is not widespread, and so the non-diversifiable component of the risk would be reflected in its beta estimates. Implicitly, the fact that this type of hedging is not widespread implies that its financing benchmarks (ie gearing level and credit rating) would be

[139] ESC, 2001, 2003 Gas Access Arrangement Review – Further Guidance to the Distributors, December.

consistent with an unhedged entity. These findings were upheld in an appeal against the decision.[140]

The Commission is of the view that the Victorian ESC's reasons are equally valid for ETSA Utilities. The Commission considers that, for the same reasons as outlined in the Victorian ESC determination, to allow a premium for inflation hedging would imply that the cost of capital estimate would not reflect 'prevailing conditions in the market for investments having a similar nature and degree of business risk as those faced by ETSA Utilities', and so should not be included in the debt margin.

Another issue relates to the premium for the risk that is not faced by other distributors, which is the risk of not being able to easily adopt a debt portfolio that reflects the assumptions reflected in the regulator's estimate of the cost of capital. In particular, ETSA Utilities has argued that:

- prudent financial management requires it to match its interest costs with the debt component of the regulatory rate of return; and
- because of the Reset Schedule (in particular, the requirement to use a five-year average of bond rates for the risk free rate) this requires progressive hedging on a forward basis throughout the regulatory period; and
- ETSA Utilities actually has forward hedged its debt to minimise the impact of interest rate variability, and has provided information to the Commission as to the hedges that it has entered into and the cost of those hedges. ETSA Utilities has proposed that its own cost of entering into the hedges (as a proportion of the principal) should form the basis of the hedging allowance, which was 18.25 basis points.

From the discussion above, notwithstanding that ETSA Utilities' situation is unique, there are a number of reasons that may suggest that it would be inappropriate to include the allowance it has proposed.

First, if ETSA Utilities did not hedge this risk but rather bore the risk, additional compensation would only be justified to the extent that it comprised non-diversifiable risk, which may not be the case.

Secondly, the Commission considers that the adoption of a benchmark financing structure of 60 per cent debt to assets and a BBB+ rating already errs in ETSA Utilities' favour.

Thirdly, ETSA Utilities' hedging strategy may deliver benefits that have not been properly taken into account. By way of example, ETSA Utilities' actual stock of debt exceeds by a substantial margin that assumed for regulatory purposes, but

[140] Office of the Regulator-General, 2000, Electricity Distribution Price Determination 2001-05, September, Vol 1, pp.293-297.

notwithstanding, it is able to maintain a higher rating than assumed by the Commission (A- rather than BBB+).

Fourthly, and related to the previous point, the hedges that ETSA Utilities has entered do not actually achieve with precision the objective that it has stated of aligning its actual cost of debt with the cost of debt assumed in the regulatory rate of return. Rather, the hedges that it has entered into fix its cost of debt for (approximately) the 2005-2010 regulatory period with reference to forward interest rates that prevailed at the date it entered into the hedges. Accordingly, there are doubts as to whether its hedging strategy reflects the unique features of the regulatory regime for the current review.

Notwithstanding its reservations, the Commission notes that ETSA Utilities has already undertaken the hedging. Moreover, the Commission accepts that ETSA Utilities is in a unique situation, due to the requirements under the Reset Schedule of the EPO. The Commission notes that much of the argument associated with the treatment of hedges relies on an assumption of consistency with other regulated businesses, and that the methodology which must be used to determine the risk free rate for ETSA Utilities is unique in Australia. Given these reasons, the Commission is mindful that not allowing a premium for this hedging strategy would leave ETSA Utilities without the ability to recover the costs.

However, as the Reset Schedule will cease to apply after the current review, the allowance of this premium will be reviewed at future reviews (including reviews of other utilities that are undertaken by the Commission).

Lastly, as noted above, the final premium to the benchmark cost of debt relates to a margin which takes account of the fact that if ETSA Utilities were to raise all of its debt on the Australian corporate bond market as a single issue, it would pressure market capacity.

The Commission is not convinced that such an allowance is appropriate. The standard regulatory practice for deriving a benchmark cost of debt is to use Australian corporate bond yields to provide a proxy for borrowing costs, which reflects the fact that the use of traded bonds on the Australian market provides for a transparent method of deriving the cost of debt. However, the use of these yields does not imply an assumption that Australian utilities will finance all of their debt from this market. Rather, all that is required is that the yield on Australian corporate bonds provides an unbiased estimate of the cost of raising funds across the full range of funding sources available to Australian utilities.[141]

The Commission would not expect ETSA Utilities actually to raise all of its debt on one day from any of the potential funding sources, but rather that it would seek to

[141] The other debt finance options include: issuing 'wrapped' debt (that is, debt whose repayment is guaranteed by an insurer and which is then issued at a higher credit rating where the available pool of funds is deeper); issuing debt on the US or other foreign corporate bond markets; issuing privately placed debt, either in Australia or overseas; and raising finance from banks.

raise debt when and where it was cheapest, subject to prudent risk management constraints. No evidence has been presented that the use of the yield on Australian corporate bonds systematically understates the cost of debt raising across the full range of funding options, either from ETSA Utilities or – to the Commission's knowledge – in other matters before another Australian energy regulator.

Source of Information on Corporate Bonds

ETSA Utilities have also suggested that the CBASpectrum service should not be used to derive a proxy for the current yield on Australian corporate bonds with a defined term and credit rating. It expressed the view that 'benchmark' services such as the CBASpectrum service includes firms that are not valid comparisons for ETSA Utilities and commented that utility issuers consistently price wider than an equivalently rated corporate bond. It proposed the use of a smaller sample of corporate bond issuances, which were energy market firms.

The Commission notes that the CBASpectrum service has been used by a number of other regulators, including the ACCC in its recent decisions on ElectraNet, SPI PowerNet and GasNet as well as the Victorian ESC's recent gas distribution price review. None of the regulators in those matters have been presented with evidence that suggested the CBASpectrum bond yields systematically understated the predicted cost of debt raising for a utility firm. Indeed, the Victorian ESC noted that the CBASpectrum yields aligned closely with the views of market practitioners on the cost of debt for utility firms.[142]

In light of the established regulatory practice of using the CBASpectrum service to generate proxy yields for the purpose of deriving benchmark financing arrangements, as well as the additional transparency this entails, and an absence of strong evidence that this service will understate the cost of debt finance, the Commission intends to adopt this service for the current matter. The Commission will derive a debt premium by averaging corporate bond yields over the same period as the risk free rate. As the Commission has used average Government bond yield taken from the period 14 February 2000 to 27 October 2004, and the rates kept constant from thereon until 11 February 2005 to derive the risk free rate for the purpose of this determination, it has taken the CBASpectrum yield in excess of bonds over the same period, which implies a debt premium of 1.33 per cent.

The Commission will update this debt premium in line with its updated risk free rate, as discussed in section 10.4.

[142] Essential Services Commission, 2002, Review of Gas Access Arrangements – Final Decision, October, p.366.

Debt Establishment Costs and Equity Raising Costs

ETSA Utilities has sought an allowance in its debt to cover the cost of raising debt finance of 12.5 basis points. The Commission notes that this allowance is consistent with allowances the ACCC has made in cases where it assumed BBB+ rated debt, and hence adopts ETSA Utilities' proposal.

In contrast, the Commission is not convinced that an additional allowance in respect of the cost of raising equity is warranted. Whilst the ACCC has permitted such an allowance in its three most recent decisions (namely, in respect of GasNet, ElectraNet and SPI PowerNet), the same issue was considered and rejected by the Victorian ESC.[143]

In assessing the issue, the Victorian ESC noted that whereas debt finance is typically rolled-over periodically (with new transaction costs incurred), once equity has been raised, it is perpetual. It further noted that the assets in place at the time of privatisation had been financed over the previous decades, and any cost associated with their financing should have been assumed to be reflected in the regulatory asset bases set prior to privatisation. It further noted that transaction costs in relation to future capital expenditure would only be incurred where new equity injections are required – no transaction costs are incurred where projects are financed from retained earnings. It considered it unlikely that new equity injections would be required for new capital expenditure under the assumed benchmark financing arrangements.

The Commission accepts the arguments summarised above from the Victorian ESC as better representing prevailing market conditions. In addition, it is noted that the inclusion of a cost of raising equity in respect of the assets at place as at 1 July 1999 could be interpreted as a revaluation of those assets, which is precluded in relation to the fixed assets under clause 7.2(e) of the EPO.

For the purpose of deriving its benchmark assumption about the financing structure of ETSA Utilities' regulated activities, the Commission proposes to adopt the following assumptions or approaches:

- a capital structure of 60 per cent debt-to-assets;
- BBB+ credit rating and debt with a term of 10 years;
- use Australian corporate bond yields as predicted by the CBASpectrum service to derive a benchmark debt premium (with yields consistent with the benchmark term and credit rating);
- use the average yield over the same period as the risk free rate;
- add an allowance for debt establishment costs of 12.5 basis points;
- add an allowance for timing hedging of 18.25 basis points; and

[143] Essential Services Commission, 2002, Review of Gas Access Arrangements – Final Decision, October, pp.378-379.

- no allowance will be made for the cost of raising equity.

A benchmark debt premium of 1.64 per cent (including debt establishment and timing hedging costs) has been adopted in this Determination. However, this will be updated in the Final Determination, as discussed in section 10.4.

10.7 Taxation

As noted above, CAPM/WACC methodology required by the Reset Schedule generates an estimate of the after-tax cost of capital associated with an asset. As ETSA Utilities will be liable for company tax, an assumption must be made about company taxation liabilities associated with the provision of regulated services. Whilst the Reset Schedule prescribes the method through which this allowance should be calculated, ETSA Utilities has raised the issue of the treatment of the tax disadvantage associated with the handling of customer contributions.[144]

The formulae set out in the Reset Schedule require an estimate of the value of franking credits that would be generated by an efficient electricity distributor. This is discussed below.

10.7.1 Derivation of the Allowance for Taxation – Customer Contributions

The Reset Schedule requires that the allowance be calculated by using what has been known as a 'simple transformation' – this involves starting with a form of after tax WACC, and then grossing this estimate by an assumption about the rate of tax that would be payable on that definition of income.[145] The Reset Schedule prescribes both the form of after tax WACC (after tax nominal WACC) and the rate of tax assumed to be payable on that definition of income (equal to the statutory tax rate).

ETSA Utilities had previously commented that the tax treatment of customer contributions works to its disadvantage, and has proposed that it be compensated for the shortfall.[146] Under current taxation laws, customer contributions are treated as income in the year that ETSA Utilities receives the contribution; as the asset created can only be depreciated over its tax life, this leads to a tax disadvantage to ETSA Utilities (in preset value terms).

It is not clear that the Commission has the discretion to make an adjustment for the specific provision in the tax law that has been raised by ETSA Utilities, given that the treatment of taxation is prescribed in the Reset Schedule. Moreover, even if the Commission had the discretion to make such an allowance, the Commission

144 ESCOSA, Electricity Distribution Price Review: Price Review Framework, Working Conclusions, October 2002, pp.15-16

145 An allowance for taxation is not derived directly. Rather, the after tax WACC is scaled up to a pre tax form, the latter of which includes an implicit allowance for taxation.

146 ETSA Utilities' letter to the SAIIR on Electricity Distribution Price Review Framework, dated 17 September 2002

questions whether it is reasonable to make an adjustment for the specific tax disadvantage identified by ETSA Utilities without also making an adjustment for all of the cases where the tax system is more advantageous to ETSA Utilities than assumed in the prescribed 'simple transformation' method. The Commission notes that other aspects of the prescribed 'simple transformation' method are advantageous to ETSA Utilities (that is, lead to an overstatement of the amount of tax to be paid).

Accordingly, the Commission will not make any adjustments for either advantages or disadvantages that ETSA Utilities may receive or suffer as a result of the actual application of the company taxation provisions relative to the assumptions implicit in the 'forward transformation' methodology.

10.8 Implications of Dividend Imputation

Under the system of dividend imputation, Australian shareholders are able to receive a credit for any tax paid at the company level when determining their personal income tax. Foreign shareholders receive no such credit. In the previous consultation papers, it was noted that the standard practice among Australian regulators and finance practitioners has been to treat this benefit as an offset to the entity's company taxation liability. Within this methodology, the assumed value of imputation (or franking) credits created is usually expressed as a proportion of their face value, and is denoted by gamma (γ).

Like a number of the other inputs into the estimation of the cost of capital, the estimation of the gamma term has been controversial.

In particular, the measurement of the value of franking credits is subject to substantial measurement error, with large differences obtained from the different estimation methodologies. There are a number of theoretical issues that had been debated in previous regulators' considerations of the issue, such as whether any assumption that franking credits are less than fully valued (at least once distributed) is valid, or whether the large proportion of foreign investment already in the market implies that the marginal value of franking credits should be assumed to be zero.

Industry arguments for a lower gamma include:

- That the current price controls were derived using a gamma assumption of 0.3, and that there is insufficient evidence to move away from the existing value 0.3.
- That the value of imputation credits should reflect the value placed on them by the marginal investor, in particular, the marginal investor in the utility sector is a foreign investor, who is unable to use imputation credits.
- That there is little difference between the use of a domestic CAPM (with a low gamma) and an international CAPM because the effects of foreign investors are already embedded in the data that is used to calculate the market risk premium.
- That regarding empirical evidence, estimates of gamma in Cannavan, Finn and Gray (2002), suggest that gamma should be zero.

The issue as to whether the market values of Australian firms reflect a value attributable to franking credits remains a controversial issue.

Regarding the conceptual material that has been advanced, the Commission notes that uncertainty over such matters as to the extent to which the prices of Australian assets are set in international capital markets makes it difficult to interpret this material.

The Commission accepts that discussion of the question as to the relevance of the international versus domestic CAPM has at times been confused. To clarify, it accepts that if the prices of Australian assets are set with reference to an internationally diversified portfolio of assets, then the domestic and international CAPM will give similar estimates of the cost of capital, *provided that* all of the inputs to the domestic CAPM reflect this international price setting environment. The important question then becomes whether the assumption about inputs such as the market risk premium – which is influenced largely by historical observations – is more reflective of a domestic or international price setting environment (with the risk premium for the latter expected to be lower). This is a difficult question to answer.

Accordingly, the Commission is of the view that conceptual analyses do not help to determine how the value attributable to franking credits should be estimated. Rather it considers it appropriate – and consistent with the imperatives of the Reset Schedule – to place most weight on the empirical evidence of the value of franking credits. This best reflects prevailing market conditions that would face investments such as ETSA Utilities. The results of the empirical studies on the value of franking credits are reported in Table 10.9.

The Commission considers it appropriate to place weight on the study by Cannavan et al (the results of the study are summarised in Table 10.9) but notes that whilst the study was a very careful analysis, all estimation techniques suffer from problems. The study by Cannavan et al was restricted to a limited number of companies (albeit with many observations for each) all of which were very large and had large foreign shareholdings. This may affect the ability to apply the results to the Australian market generally. Using specialised markets, such as individual share futures markets, to infer the value of franking credits also raises the question as to whether this methodology provides an estimate of the value that is placed upon franking credits by the long term investors in the firm. Also, the value estimated by such an approach is sensitive to the option pricing formula assumed.

In contrast, dividend drop-off studies – which have been the dominant methodology for estimating the effects of investor taxation on market valuations – do provide results that reflect the effects of dividend imputation across all listed companies. However, this technique suffers from the possible effect of confounding factors around the time of dividends being paid,[147] as well as generally low levels of precision in the estimates, other econometric problems (such as little variation in the degree of franking across companies)

[147] More accurately, going ex dividend.

and potential biases from the fact that share prices can only move by defined increments (or 'ticks'). It is also debated as to whether observations around the time of dividend payments reflect the preferences of long term investors or short term arbitrageurs. Similarly, the use of aggregate taxation statistics raises the question of whether average values are an estimate of marginal values. The techniques that have relied on trades within the ex dividend period and rights issues also suffer from the question of whether these investors are the long term investors who ultimately determine the value of franking credits.

Table 10.9: Estimates of the Value of Franking Credits

STUDY	METHOD	STUDY PERIOD	VALUE OF CREDITS
Hathaway and Officer (1999)	Aggregate taxation statistics	1989-90 to 1994-95	0.60
Hathaway and Officer (1999)	Dividend Drop-off	1/1/85 to 30/6/95	Industrials: 0.61 Resources: 0.61. All stocks: 0.63
Brown and Clarke (1993)	Dividend Drop-off	1/7/87 to 30/6/89 (excluding periods 29/5/88 to 30/6/88), and 1/7/89 to 30/6/91	0.16 0.81
Brukner, Dews and White (1994)	Dividend Drop-off	1987-1990, 1990-1993	0.335 0.688
Walker and Partington (1999)	Simultaneous ex-div/ cum-div trades	1/1/95 to 1/3/97	0.88 – 0.96
Twite and Wood (2002)	Derivative prices	16/5/94 to 31/12/95	0.45
Cannavan, Finn and Gray (2002)	Derivative prices	May 1994 to Dec 1999	Pre 45 day rule: 0.10 Post 45 day rule: -0.13
Chu and Partington (2001)	Rights issue	January 1991 to December 1999	Almost fully valued
Chu, Lonegran, Partington, Stewart (2001)	Rights issue	January 1991 to December 1999	Almost fully valued

Source: Hathaway, N and R. Officer, 1996, The Value of Imputation Tax Credits, working paper, Melbourne Business School, p. 13 and table 1; Brown, P and A. Clarke, 1993, 'The Ex -Dividend Day Behaviour of Australian Share Prices Before and After Imputation', Australian Journal of Management, Vol. 18, table 7 and footnote 39; Bruckner, K. Dews, N and D. White, 1994, 'Capturing Value from Dividend Imputation', McKinsey and Company, quoted in Cannavan, D., F. Finn and S. Gray, 2002, 'The Value of Imputation Tax Credits', working paper, University of Queensland and Duke University, p. 14; Walker, S. and G. Partington, 'The Value of Dividends: Evidence from Cum-Dividend Trading in the Ex-Dividend Period', Accounting and Finance, vol. 39, p.293; Twite, G. and J. Wood, 2002, 'The Pricing of Australian Imputation Tax Credits: Evidence from Individual Share Futures Contracts', working paper, Australian Graduate School of Management, p.22; Cannavan, D., F. Finn and S. Gray, 2002, 'The Value of Imputation Tax Credits', working paper, University of Queensland and Duke University, Table 41; Chu, H., G. Partington, 2001, The Market Value of Dividends: Theory and Evidence from a New Method, working paper, University of Technology, Sydney, p.39; Chu, H., W. Lonegran, G. Partington, R. Stewart, 2001, Dividend Values Implicit in Rights Prices, working paper, University of Technology, Sydney, p.22.

Finally, Australian energy regulators have almost uniformly adopted a value for gamma of 0.5,[148] which is shown in Table 10.10.

[148] IPART is the exception in this table, which adopts a range of 0.3 to 0.5, but as noted earlier, it also adopts a lower range for the market risk premium of 5% to 6%.

Table 10.10: Gamma Assumptions used by Australian Regulators in Relevant Decisions

INDUSTRY	YEAR	GAMMA
Electricity Distribution		
NSW Distributors	IPART, 2004	0.5
ActewAGL	ICRC, 2004	0.5
Aurora	OTTER, 2003	0.5
Queensland Distributors	QCA, 2001	0.5
Victoria Distributors *	Victorian ESC, 2000	0.5
ETSA Utilities	SA Govt, 1999	0.2 – 0.4
Electricity Transmission		
Transend	ACCC, 2003	0.5
Murraylink *	ACCC, 2003	0.5
ElectraNet *	ACCC, 2002	0.5
SPI PowerNet *	ACCC, 2002	0.5
Powerlink	ACCC, 2001	0.5
Gas Distribution		
Victorian Distributors *	Victorian ESC, 2002	0.5
Envestra * / Allgas	QCA, 2001	0.5
AGL *	IPART, 2000	0.3 – 0.5
Albury Gas Company *	IPART, 1999	0.3 – 0.5
AlintaGas	OFFGAR, 2000	0.5
Great Southern Networks	IPART, 1999	0.3 – 0.5
Gas Transmission		
Moomba to Sydney Pipeline *	ACCC, 2003	0.5
GasNet *	ACCC, 2002	0.5
Moomba to Adelaide Pipeline *	ACCC, 2001	0.5

Source: Essential Services Commission, October 2002, Review of Gas Access Arrangements – Final Decision, p.144; Queensland Competition Authority, May 2001, Final Determination – Regulation of Electricity Distribution, p.98; Office of the Regulator General, September 2000, Final Decision – Electricity Distribution Price Determination 2001-05 Volume I Statement of Purpose and Reasons, p.120; Independent Pricing & Regulatory Tribunal, December 1999, Final Determination – Regulation of NSW Electricity Distribution Networks, p.45; Queensland Competition Authority, October 2001, Final Decision – Proposed Access Arrangements for Gas Distribution Networks, Allgas Energy Limited & Envestra Limited, page 231; Independent Pricing & Regulatory Tribunal, June 2000, Final Decision – Access Arrangement for AGL Networks Limited, p.64; Independent Pricing & Regulatory Tribunal, December 1999, Final Decision – Access Arrangement for Albury Gas Company Limited, p.6; Office of Gas Access Regulation, June 2000, Final Decision – Access Arrangements for Mid-West and South-West Gas Distribution System, Alinta Gas, Part a-17; Independent Pricing & Regulatory Tribunal, March 1999, Final Decision – Great Southern Energy Gas Networks Pty Ltd, p.24; Office of the Regulator General, October 1998, Access Arrangements – Multinet Energy Pty Ltd, Westar Gas Pty Ltd, Stratus Gas Pty Ltd – Final Decision, p.10; ACCC, 2001, Queensland Transmission Revenue Cap 2002-2006/07, November, p.28; ACCC, 2002, South Australian Transmission Network Revenue Cap 2003 – 2007/08, December, p.41; ACCC, 2002, Victorian Transmission Revenue Caps 2003-2008, December, p.33; ACCC, 2002, Final Decision – GasNet Australia Access Arrangement Revisions, November, p.112; ACCC, 2001, Access Arrangement for the Moomba to Adelaide Pipeline – Final Decision, September, p.53; ACCC, Access Arrangement for Transmission Pipelines Australia – Final Decision, October, p.62.

* These companies are privately owned and so are clause 7.2(k) benchmarks.

Considering the data contained in both of the tables presented above, the Commission has formed the view that a gamma value of 0.5 best reflects the prevailing market conditions. While the data on the value of franking credits presents a broader range of outcomes for the value of gamma, the Commission needs to take account of regulatory decisions, which have a narrower range, as it must determine a range which more closely reflects ETSA Utilities' business. While it notes that different techniques for estimating the

value of imputation credits and associated estimates are emerging in the finance literature, the Commission does not consider that the evidence is sufficiently strong at this stage to displace market observations and thereby justify a different assumption.

The Commission determines that it will adopt a value of 0.5 for imputation credits (gamma).

10.9 Relevance of Unique Events

The Commission has decided that the most appropriate framework for updating ETSA Utilities' price controls for the 2005-2010 regulatory period is to set prices with reference to cost. In turn, this implies that ETSA Utilities expects to earn its cost of capital on average, taking account of all possible events.[149]

In practice, the possibility of extraordinary events, such as major infrastructure failure, may not normally be taken into account when setting revenue benchmarks. For reasons of simplicity, it is not practical to consider all relevant factors, including those remote and immaterial, when making a determination.

The Commission considers that pass-through is the appropriate mechanism to cater for extraordinary events, and in particular, that addressing such events if and when they occur may reduce the costs borne by customers. Using this mechanism is consistent with evolving practice amongst the other Australian regulators.

The Commission notes, however, that the events that are covered by pass-through clauses need to be very clearly defined to avoid subsequent uncertainty or dispute - they must be restricted to events that actually are extraordinary so that the incentive for ETSA Utilities to be efficient is not diminished.

The issues relating to pass through are discussed in Chapter 13 of this Determination.

10.10 The Commission's Determination on the Regulatory Rate of Return

Previous sections of this chapter have focussed on the various parameters that should be used as input into the formula for the calculation of the appropriate rate of return that should apply for the 2005-2010 regulatory period to ETSA Utilities' regulatory asset base. This section summarises the parameters used and computes the rate of return that is derived from using these variables.

The estimate of the real pre tax cost of capital that the Government used to set the current price caps, and the parameters from which that cost of capital estimate was derived, are set out in Table 10.11. This table also sets out the estimate of the real pre tax cost of

[149] Note that this statement is an approximation to how the Commission has proposed to update ETSA Utilities' price controls. The combination of an efficiency carry-over amount and decisions that are weighted towards ETSA Utilities' interests would imply that it would be expected to earn a return that exceeds its cost of capital.

capital (6.81%) that is consistent with the Commission's determination as set out in this paper.

Table 10.11: Cost of Capital Estimates and Key Input Parameters

DEFINITION	FIRST REGULATORY PERIOD (2001-2005)	THE COMMISSION'S DETERMINATION
Risk free rate (nominal)	5.40% to 5.70%	5.72%
Risk free rate (real)	2.83% to 3.12%	3.25%
Inflation	2.5%	2.39%
Equity beta	0.83 to 1.2	0.8
Market risk premium	6% to 7%	6.0%
Debt credit margin	*1% to 1.4%*	*1.3%*
Transaction cost of debt	-	*0.125%*
Allowance for 'market pressuring'	-	-
Inflation hedging of debt	-	-
Timing hedging of debt	-	*0.1825%*
Debt premium (total)	1% to 1.4%	1.64%
Gearing level	50% to 60%	60%
Corporate tax rate (tc)	36%	30%
After-tax cost of equity, Ke (nominal)	10.38% to 14.1%	10.5%
After-tax cost of equity, Ke (real)	7.34% to 10.65 %	7.9%
After-tax cost of debt, Kd (nominal)	6.39% to 7.13%	7.4%
After-tax cost of debt, Kd (real)	3.80% to 4.49%	4.9%
Value of imputation credits (γ)	0.2 to 0.4	0.5
Pre-tax WACC (real) after allowing for imputation	8.26%	6.81%

Source: ERSU submission to ACCC on South Australian EPO, Attachment B: Cost of Capital for Distribution & Transmission Target Revenue: KPMG, June 1999; ETSA Utilities, Response to Discussion Paper, September 2003; ESCOSA Analysis.

It is important to note that a number of the inputs to the Commission's determination on WACC reflect the latest market evidence to this point in time, but will be updated prior to the Commission's final determination of price controls for the 2005-2010 regulatory period. The inputs that will be updated, and the time at which the WACC estimate will be finalised, have been discussed earlier in this chapter.

11 DETERMINING DISTRIBUTION REVENUE

The Commission has in the previous chapters described all the necessary components for calculating ETSA Utilities' annual revenue requirement pursuant to the building block approach. This included the capital and operating expenditure benchmarks, and the calculation of the regulatory rate of return and depreciation amounts.

This chapter sets out the total revenue requirement that ETSA Utilities will be able to recover through its distribution tariffs for providing prescribed distribution services over the 2005-2010 regulatory period. The derivation of the actual distribution tariffs that will apply from 1 July 2005 is discussed in chapter 12.

Part D of chapter 6 of the National Electricity Code ("the NEC") provides the general framework for determining the annual revenue requirement that ETSA Utilities can recover for providing prescribed distribution services. This includes setting the objectives and principles for the regulatory regime governing distribution network pricing. The Commission has had regard to Part D in determining the annual revenue requirements.

This chapter firstly discusses the requirement in the Electricity Pricing Order ("the EPO") to apply incentive based regulation adopting a CPI-X approach. The Commission's interpretation of incentive based regulation is that the annual revenue requirements are set with reference to predefined expenditure benchmarks that are not reviewed over the regulatory period (notwithstanding regulated pass throughs discussed in chapter 13).

The EPO also requires the Commission to adopt an average revenue form of regulation. The main implication is that the Commission must convert the annual revenue requirement into a maximum amount that ETSA Utilities can recover per unit of output. This chapter sets out the Commission's approach to meeting its obligation to apply average revenue controls. The actual average revenue controls are set out in chapter 12.

The manner in which the notional revenue requirement, determined using the building block approach, is converted into an allowed revenue path is also discussed. This revenue path has been determined with a "P-nought" adjustment, which adjusts the one-off average revenue between the current and 2005-2010 regulatory periods and through the calculation of an X factor, which dictates the amount by which ETSA Utilities' average revenue changes in real terms each year. The X factor is incorporated into the revenue control formula, which is discussed in more detail in chapter 12.

11.1 Interpretation of CPI-X regulation

Clause 7.2(a) of the EPO requires the Commission to utilise "incentive based regulation adopting a CPI-X approach". The Commission has examined the meaning of this requirement to ensure that it complies with this legal obligation.

The Commission acknowledges that there has been some variation in the application of incentive based regulation using a CPI-X approach as it has evolved, and recognises that

it will continue to evolve. This was also recognised by the Supreme Court of Victoria when it considered the legal meaning of certain terms including "CPI-X approach" in relation to electricity regulation in that State. In concluding on the meaning of the term "CPI-X approach", Justice Gillard noted that:

> *... the concept is recent and is developing in response to changed circumstances and the lessons of experience in its application to price fixing in various public utilities.*[150]

There are two broad approaches for reviewing price controls under a CPI-X approach. The difference in approaches reflects the extent to which the new price controls are set with reference to the utility's costs (either at the time of the review or forecast over the forthcoming period) on the one hand, or with reference to external benchmarks, on the other.

The Commission believes that the most practical approach for reviewing ETSA Utilities' price controls for the 2005-2010 regulatory period is with reference to ETSA Utilities' efficient costs, albeit with reference to external benchmarks where relevant (as discussed in Chapters 7 and 8).

The Commission acknowledges that this means of applying incentive based regulation has some similarities with rate of return regulation, in so far as prices in both are linked to costs initially. However, the key differences between 'rate of return' and incentive based regulation concern what happens *after prices have been reviewed.*

Under incentive based regulation:[151]

- there is a predefined period between cost based price reviews, which provides incentives for generating ongoing efficiencies (providing benefits to both the regulated business and customers); and
- as discussed further below, is usually accompanied with additional flexibility for utilities over tariff structures (that is, regulatory controls are generally applied to some form of average price, rather than to each individual price).

The approach proposed for implementing CPI-X regulation is essentially the same as the regulatory framework that is currently applied to ETSA Utilities under the EPO. That is, the current price controls have been set with reference to ETSA Utilities' costs of providing the regulated services, a predetermined period was set between reviews, and ETSA Utilities has had a degree of discretion over the design of specific charges.

The approach foreshadowed above for implementing "incentive based regulation adopting a CPI-X approach" implies that the Commission must establish a benchmark of the

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[150] Supreme Court of Victoria, *TXU Electricity Limited (formerly known as Eastern Energy Ltd) v Office of the Regulator-General & Ors* [2001] VSC 153 (17 May 2001).

[151] Under CPI-X regulation as implemented in UK and Australia, the cost of providing regulated services have generally been determined with reference to forecasts over the regulatory period ('forward-looking benchmarks'), rather than with reference to costs incurred in a historical period, which would not normally occur under 'rate of return' regulation. However, it is possible to set price caps with reference to historical costs, and which have the same incentive properties to price caps set with reference to forecasts of costs, and which would be characterised as CPI-X regulation.

efficient cost (including opportunity cost) of providing prescribed distribution services for the 2005-2010 regulatory period. The new price controls are then set such that ETSA Utilities should *expect* to recover that amount — although its actual financial performance over the period will depend upon factors such as its ability to make efficiency gains. The issues associated with deriving the benchmark of efficient expenditures are discussed in more detail in Chapters 7 and 8.

11.2 Average revenue control

The EPO requires that the CPI-X approach be applied to average revenue. This means that the Commission will need to set a maximum revenue that ETSA Utilities may earn *per unit*, as opposed to (for example) a control on total revenue. The EPO does not specify which *unit* should be used to determine the maximum average revenue.

Under the current system, the average revenue is calculated per Megawatt-hour (MWh), which is a measure of the amount of energy delivered. Different averages are determined for different customer categories, reflecting the different costs of serving different customer types.

A feasible alternative is to determine an average revenue per Megawatt (MW) or kilowatt (kW), which measure the total capacity that a customer may demand. While the customer may not always draw on the full network capacity, the cost of building and maintaining a distribution network depends largely on the capacity that the network must be able to deliver at any particular time.

There may be arguments that support the use of capacity (MW) over energy used (MWh) given that capacity is the major cost driver. However, usage (MWh) is a derivative of capacity and there is generally a reasonable correlation between usage and capacity, with the relationship varying dependent on load profile.

Further, accurately measuring capacity for each customer category is not always feasible, especially for smaller customers who do not have demand meters. Compliance cost for capacity based average revenue ($/MW) would be likely to outweigh any benefits that it would generate. Therefore, the Commission has concluded that it will continue to apply usage ($/MWh) as the weighting for the average revenue control in the 2005-2010 regulatory period.

The EPO currently specifies a system-wide Maximum Average Distribution Revenue ("MADR") control, where the average revenue is calculated as the weighted average of the revenue yield (in $/MWh terms) across 10 different customer classes. The annual forecast sales for each of the customer classes are used as weights.

The MADR is calculated as a weighted average yield across all customer classes, to ensure that prices are reflective of the different costs of supplying certain types of customers. This provides ETSA Utilities with a clear incentive to supply all customer types by ensuring that the revenue yield for each customer category is greater than the cost of supplying that customer group.

An alternative to a single MADR control would be to establish separate average revenue controls for each of the customer classes. Separate average revenue controls would ensure that the relative yields between customer groups are maintained over the regulatory period, as opposed to the weighted MADR, which allows actual individual average revenues to change from that forecast under the EPO, so long as the overall MADR is complied with. The Commission has considered whether it should develop separate average revenue controls for different customer categories, or whether a single MADR control should apply as is currently the case under the EPO.

The Commission believes that a single MADR control based on weighted average revenues for each customer category leads to two undesirable outcomes:

- as the weights used to calculate the MADR depend on the distributor's annual forecasts, it is open to some manipulation (eg. it provides an incentive to over-forecast high yield customers relative to low-yield customers); and
- as the MADR term is locked-in at the start of each year, the same marginal revenue from supplying additional load is obtained, irrespective of the type of customer. As marginal (and average) cost is likely to differ across customer classes, a single MADR may be inappropriate.

The Commission therefore proposes to establish separate average distribution revenue controls for each customer class. This will ensure that if more sales are made than forecast for a high yield customer class (eg. residential customers), allowed revenue increases according to that higher yield.

11.3 Notional Revenue Requirements

The Commission has used the building block approach to determine ETSA Utilities' average revenue controls. This approach is consistent with the EPO requirement that the Commission must have regard to, *inter alia*, ETSA Utilities' costs during the 2005-2010 regulatory period. The building block typically determines a forward-looking revenue benchmark comprising of a return on the regulated asset base, depreciation, operating expenditure and an efficiency carryover amount. The Commission's decisions in relation to each of these components were discussed in previous chapters. However, the following sections summarise the impact of each of these decisions on the aggregate revenue requirement.

11.3.1 Return on Assets

The Commission's decision regarding the allowed rate of return on ETSA Utilities' regulated asset base was discussed in chapter 10. As a result of this decision, the component of annual revenue representing a regulatory return on assets will decrease in comparison to that allowed during the current regulatory period under the EPO. Table 11.1 shows the contribution of the return on assets and working capital to the notional revenue requirement.

11.3.2 Depreciation

The revenue requirement also includes an amount reflecting depreciation over the 2005-2010 regulatory period, as discussed in chapter 9. This amount is higher than depreciation in the 2000-2005 regulatory period due to an increase in the capital expenditure benchmark. Table 11.1 sets out the depreciation amounts over the 2005-2010 regulatory period.

11.3.3 Operating Expenditure

The notional revenue requirement includes the Commission's determination on the operating expenditure that an efficient distributor would incur in providing prescribed distribution services over the 2005-2010 regulatory period. As discussed in chapter 8, the Commission has determined that ETSA Utilities' operating expenditure benchmark should be increased over current levels of expenditure. Table 11.1 incorporates the Commission's operating expenditure benchmark into the revenue requirement.

11.3.4 Efficiency Carryover Amount

As discussed in chapter 6, the Commission has determined that a zero efficiency carryover amount will apply in the 2005-2010 regulatory period, following the calculation of negative efficiencies during the current period.

Using the Commission's Building Block formula, as discussed in Chapter 9, the Commission has determined an average annual revenue requirement of approximately $438m per annum over the 2005-2010 regulatory period. Table 11.1 shows the contribution of each "building block" to this revenue requirement. The approach used by the Commission in translating this notional revenue requirement into smoothed average revenues is discussed in the following section.

Table 11.1: ETSA Utilities Unsmoothed ("Notional") Revenue Requirement for the 2005-2010 Regulatory Period ($000's in March 2004 prices)

	2005/06	2006/07	2007/08	2008/09	2009/10
Return on Assets	164,894	164,910	164,652	164,242	164,309
Return on Working Capital	2,111	2,111	2,111	2,111	2,111
Depreciation	141,027	146,032	147,801	146,169	146,013
Operating Expenditure	122,685	125,046	125,497	127,833	128,545
Efficiency Carryover	-	-	-	-	-
Notional Revenue (Total)	**430,718**	**438,099**	**440,062**	**440,356**	**440,978**

11.4 Setting the X Factor

While the EPO requires the Commission to adopt a CPI-X form of regulation, it does not impose any specific requirement as to what the X factor should represent or how it should be determined. Given this, the Commission has determined that the X factor will be used to 'smooth' the price path during the regulatory period. This is consistent with most of the decisions made by Regulators in the UK and Australia, whereby the X factor is determined such that expected revenue over the period (taking account of demand growth) is equal to forecast efficient costs (both in present value terms). The prices within a regulatory period will therefore decline in real terms by this factor of 'X'.

The EPO requires that the X factor, however calculated, is set such that only one X factor applies throughout the regulatory period. This approach is consistent with CPI-X regulation where the X factor serves to smooth the cash flows over the regulatory period. The X factor does not necessarily represent expected future efficiencies, rather these are incorporated into expenditure benchmarks earlier in the process.

Given the difference between the current revenue requirement to the notional revenue requirement for 2005/06, the Commission has considered whether prices should be transitioned through a one-off adjustment to prices (a "P-nought" adjustment) or through a gradual change over the regulatory period (the X factor), or by a combination of both.

The key issue is managing price volatility between periods and avoiding price shocks to consumers. From the regulated business' point of view, the method of adjustment does not have any long-term financial impact, since both methods result in the same expected revenue recovery in net present value terms.

In reaching a decision on this matter, the Commission has sought to achieve two objectives. First, it has chosen a P-nought and X value such that the net present value ("NPV") of the allowed tariff revenue over the 2005-2010 regulatory period is the same as the forecast revenue requirement over this period. This NPV has been calculated using the Commission's proposed real pre tax WACC of 6.81%. The forecast revenue requirement is determined by applying the sales assumptions to the average revenue controls and calculating the revenue that this would generate over the 5-year period.

Along with this primary objective, the Commission has also attempted to match the notional revenue requirement in 2009/10 to the allowed revenue requirement for that year. This has been done to ensure that prices in the 2010-2015 regulatory period are as cost reflective as possible.

With these objectives in mind, the Commission has calculated a P-nought adjustment of 7% (ie. a real reduction in average revenue of 7%) and X factor of 1.3% (ie. prices will be adjusted by CPI minus 1.3% each year thereafter). The Commission has calculated this X factor to provide a smooth average revenue path over the 5-year period (as opposed to smoothing total revenue).

A comparison of the allowed revenue requirement that results from these adjustments to the notional revenue requirement is set out in Table 11.2.

Table 11.2: Notional and Allowed Revenue Requirements for the 2005-2010 Regulatory Period ($000's in March 2004 prices)

	2005/06	2006/07	2007/08	2008/09	2009/10	NPV
Notional Revenue Requirement	430,718	438,099	440,062	440,356	440,978	**1,803,972**
Allowed Revenue Requirement	435,613	436,237	437,349	438,652	440,982	**1,803,391**

As will be discussed in the following chapter, the P-nought adjustment does not represent the change in total revenue recovery by ETSA Utilities between 2004/05 and 2005/06, nor does it necessarily represent the change in distribution prices that any particular customer can expect to receive in 2005/06. The P-nought adjustment reflects a change in average revenue between the two years, and is determined by a number of variables, including forecast changes in sales. Chapter 12 discusses the relative importance of changes in these variables in explaining the P-nought adjustment.

Having developed the allowed revenue requirements, the Commission has then allocated the revenue to various distribution cost drivers as part of the process of developing distribution tariffs. The cost allocation approach used by the Commission is discussed in the following chapter.

12 DETERMINING DISTRIBUTION TARIFFS

Earlier chapters have described how the Commission has determined the annual revenue requirement for each year of the 2005-2010 regulatory period in accordance with the building block formula. This includes a description of how all the components of the building block formula have been derived in calculating the yearly revenue requirements.

This chapter is primarily concerned with translating the annual revenue requirement into the distribution tariffs that ETSA Utilities can charge customers.

The first stage in this process involves allocating the annual revenue requirement to different customer groups, which is often referred to as cost allocation. A national framework for cost allocation is contained in Part E of chapter 6 of the National Electricity Code ("the NEC"), which sets out key pricing principles governing the method for allocating the annual revenue requirement to customer groups.

Part E allows regulators, in consultation with market participants, to develop their own pricing principles for cost allocation rather than adopt those set out in the NEC.[152] The Commission has decided to exercise its discretion under the NEC and develop its own pricing principles (as has every other regulator in Australia). This chapter describes the NEC framework and sets out the pricing principles developed by the Commission to replace those in the NEC.

The pricing principles are used as the basis for deriving the average revenue controls that will apply over the 2005-2010 regulatory period[153]. The average revenue controls are the primary controls used to regulate ETSA Utilities' revenue recovery. The average revenue controls dictate the amount of revenue that ETSA Utilities can recover per unit, which is to be measured by sales (Megawatt-hours).

Once the basis of the average revenue control is determined, the next step is determining how the average revenue controls can change on an annual basis. These charges are driven by the revenue control formula. The revenue control formula adjusts the average revenue controls for inflation (CPI) less the X factor determined by the Commission, along with the other variables that influence ETSA Utilities' revenue, such as its performance under the service incentive scheme.

The final stage is translating the average revenue controls into the distribution tariffs that ETSA Utilities can charge different customers. The pricing principles developed by the Commission guide the structure of ETSA Utilities' tariffs. These tariffs must be set in a manner that is consistent with the revenue control formula and pricing principles.

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[152] NEC, clause 6.11(e).

[153] As required by clause 7.2(a) of the EPO.

12.1 National Electricity Code framework

The NEC requires that each participating jurisdiction appoint a regulator that is responsible for the regulation of distribution service pricing. The Commission fulfils this role in South Australia.[154] The NEC provides a set of national pricing principles and objectives to be followed by the Commission in fulfilling its role as the jurisdictional regulator.

Part E of chapter 6 of the NEC relates to translating the annual revenue requirement into distribution tariffs. This predominantly involves a set of pricing principles that govern how the annual revenue requirement is to be allocated to different customer categories for the purpose of determining distribution tariffs.

Clause 6.11(e) of the NEC allows the Commission to develop alternate pricing principles and methodologies from that set out in Part E. The NEC states that any alternate pricing methodology must conform to any applicable rules or guidelines developed by the regulator in accordance with Part D, which sets the objectives and principles governing distribution network pricing.

The alternate pricing principles and methodologies developed by the Commission pursuant to clause 6.11(e) of the NEC have equivalent standing to NEC provisions. This implies that, in order to comply with the NEC, ETSA Utilities must comply with the principles and related methodologies set out in the Commission's final price determination.

In developing the alternate pricing methodology, the Commission must be mindful of the key principles and core objectives that apply to distribution network pricing under Part D. These key principles and core objectives apply to both the manner in which regulation is implemented and to the pricing outcomes achieved by regulation.[155]

The regulatory objectives require a consistent, efficient and cost effective regulatory regime to be implemented.[156] The regulatory regime must be accountable through the public disclosure of regulatory processes and decisions. The NEC also requires that the regulatory regime be incentive based and balance the interests of all stakeholders.

The pricing objectives require the regulatory regime to establish an environment that fosters efficient investment and operation of the distribution network.[157] The NEC also requires the regulatory regime to foster efficient investment and competition in upstream (generation and transmission) and downstream (retail) sectors. The objectives also require price stability and equity for distribution network users.

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154 Pursuant to regulation 5C(1)(c) of the Electricity (General) Regulations 1997.

155 See clauses 6.1.1 of the NEC.

156 See clause 6.10.2 of the NEC.

157 Ibid.

Currently no jurisdictional regulators are implementing the pricing principles and methodologies outlined in Part E, having instead chosen to implement alternative arrangements. Jurisdictional regulators have put forward several criticisms of Part E in justifying their decisions to implement alternate arrangements. These criticisms include that Part E:

- prescribes a mechanistic approach for pricing that lacks scope for judgement to be used;
- requires a heavy involvement of the regulator in determining compliance with each interim step of cost allocation; and
- is likely to deliver unclear pricing signals to distribution network users.

For similar reasons, the Commission has also decided to depart from Part E and develop its own pricing principles and methodologies.

The NEC requires the Commission to consult with relevant stakeholders before implementing an alternate pricing methodology. The Commission intends to conduct this consultation process through the release of this draft price determination.

12.2 Pricing Principles

Pricing principles guide the manner in which the distributor recovers its allowed revenues from distribution network users and the structure of its tariffs.

The pricing principles therefore influence the level and structure of prices for different customer groups. A distributor's prices can facilitate efficient economic outcomes by influencing investment decisions, both by the distributor and related industries, and by encouraging efficient use of the network by customers.

Given the important role of pricing principles and the above-mentioned issues associated with Part E, the Utility Regulators Forum (URF) has recently decided to develop a national set of pricing principles. The URF intends to develop a nationally agreed set of high level principles that can be used in place of Part E, pursuant to clause 6.11(e) of the NEC.

The URF intends to commence public consultation in December 2004 on appropriate pricing principles and will seek to finalise these principles by March 2005. The Commission has developed its principles to be consistent with those currently proposed by the URF.

The Commission has sought to develop high level principles that do not prescribe specific outcomes that ETSA Utilities must achieve. For example, the principles prescribe the objectives and factors that ETSA Utilities should consider in setting its distribution tariffs rather than the actual tariffs.

Such high level principles are appropriate given that ETSA Utilities has the best knowledge of its underlying cost structures and customers' needs. The Commission has

sought to ensure that the regulatory framework provides appropriate incentives for ETSA Utilities to apply the principles in an unbiased manner.

In some cases the principles might conflict, such as the requirement for ETSA Utilities to maintain statewide postage stamp pricing for distribution services and for prices to reflect the efficient economic cost of service provision. ETSA Utilities is required to use its judgement in cases where a conflict exists and explain the reasons for its decisions.

The proposed pricing principles, which relate to the provision of prescribed distribution services, are as follows:

- prices are to be determined in accordance with the formulae and principles contained in this Electricity Distribution Price Determination, including, but not limited to, the formulae set out in the Formula Schedule;
- prices should lie on or between the value of avoidable cost and the value of stand alone cost (these concepts are discussed in section 12.2.2 below);
- prices should be based on a well defined and clearly explained methodology that seeks to reflect the efficient economic cost of service provision;
- distribution charges are to be allocated to small and large customers on a statewide "postage stamp" basis;
- provided that economic costs are covered, prices should be responsive to the requirements and circumstances of users in order to:
  - avoid uneconomic bypass; and
  - allow negotiation to better reflect the economic value of specific services, including services associated with embedded generation and other options;
- ETSA Utilities is to use its best endeavours to ensure that the pass through of costs to customers for transmission network services is cost reflective; and
- ETSA Utilities is to have regard to the impact of its prices on customers, including:
  - the impact of its price structures on customers within the same customer group; and
  - developing price signals that encourage energy efficiency by large users wherever possible.

An explanation of the intent of the pricing principles is set out below.

12.2.1 Prices are to be determined in accordance with the formulae and principles contained in this Electricity Distribution Price Determination, including, but not limited to the Formula Schedule.

The Commission, through this draft price determination, has provided ETSA Utilities with sufficient revenue to recover the efficient costs of providing prescribed distribution services taking into account the matters required by the NEC, the Electricity Pricing Order ("the EPO"), the Electricity Act and the Essential Services Commission Act ("the ESC Act"). ETSA Utilities will be able to earn a return on its

capital investment equal to the regulatory return if it meets the efficiency benchmarks set by the Commission and if the ESIPC sales forecasts are accurate.

The Formula Schedule of this draft price determination sets average revenue controls that enable ETSA Utilities to recover the efficient expenditure benchmarks set by the Commission. ETSA Utilities is to ensure that prices are set in a manner that complies with the Formula Schedule, so that the corresponding prices recover no more than the average revenue allowed for by this draft price determination.

The Commission has also implemented a tariff rebalancing control aimed at providing flexibility to ETSA Utilities to alter its tariffs to recover allowed revenue while protecting customers from large price movements between years (see section 12.5). ETSA Utilities must ensure that it complies with this rebalancing control in setting its distribution tariffs.

The Commission will require ETSA Utilities to issue a statement each year describing how its proposed prices comply with the pricing principles. This statement will also need to publicly disclose ETSA Utilities' medium term pricing strategy.[158] This will be published as part of the statement submitted by ETSA Utilities for adjusting its tariffs on an annual basis.

12.2.2 Prices should lie on or between the value of avoidable cost and the value of stand-alone cost.

Prices play an important role in determining how customers use the distribution network and the level of investment in that network over time. Efficient economic outcomes are derived where prices at least recover the avoidable (or incremental) cost of providing a service but are no higher than the stand-alone cost of that service.

The avoidable cost is the cost avoided by the distributor by not supplying a particular customer group (it therefore represents the lower limit of a price that could be charged). The distribution tariff will be based on the additional cost of supplying a customer group and will generally not reflect assets that are also used to supply other customers. Tariffs based on avoidable cost seek to isolate those costs that are solely attributable to a customer group.

For a residential customer, distribution tariffs based on avoidable costs might only include the cost of providing the low voltage distribution lines in residential areas rather than the higher voltage upstream infrastructure, such as substation assets.

[158] This should include a description of how and why ETSA Utilities proposes to change its distribution tariffs over the medium term (no less than for the remainder of the regulatory period) and how such changes would continue to comply with the pricing principles.

This is because such higher voltage assets are also used to supply business customers.[159]

The stand-alone cost is the total cost to the distributor of supplying a particular customer group (it therefore represents the upper limit of a price that could be charged). The distribution tariff will reflect the total cost of all assets that are required to supply a particular customer group, as if other customer groups did not exist. This could include the total of all upstream infrastructure, despite this being used in the supply of other customer groups.

It follows from this that tariffs for a particular customer group would be subsidised if they were below the avoidable cost of supply. This is because there are some parts of the network that would be common to all users, such as substation assets. These upstream costs are unlikely to be included in calculating a tariff based on avoidable cost, as such costs would be wholly allocated to other customer groups.

Likewise, tariffs that are above the stand-alone cost of supply would imply that a subsidy is being provided elsewhere. This would be the case if the total costs allocated using a stand-alone approach included upstream assets that were also used to supply other customers.

The distributor should determine tariffs such that they recover no less than the avoidable cost of supply and no more than the stand-alone supply cost.

Prices lower than avoidable cost would imply that the distributor is not recovering even the incremental supply costs from a particular customer group. Prices higher than the stand-alone cost mean that the distributor is recovering more revenue than is required to supply those customers.

In a regulated market, pricing below avoidable cost would result in the foregone revenue being recovered from other customers, which is referred to as a cross subsidy in pricing. Prices above the stand-alone cost imply that the additional revenue recovered would be used to offset a subsidy provided elsewhere.

Such pricing behaviour is undesirable, as it might lead to a mis-allocation of resources in the economy. This is because resources could potentially be competed away from more productive uses (the group providing the subsidy) and directed towards less productive uses (the group being subsidised).

This phenomenon is often referred to as allocative inefficiency. This is because resources are not allocated in a manner that maximises benefits to society. For example, pricing above avoidable cost might result in a business customer:

[159] Put differently, residential tariffs determined using an avoidable cost approach might be determined by reference to the cost of providing the low-voltage distribution network and not the higher voltage parts of the network, such as substation assets and sub-transmission lines.

- consuming less than an efficient level by constraining the production of a good or service to a level lower than that demanded by society; and/or
- choosing to by-pass the network all together in favour of a more expensive supply option.

This pricing principle seeks to avoid such allocative inefficiencies derived from the distributor's pricing behaviour.

12.2.3 Prices should be based on a well-defined and clearly explained methodology that seeks to reflect the efficient economic cost of service provision.

The measurement and allocation of costs to different customer categories forms the basis of price development under the average revenue control form of regulation. The Commission considers it vital that ETSA Utilities follow a rigorous, efficient and well-defined approach to cost allocation.

The main requirement under this pricing principle is for ETSA Utilities to allocate costs to different customer categories on a cost reflective basis. This is to ensure that the price paid by a customer reflects the economic cost of providing distribution services to that customer.

The Commission notes that developing cost reflective prices is constrained by the legislative requirement for ETSA Utilities to charge on a statewide ("postage stamp") basis for providing distribution services to small customers.[160] ETSA Utilities will need to use its judgement in developing cost reflective pricing given the statewide pricing requirement.

12.2.4 The distribution charge is to be allocated to small and large customers on a statewide postage stamp basis.

Chapter 7 of the EPO requires that statewide pricing be maintained for distribution tariffs set for small customers (annual consumption of less than 160 MWh) over the 2005-2010 regulatory period.[161] This means that the tariffs for small customers within the same customer category (eg. residential) must be the same regardless of their consumption level and location on the distribution network.[162]

For large customers (those consuming above 160 MWh), the EPO provides limited flexibility for departing from the statewide pricing requirement. The EPO requires

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160 Electricity Act, section 35A(2); EPO clause 7.2(e)

161 The NEC defines statewide pricing as: a system of charging network users for transmission service or distribution service in which the price per unit is the same regardless of how much energy is used by the network user or the location in the transmission network or distribution network of the network user.

162 The statewide pricing requirement does not prevent there from being more than one tariff for a customer type (eg. residential or business customer). Rather, it requires that the tariff developed by ETSA Utilities be offered to all small distribution customers regardless of their location on the network.

that greater weight should be given to the statewide pricing principle than any other economic principle.[163] The EPO also requires sunk costs to be allocated on a statewide postage stamp basis.[164]

The main economic principle against statewide pricing is that it limits pricing signals to customers. Consequently economic efficiency, especially allocative efficiency, is reduced.[165] An example is the inability to use prices to signal to customers the areas of the network that are constrained, or where the cost of supply is relatively high.[166]

The Commission is not aware of any principle other than economic principles that would justify moving away from statewide pricing for large customers. Taking into account the guidance provided by the EPO, the Commission has therefore decided to implement statewide pricing for distribution charges across all customer categories.

12.2.5 Provided that economic costs are covered, prices should be responsive to the requirements and circumstances of users in order to:

- **avoid uneconomic bypass; and**
- **allow negotiation to better reflect the economic value of specific services, including services associated with embedded generation and other options.**

Different customers might have different service (or other) requirements that differ from the standard service provided by ETSA Utilities. ETSA Utilities should be sensitive to the individual needs of its distribution customers and seek to cater for these needs where this is possible within the regulatory framework (for example, prices would continue to recover the economic costs of service provision).

Such flexibility may avoid inefficient by-pass of the network. For example, a large distribution network user might bypass ETSA Utilities' distribution network if it considers that:

- this would improve service reliability to meet its requirements; and/or
- this would reduce prices to a level below the current price it is being charged for distribution services.

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163 EPO, clause 7.2(a)(i)

164 EPO, clause 17.2(a)(ii)

165 By virtue of its application, statewide prices will undercharge low cost customers and overcharge low cost customers given that prices are to be the same for all customers. This implies that statewide prices is a form of cross subsidy required to be factored into pricing for distribution services in South Australia.

166 The Commission notes that locational pricing signals are more potent before a customer locates (a new customer) or where the customer is already considering moving. Locational pricing signals are provided through chapter 3 of the Distribution Code, which set the approach for determining network augmentation charges on the network.

This might lead to an outcome whereby a second supplier unnecessarily duplicates ETSA Utilities' distribution infrastructure (i.e. another electricity distribution line or even a gas distribution pipeline).[167]

12.2.6 ETSA Utilities is to use its best endeavours to ensure that the pass through of costs to customers for transmission network services is cost reflective.

The Commission has decided to treat the transmission network services costs incurred by ETSA Utilities as a pass through. This decision is due to the revenue cap form of regulation that currently governs the manner by which ElectraNet SA recovers its annual revenue requirement.

Most of the energy distributed through ETSA Utilities' distribution system is delivered through ElectraNet SA's transmission network. However, this principle will also apply to transmission network services purchased by ETSA Utilities from any other transmission business, so long as these costs are relevant to supplying electricity to distribution network customers.

This principle places a requirement on ETSA Utilities to use its best endeavours to set the transmission component of its network tariffs such that it recovers no more than the forecast costs of purchasing transmission network services. ETSA Utilities is to seek to minimise, to the extent possible, under or over recovery of transmission costs in any year.

In addition, clause 6.10.2(b)(4) of the NEC requires ETSA Utilities to maintain in its distribution tariffs any locational pricing signals that are evident in ElectraNet SA's transmission signals. ETSA Utilities is required to use its best endeavours to comply with this NEC requirement.

12.2.7 ETSA Utilities is to have regard to the impact of its prices on customers, including:

- **the impact of its price structures on customers within the same customer group; and**
- **developing price signals that encourage energy efficiency by large users wherever possible.**

This principle requires that ETSA Utilities consider the impact of its prices on different customers within the same customer group. This particularly relates to how the particular structure of a tariff could have a different impact on similar customers. ETSA Utilities is to demonstrate that its prices achieve an equitable recovery of costs from customers.

[167] Uneconomic to duplicate arises whereby the overall cost to society are lowest where a single supplier meets market demand rather than multiple suppliers.

This principle also requires ETSA Utilities to develop price signals that encourage its customers to utilise the distribution network in a more efficient manner. This principle is consistent with the Commission's focus on demand management initiatives in this draft price determination.

12.3 Derivation of the average revenue controls

ETSA Utilities proposed to the Commission a cost allocation approach that is broadly consistent with the approach used to derive the current average revenue controls under the EPO. This methodology follows a similar framework to that set out in Part E of the NEC, whereby the smoothed revenue requirement for 2005/06 is allocated to different customer categories on the basis of a detailed cost driver analysis.

Although the cost allocation approach is similar to the existing method, ETSA Utilities has updated the allocators with more recent information on customer load profiles. Under the revised approach, residential customers continue to have the highest allocation of costs (and hence the highest average revenue control), although the difference relative to other customer groups is lower than under the EPO.

The Commission is satisfied that ETSA Utilities' proposed approach complies with the pricing principles. This is because the cost allocation undertaken by ETSA Utilities generally replicates the approach used to develop current prices. The Commission believes that the resultant average revenue controls are cost reflective and lie within the range set by avoidable and stand alone costs.

The average revenue controls for 2005/06 reflect a number of decisions by the Commission in this draft price determination, including the:

- derivation of the cost "building blocks";
- changes to the allocation of costs between customer categories; and
- decision for the costs of purchasing transmission services to be treated as a cost pass-through, and as such, not to be included in the average revenue controls.

The 2005/06 average revenue controls determined by the Commission are set out in Table 12.1. These average revenue controls reflect all decisions made by the Commission in this draft price determination. The 2005/06 average revenue controls were derived by applying ETSA Utilities' cost allocators to the annual revenue requirement determined by the Commission for that year.

Table 12.1: Average Distribution Revenues in 2004/05 and 2005/06 ($m in March 2004 prices)*

AVERAGE DISTRIBUTION REVENUE ($/MWH)	2004/05	2005/06	% CHANGE
Sub transmission	3.13	3.33	6%
Zone substation	8.07	8.19	1%
High Voltage/ High Voltage (obsolete)	20.01	20.63	3%
Large Low voltage demand (>1MW)	23.66	25.06	6%
Low Voltage demand (300kW – 1MW)	30.44	31.77	4%
Medium low voltage demand (<300kW)	40.49	40.94	1%
Low voltage business - 2 rate	45.02	46.70	4%
Low voltage business - single rate	65.19	62.33	-4%
Low voltage residential - single rate	75.37	67.60	-10%
Low voltage off-peak controlled load	19.81	13.02	-34%
Low voltage unmetered usage (overnight)	31.95	30.86	-3%
Low voltage unmetered usage (24 hour)	35.10	34.54	-2%
Total	43.78	40.68	-7%

* These average revenue controls are in real dollars, and as such, the 2005/06 average revenues will be adjusted by the annual change in the CPI, as at March 2005.

12.4 Composition of initial average revenue adjustment

As shown in Table 12.1, the average distribution revenue across all customer groups will decrease from $43.78 in 2004/05 to $40.68 in 2005/06. This represents an initial reduction in the average revenue across all customer groups of 7%, which is commonly referred to as a P-nought adjustment.

There are a number of factors that contribute towards this reduction in average revenue.

One of the largest contributors to the adjustment relates to the Commission's decision on the regulatory return on assets, which equates to a reduction in average revenue of approximately $3.28/MWh.

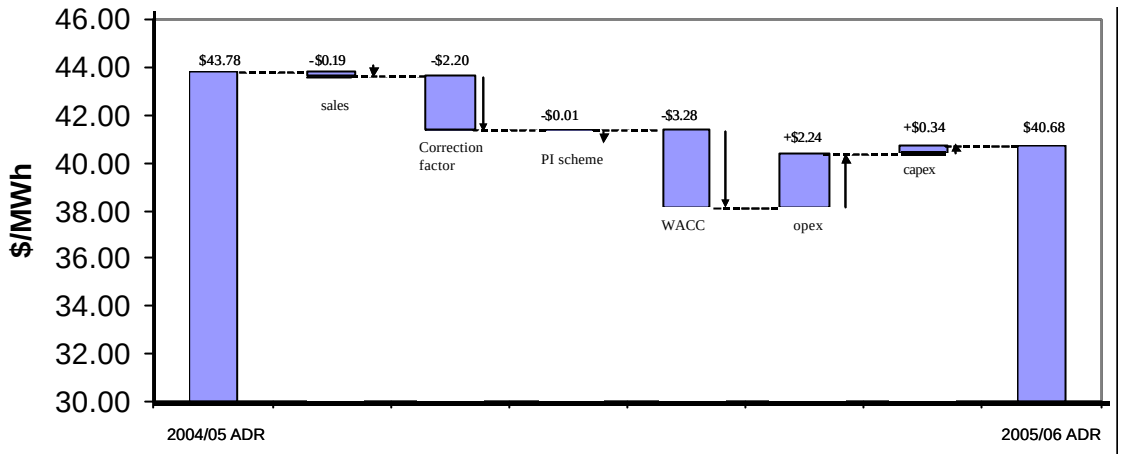
The existence of a correction factor in the 2004/05 average revenue also makes a significant contribution to the reduction, which accounts for around $2.20/MWh.[168] However, the Commission's decision to increase the capital and operating expenditure benchmarks has led to an offsetting increase in average revenue of approximately $2.58/MWh.

The remaining factors relate to the change in sales forecasts between the two years, and the performance incentive scheme revenue earned in 2004/05 (in respect of ETSA Utilities' service level performance in 2003/04), contributing to a decrease of $0.20/MWh.

[168] This correction factor under the EPO allows ETSA Utilities to recover any over or under recover of revenue resulting from proportion shifts in sales.

The factors contributing to the change in average revenue between 2004/05 and 2005/06 are shown in Figure 12.1.

Figure 12.1 Factors contributing to the change in average revenue between 2004/05 and 2005/06



12.5 Average revenue control formula

Schedule 3 of Part B of this draft price determination sets out the Commission's decisions on how the average revenue controls are to be implemented from 1 July 2005. This includes the average revenue control formula, which is the primary control that regulates how average revenues will be adjusted on an annual basis.

The average revenue control formula encompasses all draft decisions made by the Commission in relation to the revenue that ETSA Utilities can recover over the 2005-2010 regulatory period. These decisions are essentially provided in arithmetic form through the average revenue control formula, which is contained in Schedule 3 of Part B of this draft determination.

The average revenue control formula places a limit on the revenue that ETSA Utilities can recover from each of the customer groups set out in Table 12.1. ETSA Utilities must ensure that the distribution tariffs that it develops generate no more revenue than that implied by the average revenue control formula.

The primary control that is imposed on ETSA Utilities is represented by the following formulae:

$$MADR_t = \frac{\left[\sum_{j=1}^{J} (ADR_{t,j} \times FDE_{t,j}) - K_t - Q_t + SI_t + U_t + P_t\right]}{FDE_t} + EPO_t$$

$$ADR_{t,j} = ADR_{t-1,j}\, xCPI_t\,(1 - X_{t,j})$$

This formula determines the maximum average distribution revenue (**$MADR_t$**) that ETSA Utilities can recover per unit of sales for each customer group *j* for the regulatory year *t*. The MADR is derived by escalating the then current average distribution revenues for each customer group (**$ADR_{t-1,j}$**) for the change in the March quarter **CPI** less the **X** factor.

The adjusted average distribution revenues (**$ADR_{t,j}$**) are then multiplied by the forecast sales for each customer group *j* for the regulatory year *t* (**$FDE_{t,j}$**). This results in a notional revenue requirement that ETSA Utilities can recover in the regulatory year *t*, which is then summed across all customer groups. This revenue is then adjusted for the following factors:

- K_t – which corrects for differences in the revenue collected by ETSA Utilities as a result of proportional shifts between forecast sales quantities and actual sales quantities (as opposed to differences in total sales);[169]
- Q_t – which corrects for differences in the revenue collected by ETSA Utilities as a result of changes between total forecast sales quantities and total actual sales quantities (as opposed to proportional shifts in sales);
- SI_t – which reflects the financial gain or loss received by ETSA Utilities under the service incentive scheme;
- U_t – which reflects the amount of funding provided for undergrounding, pursuant to the undergrounding program established under the *Electricity Act 1996*;
- P_t – which reflects a sharing of the profits earned by ETSA Utilities in unregulated activities utilising prescribed distribution assets;
- EPO_t – which incorporates the impact of the equivalent K_t, SI_t and U_t factors that applied in the previous regulatory period as if the previous regulatory period was part of this regulatory period;
- CPI_t – represents the annual change in the March quarter CPI; and
- X_t – is the real decrease in price that the Commission has determined for this regulatory period, which is equal to 1.3%.

All factors aside from **EPO_t** are expressed in revenue terms. For this reason, the resultant total revenue (once all factors are considered) is divided by total forecast sales on the distribution network (**FDE_t**).

ETSA Utilities is required to submit its forecast average distribution revenue (**$FADR_t$**) for the regulatory year *t*. The **$FADR_t$** is calculated as the product of ETSA Utilities' proposed distribution tariffs and the forecast sales relevant to that tariff (i.e. proposed price

[169] This adjustment is required to ensure that ETSA Utilities recover the MADR that was allowed for in this draft price determination. The MADR is an average of the ADR across each customer group, with the relative weights applied in calculating the MADR being the forecast sales for each customer group. Differences between the forecast and actual mix of sales for each customer group will affect the actual MADR collected by ETSA Utilities. For example, the actual MADR collected by ETSA Utilities will be higher if sales to high price customer groups (such as residential customers) are relatively higher than forecast at the time $MADR_t$ was set. Such an outcome would, if not corrected, would result in ETSA Utilities correcting more revenue than allowed for by this draft price determination (and vice versa if actual sales were proportionately lower than forecast).

multiplied by forecast sales). The resultant revenue is then divided by forecast sales across all customer groups (**FDE_t**) to derive the **$FADR_t$**.

The revenue control obligation requires that **$FADR_t$** is equal to or less than **$MADR_t$**, which is expressed as follows:

$$FADR_t \leq MADR_t$$

$$FADR_t = \frac{FDR_t}{FDE_t}$$

where:

- ***FDR_t*** – is the forecast distribution revenue from prescribed distribution services for regulatory year t calculated using distribution tariffs submitted to the Commission for approval; and
- ***FDE_t*** – is as described earlier.

12.5.1 Escalation using the (CPI)(1-X) approach

There are two common forms of the CPI-X formula, which are:

- Price change < (CPI - X); or
- Price change < (CPI)(1 - X)

The difference between the two formulae is very slight, particularly if the setting of the X factor takes account of the differences between the formulae. That is, if the second formula is used, the required reduction in prices (X) should be smaller than if the first formula was used because, for the same X factor, the second formula will imply a larger drop in prices (the difference being the interactive term, CPI x X).

While the first formula was used in the EPO in the 2000-2005 regulatory period, the second formula vastly simplifies the financial modelling. In particular, as the (CPI) term can be factored out of prices, the use of the second formula permits all modelling to be undertaken in constant price (real terms), and for inflation to be introduced in the price control formula.

The Victorian ESC and the ACCC have both adopted the second formula for the reasons set out above. The second formula has been adopted in this determination.

12.5.2 Correcting for forecast errors in total sales (Q)

The derivation of the average distribution revenues set out in Table 12.1 and associated price path is based on the ESIPC sales forecasts. These sales forecasts are used to divide the notional revenue requirement for each customer group by forecast sales for that group.

The actual sales that are realised by ETSA Utilities over the 2005-2010 regulatory period will differ from the ESIPC sales forecasts. The financial impact on ETSA Utilities will depend on the magnitude of the forecast error and whether forecasts understated or overstated actual sales.

Such forecast sales risks are an inherent feature of the average revenue form of regulation. However, the Commission does not consider it appropriate that ETSA Utilities (or customers) be fully exposed to this financial risk over the 2005-2010 regulatory period, as has been the case in the 2000-2005 period.

Generally speaking, ETSA Utilities receives more revenue than expected under this draft price determination if its actual sales are greater than forecast sales. Customers are in turn paying more for distribution services than would otherwise be the case had the higher than expected sales been incorporated into the determination of the average revenue controls (as a higher divisor would reduce the $/MWh controls).

In contrast, ETSA Utilities would receive less revenue than expected if actual sales were lower than forecast, and customers would be paying less for prescribed distribution services than would otherwise be the case. This issue is of particular concern given that ETSA Utilities' capital expenditure requirements are more closely linked to total network demand (MW) than sales (MWh).

Over the 2000-2005 regulatory period, ETSA Utilities' actual sales have tended to be below those forecast under the EPO, particularly over the latter parts of the regulatory period.[170] This is due predominantly to the impact of weather on actual sales and to the retail price increases experienced at the commencement of full retail contestability (FRC) on 1 January 2003.

The Commission does not consider that ETSA Utilities (or customers) should bear the full financial risk of such external factors, and notes that these factors are extremely difficult to incorporate into forecasts. The Commission also notes the inconsistency between the incentives generated under average revenue regulation and its demand management program (see chapter 4).

The Commission has therefore incorporated the $\mathbf{Q_t}$ factor into the average revenue control formula, which seeks to reduce the financial risks faced by ETSA Utilities of forecast sales errors. The $\mathbf{Q_t}$ factor provides ETSA Utilities with a revenue increase or decrease depending on whether actual sales are lower or higher than the sales forecasts.

The $\mathbf{MADR_t}$ is increased if actual sales are lower than forecast for the previous regulatory year. This is to provide some compensation to ETSA Utilities for the revenue loss it experienced from lower than expected sales. The $\mathbf{MADR_t}$ is

[170] As outlined in chapter 5 ETSA Utilities experiences no growth in sales between 2002/03 and 2003/04.

decreased if sales are higher than expected, such that the price paid by customers is less than would otherwise be the case.

There are two important characteristics that apply to the operation of the $\mathbf{Q_t}$ factor.

The first relates to a tolerance band whereby no increase or decrease in $\mathbf{MADR_t}$ occurs for very slight changes in sales. The Commission believes that ETSA Utilities should be subject to a degree of sales variation that is inherent in average revenue regulation. The Commission has decided that a reasonable tolerance band is +/- 0.5% of forecast sales.[171]

The $\mathbf{Q_t}$ factor has been developed such that no change to $\mathbf{MADR_t}$ occurs to reflect the financial impact of actual sales falling within +/- 0.5% of the forecast sales for a particular regulatory year. For example, if sales were 1% higher than expected, then the change in $\mathbf{MADR_t}$ would be based on 0.5%, which is the incremental change in sales from the + 0.5% tolerance band (i.e. 1% less 0.5%).

The $\mathbf{Q_t}$ factor also incorporates a sharing ratio to determine the extent that any revenue increase or decrease is retained by ETSA Utilities. The sharing ratio is set such that ETSA Utilities retains 85% of the total revenue impact of any difference between actual and forecast sales for a customer group.

For example, assume that ETSA Utilities' sales are higher than forecast, such that the revenue received is higher than expected under this draft price determination. ETSA Utilities will retain 85% of this benefit and 15% of the additional revenue is returned to customers by reducing $\mathbf{MADR_t}$ for the next regulatory year (and vice versa for lower sales).

The $\mathbf{Q_t}$ factor therefore works in the following way:

- the incremental difference between actual sales and forecast sales is calculated, net of the 0.5% tolerance band, for each customer group;
- the resultant sales amount is then multiplied by the average revenue control for each customer group;
- this is summed across all customer groups to calculate a total revenue impact;
- the total revenue is then multiplied by 15% to calculate the quantum of the $\mathbf{Q_t}$ factor; and
- this amount is included into the average revenue control formula.

12.5.3 Profit sharing mechanism (P)

As mentioned in Chapter 2, the Commission has introduced a profit sharing mechanism that allocates a share of the profits that ETSA Utilities can earn from excluded and unregulated services utilising prescribed distribution assets in a

[171] A band of +/- 0.5% accounts for around 50 GWh.

regulatory year. The $\mathbf{P_t}$ factor reflects a share of the revenue earned by ETSA Utilities using the prescribed assets (i.e. the distribution poles and wires).

The Commission decided that a 40% share of ETSA Utilities' pre-tax annual profits earned from the service of providing access to prescribed assets will be treated as prescribed revenue. An annual adjustment to the maximum average distribution revenue will be made each year, resulting in a one year lag in the implementation of the scheme.

12.5.4 Transitional factors

Chapter 7 of the EPO sets out the factors that the Commission must have regard to in making a price determination for the 2005-2010 regulatory period. This includes the need to take into account for 2005/06:

- the value of any correction factors which account for forecast errors in the sales mix (defined in the EPO Formula Schedule as KD_t) that would have applied if that year had been part of the previous regulatory period;
- the value of that part of the undergrounding factor that reflects the removal of overhead lines and poles (defined in the EPO Formula Schedule as LR_{t-1} in the definition of the undergrounding factor) that would have applied if that year had been part of the previous regulatory period; and
- the value of the retained performance incentive revenue allowance (defined in the EPO Formula Schedule as RPI_t) at the end of the previous regulatory period.

Based on the EPO requirement, the Commission has included in the revenue control formula an allowance to reflect the full value of any revenue that would have otherwise been recovered by ETSA Utilities had 2005/06 and 2006/07 been part of the previous regulatory period.

The EPO only requires the Commission to have regard to these factors for 2005/06. However, the impact of the EPO correction factor has a lag of two years before its impact is fully realised. The Commission intends to apply each formula in the same manner as it is currently applied under the EPO. This explains why the EPO factor applies for the first two years of this regulatory period.

For the same reason, it will be necessary to make adjustments to the distribution tariffs in the future regulatory period (i.e. 2010 to 2015) that flow from this draft price determination. Although the Commission has generally avoided fettering the decisions of future regulators, in this case it is unavoidable in order for the schemes put in place in the current determination to work effectively.

Therefore, the Commission requires that the future price determination commencing on 1 July 2010 should have regard to the need to incorporate the various factors that have a lagged effect, which includes the $\boldsymbol{K_t}$, $\boldsymbol{SI_t}$, $\boldsymbol{U_t}$ and $\boldsymbol{P_t}$

factors defined above (Schedule 3 of the draft price determination shows the lagged effect of these variables).

These factors will each influence the revenue that ETSA Utilities will be entitled to recover in the 2010-2015 regulatory period. The Commission intends for these factors to be applied in a similar manner to their application under this draft price determination, as set out in the Formula Schedule of the EPO.

12.5.5 2005/06 distribution tariffs

Some of the EPO transitional factors described in section 12.5.4 are determined using information that is not available until after the Commission releases its final price determination, which is due to be released at the end of March 2005. The final price determination will not be able to include the actual 2005/06 distribution tariffs.

Likewise, the average revenue controls for each customer group determined under the draft price determination (as shown in section 12.3) will need to be adjusted by the change in the March quarter CPI.

For these reasons, the final price determination will only show indicative tariffs that will apply for 2005/06. ETSA Utilities will be required to submit an application to determine the distribution tariffs in a manner that is consistent with the revenue control formula. This statement is due no later than 40 business days prior to 1 July 2005 (see section 12.8 for a discussion on the annual tariff adjustment process).

12.6 Tariff rebalancing control

The average revenue control formula determines the amount by which the average revenue controls are allowed to change on a yearly basis. Once this adjustment has been made, ETSA Utilities is required to determine its distribution tariffs in a manner that is consistent with the average revenue controls.

In developing its distribution tariffs, ETSA Utilities will also be required to comply with a secondary control, which is referred to as the tariff rebalancing control. The tariff rebalancing control limits the amount by which ETSA Utilities' distribution tariffs can change from year to year.

The primary purpose of the rebalancing control is to prevent large changes in tariffs for specific groups of customers. This is because the tariff rebalancing control limits the amount by which a tariff component can increase in real terms (i.e. above the annual change in the CPI) in any given year.

Clause 6.14.4 of the NEC requires the tariff rebalancing control to be consistent with any applicable revenue/price cap that applies. An important part of any rebalancing control is that it does not prevent ETSA Utilities from recovering the revenue that it is entitled to recover pursuant to the average revenue control formula.

The tariff rebalancing control should also provide ETSA Utilities with some flexibility to change its tariffs over the regulatory period. For example, flexibility might be required to allow ETSA Utilities to transition to cost reflective tariffs over time in order that appropriate price signals are passed onto customers.

The rebalancing control adopted by the Commission in this draft price determination applies only to the distribution part of the tariff and not the transmission part of the tariff. This is because the NEC requires that locational pricing signals be passed through to customers. The Commission does not intend for its rebalancing control to restrict ETSA Utilities' ability to meet this NEC requirement.[172]

The tariff rebalancing control will not apply to the change in ETSA Utilities' distribution tariffs between 2004/05 and 2005/06 as a result of the final price determination. That price change reflects the one-off adjustment that must be made to ETSA Utilities' distribution tariffs in order to comply with the average revenue controls set by the final price determination (see section 12.3).

12.6.1 Choice of Rebalancing Control

The tariff rebalancing control can take one of three forms: an annual allowable percentage increase in distribution charges; an annual dollar amount (either to the average annual bill or a tariff component); or a combination of the two.

The benefit of a percentage based rebalancing control is that it represents a proportionate financial impact on customers across customer groups. A disadvantage of a percentage based rebalancing control is that it could potentially create large price shocks to some customers within the same tariff category.

The advantage of applying a dollar amount is that it can avoid the potential for certain customers within a customer group from being disadvantaged. A predetermined dollar amount also provides some certainty over the potential impact of tariff changes on customers. However, a fixed dollar amount might not allow the distributor to achieve cost reflectivity and price signalling.

The Commission intends to allow each distribution tariff component to vary by a fixed percentage amount and the residential supply charge to change by no more than a fixed dollar amount. This approach will provide flexibility for ETSA Utilities to adjust its distribution tariffs while protecting smaller customers from undue increases in the supply charge.

[172] Moreover, the Australian Competition and Consumer Commission is scheduled to make a price determination in respect of ElectraNet SA's transmission tariffs to apply from 1 July 2008. This could have the impact of changing the manner by which such locational pricing signals are provided.

12.6.2 Determining the size of the rebalancing control

The main consideration of the Commission in determining the size of the rebalancing control was that the control should:

- provide sufficient flexibility to ETSA Utilities to adjust its distribution tariffs while ensuring no large price shocks are experienced by customers; and
- allow ETSA Utilities to set its distribution tariffs in a manner that allows it to recover the revenue pursuant to the average revenue control formula.

The Commission undertook an assessment of the possible average revenue implications that could potentially arise under the average revenue control. This included assuming that ETSA Utilities was permitted to recover the maximum financial reward permitted under the service incentive scheme discussed in chapter 3.

The Commission also assessed the amount of rebalancing that would have been required in the 2000-2005 period under the assumption that certain factors were the same as those set down for the 2005-2010 regulatory period. This included the lower X factor of 1.3% relative to the X factor of 2.73% that applied in the current regulatory period and the change in the financial incentive available under the service incentive scheme.

The Commission determined, as part of this assessment, that a real increase in tariffs of 2.5% above the annual change in the CPI could potentially be required under certain conservative assumptions. The Commission has therefore allowed for a rebalancing constraint on distribution tariffs of CPI + 2.5% (or a real increase in tariffs of 2.5%) per annum.

The Commission has also decided to only apply the dollar amount constraint to the supply charge of residential customers. This is because such customers are most vulnerable to changes in the supply charge stemming from rebalancing, particularly those residential customers on low incomes.

The Commission has determined that the supply charge of a residential distribution tariff cannot increase by more than $5 per year. The Commission considers that such a control provides a reasonable balance between protecting low income earners from price movements while providing some flexibility to ETSA Utilities to adjust its distribution tariffs over time.[173]

The amount of flexibility provided to the distributor under the rebalancing control should also be considered in conjunction with any X factor that applies to the revenue/price control. As previously mentioned, the X factor represents an amount by which tariffs can change in real terms over the regulatory period.

[173] This is based on the assumption that low income residential customers have low consumption levels, and that at low consumption levels the supply charge makes up a relatively large proportion of the annual bill. Therefore, by limiting the increase in the supply charge to no more than $5 per annum, the Commission is protecting low income small users from relatively larger price increases compared to those residential customers with high usage.

This implies that the flexibility provided to ETSA Utilities to adjust its tariffs over the regulatory period is the sum of the rebalancing control plus the X factor. The joint impact of both factors allows ETSA Utilities to increase its tariff components by no more than 3.8% (i.e. 2.5% + 1.3%), aside from the additional $5 per annum constraint applied to the residential supply charge.

12.7 Principles for structuring tariffs

In consultation with ETSA Utilities, there will be some changes in the structure of ETSA Utilities' distribution tariffs to apply from 1 July 2005. These revised tariff structures have been set with reference to the pricing principles described earlier in this chapter.

Firstly, no distribution tariff component that applies to small customers from 1 July 2005 will be permitted to increase by an amount that is greater than the most recent change in the CPI. This has been decided in response to the impact on small customers of the significant increase in electricity prices since the onset of full retail contestability from 1 January 2003.

ETSA Utilities has also proposed to introduce a 'step' usage charge as part of the residential tariff, such that a lower usage charge applies for consumption up to and including 4 MWh per year relative to consumption greater than 4 MWh per year. The lower charge applies equally to all residential customers for their respective usage up to the 4 MWh limit. The higher charge will only apply to those customers that use in excess of 4 MWh per year.[174]

The Commission considers that the introduction of a step charge in the distribution tariff structure provides benefits to all residential customers. This is because all customers will receive a lower usage charge for consumption below the 4 MWh threshold. A fixed (supply) charge will continue to apply for residential customers.

ETSA Utilities has also indicated that, after reviewing the costs of metering, a reduction in the difference in supply charges across small customers is appropriate. This is because the metering requirements for small customers are similar. The Commission has reviewed the metering cost information provided by ETSA Utilities and accepts ETSA Utilities' proposal.

ETSA Utilities also proposed to eliminate the supply charge for the controlled load (hot water) distribution tariff, leading to a relatively large decrease for customers with small usage in controlled load. The Commission considers that such an initiative might encourage more customers to use electricity in controlled, off-peak periods.

ETSA Utilities has amended the structure of the small business peak/off-peak (2-rate) tariff by introducing a step usage charge for the peak component of the tariff. This step charge is such that consumption for the first 20 MWh consumed during the peak period is at a higher rate than consumption thereafter.

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[174] Average residential consumption is around 5 MWh per year.

However, ETSA Utilities has also proposed a significant reduction to the supply charge, which will benefit the smaller end of the market. In particular, this initiative will provide a benefit to farmers by reducing some of the costs for those sites that have multiple small two-rate supply points.

ETSA Utilities' proposed small customer distribution tariffs, including the residential, controlled load and small business tariffs, are set out in Chapter 14. This chapter describes the customer impact of the new small customer distribution tariffs for 2005/06 relative to the current tariffs.

With regard to large customers, the focus has been on providing stronger pricing signals to achieve better demand management. This is primarily undertaken for customers currently on demand tariffs, whereby savings can be achieved by improving power factor. ETSA Utilities has indicated that it intends to transition customers away from kW based demand tariffs towards kVA based demand tariffs.

This initiative is consistent with the Commission's demand management initiatives in chapter 4.

12.8 Annual tariff adjustment process

Part E of the NEC describes the manner by which the distributor can change its distribution tariffs each year. By exercising its discretion under clause 6.11(e) the Commission has also decided to substitute the NEC annual tariff adjustment approach with its own approach.[175]

For each regulatory year, ETSA Utilities will be required to submit to the Commission a statement proposing tariffs to apply for that regulatory year. The statement must be submitted at least 40 business days, but not more than 60 business days before the start of that regulatory year.

The statement must contain ETSA Utilities' proposed tariffs for the relevant regulatory year and the proposed tariff components for each of the proposed tariffs. The statement must also demonstrate that the proposed tariffs and tariff components comply with the relevant parts of this draft price determination and must explain the medium term tariff strategy adopted by ETSA Utilities in developing the proposed distribution tariffs.

ETSA Utilities must publish the statement on its website within 5 business days of providing it to the Commission.

The Commission will not approve the statement (and hence the proposed distribution tariffs) unless it is satisfied that the statement sets out the proposed tariffs and tariff components, that the proposed tariffs and tariff components comply with the pricing principles in the pricing principles schedule and the relevant principles and formulae in the formula schedule, and it is satisfied with all relevant forecasts and estimates contained in the statement.

[175] See clauses 6.14.5 and 6.14.6 of the NEC.

In addition, the Commission must be satisfied that the values of any correction factors that correct for differences between forecast, estimated and actual sales are consistent with the principles in relation to forecasts and estimates of demand, energy and revenue and the relevant principles and formulae set out in the Formula Schedule. The Commission must also be satisfied that the statement explains the medium term tariff strategy adopted by ETSA Utilities in developing the proposed distribution tariffs for the regulatory year.

If the Commission approves a statement, it will notify ETSA Utilities within 20 business days of receiving the statement and publish a notice on its website .

If the Commission does not notify ETSA Utilities within that time, it will be deemed to have approved the statement with effect from the 21st business day after the statement was received.

Where the Commission does not approve a statement, it may allow ETSA Utilities to replace the statement within a time specified by the Commission. ETSA Utilities will be permitted to submit only one such replacement statement during an annual tariff adjustment process. The ordinary approval processes apply thereafter.

Once the statement or replacement statement has been approved or deemed to have been approved, the tariffs will apply from the start of the next regulatory year.

If ETSA Utilities does not provide a statement to the Commission or a (replacement) statement is provided but not approved by the Commission, then the Commission may re-set the relevant tariffs on behalf of ETSA Utilities. In this event, the Commission is required to notify ETSA Utilities in writing of the tariffs, notify the Treasurer (the Minister responsible for the ESC Act) and the Minister responsible for the Electricity Act, and publish a notice in the Gazette and a newspaper circulating generally in the State. The distribution tariffs will take effect from the start of the next regulatory year.

12.9 Altering, Introducing and Closing Distribution Tariffs

For various reasons, ETSA Utilities may, at times other than when tariffs are annually adjusted, seek to alter distribution tariff components, or introduce or close a distribution tariff. The requirements on ETSA Utilities should it seek to alter a distribution tariff component, are set out in clause 3.3 of Part B of this draft price determination.

Clause 3.4 of Part B sets out the approval criteria to be followed by the Commission when assessing a statement submitted by ETSA Utilities under clause 3.3.

The processes ETSA Utilities must follow when seeking to introduce a new distribution tariff or close an existing distribution tariff are described in clauses 3.5 and 3.6 of Part B, respectively.

The Commission's approval process in respect of the introduction and closing of distribution tariffs is provided in clause 3.7 of Part B.

13 REGULATED PASS-THROUGH

13.1 Regulated Pass Through

The EPO contains a scheme which permits the pass-though of certain unexpected changes in the costs of providing prescribed distribution services to customers arising from the occurrence of specified exogenous events. The effect of the pass-through mechanism is that while average revenue controls remain as set ex ante, should specified events occur which move ETSA Utilities' costs away (positively or negatively) from those controls, tariffs are permitted to be adjusted (up or down) so that ETSA Utilities is placed in the same position as it would have been "but for" the occurrence of that event.

It is important to note two matters in relation to the regulated pass-through mechanism.

First, it does not apply to all unforeseen events or correct all forecast errors. It only has effect in relation to certain specified events that are outside of the control of ETSA Utilities and that cause a change (either positive or negative) to its costs of providing prescribed distribution services.

Secondly, while the pass-through mechanism is designed to place ETSA Utilities in the same position as it would have been in "but for" the occurrence of the defined event, that result is not achieved through an adjustment to the average revenue controls contained in the EPO. Rather, the pass-though mechanism allows for the imposition of an "add-on" amount to tariffs, such that customers will either pay more (under a positive pass-through) or less (under a negative pass-through) for prescribed distribution services than would otherwise be the case.[176] In other words, the financial impact of the defined unforeseen event on ETSA Utilities is required, under the EPO's regulated pass-through mechanism, to be "economically neutral": it is to be no better or worse off due to the occurrence of that event.

13.1.1 Outline of the current EPO pass-through mechanism

Chapter 6 of the EPO sets out the detail of the regulated pass-through mechanism which is currently in place. Clause 6.1(b) specifies the complete list of events which can trigger the operation of the mechanism:

- *A change in taxes event*: a change in, the removal of, or the imposition of a tax to the extent that the change, removal or imposition applies to the provision of prescribed distribution services by ETSA Utilities or to the provision of goods and services to ETSA Utilities as a result of which ETSA Utilities incurs materially higher or lower costs in providing prescribed distribution services than it would have but for the occurrence of the event.

[176] Noting that the variations to tariffs arising from the pass-through amount do not need to comply with the formula schedule of the EPO: EPO, clause 6.7(a)(ii).

- *A service standards event*: a decision made by a regulatory authority (eg, the Commission, NECA, NEMMCO, ACCC, ESIPC, OTR) that has the effect of imposing new minimum standards on ETSA Utilities, or requiring ETSA Utilities to perform new functions as part of prescribed distribution services, or substantially varies the manner in which ETSA Utilities is required to perform any functions forming part of prescribed distribution services, as a result of which ETSA Utilities incurs materially higher or lower costs in providing prescribed distribution services than it would have but for the occurrence of the event.
- *A settlements residue event*: the allocation and distribution of settlements residue to ETSA Utilities under the NEC or the pass through to ETSA Utilities of a pass-through amount resulting from a settlements residue event affecting ElectraNet SA.
- *A network event*: a change in the way or rate at which a charge for the use of an interstate network or interconnector is calculated, or the removal or imposition of such a charge, as a result of which ETSA Utilities incurs materially higher or lower costs in providing prescribed distribution services than it would have but for the occurrence of the event.
- *A regulatory reset event*: means a price determination made by a relevant regulator in relation to transmission services that takes effect after 31 December 2002 but before 30 June 2005 as a result of which ETSA Utilities incurs materially higher or lower costs in providing prescribed distribution services than it would have but for the occurrence of the event.

If, in the view of ETSA Utilities, one of these events has occurred, it may apply to the Commission seeking the Commission's approval to pass-through an amount (higher or lower) in relation to the amounts which ETSA Utilities is ordinarily entitled to charge for prescribed distribution services.[177] The application to the Commission is required to provide significant detail on the nature and occurrence of the event, describe how the event impacts financially (positively or negatively) on the provision of prescribed distribution services and the manner in which ETSA Utilities proposes to apply the pass-through amount.[178]

Upon receipt of an application from ETSA Utilities, the Commission is required to determine whether the pass-through event occurred. If it concludes that an event did occur, the Commission must thereafter determine the:

- amount of the pass-through;
- basis on which the pass-through amount may be applied to customers; and

[177] EPO, clause 6.2(a).

[178] EPO, clause 6.2(b).

- date from, and the period over which, the pass-through amount is to be applied.[179]

There is a risk that certain pass-through events may occur which would provide customers with price changes which are not the subject of a pass-through application by ETSA Utilities. In such cases, the Commission is empowered to require ETSA Utilities to pass through an amount determined by the Commission, on a basis and over a period set by the Commission.[180]

Importantly, the EPO specifies various factors which the Commission must take into account in making a decision on a pass-through application lodged by ETSA Utilities or in deciding to require ETSA Utilities to pass-through an amount to customers.

The key point is that the Commission must ensure that the financial effect on ETSA Utilities associated with the pass-through amount concerned is economically neutral. [181]

The other factors that are to be taken into account are set out in clause 6.5 and include:

- the relative amounts of prescribed distribution services supplied to each customer;
- the time cost of money for the period over which the pass-through amount is to be applied;
- the basis on and period over which the pass-through amount is to be applied;
- the financial effect on ETSA Utilities associated with the provision of prescribed distribution services directly attributable to the pass-through event and the time at which the financial effect arises;
- any pass-through amount applied which related to a previous pass-through event in the same category (eg, a previous change in taxes event), which resulted in ETSA Utilities recovering an amount either more or less than the financial effect on ETSA Utilities of that previous pass-through event; and
- any other factors which the Commission considers relevant.[182]

If the Commission approves or requires a pass-through, ETSA Utilities is required to notify customers of the pass-through amount and apply the approved or required pass-though amount as specified by the Commission.[183]

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179 EPO, clause 6.2(a)(i), (ii) and (iii).

180 EPO, clause 6.4.

181 EPO, clause 6.5(b).

182 The complete list of factors is set out in clause 6.5 generally.

183 EPO, clause 6.6.

It is important to note that the pass-through amount is not added into the average revenue controls; it is simply an amount which sits alongside those controls only for as long as is required to return ETSA Utilities to a economically neutral position. If it were to be added into the average revenue controls, that might result in a permanent increase or decrease in prices for prescribed distribution services and as such would not be correcting the effects of an event. This much is evidenced in the terms of clause 6.7, which provides that any pass-through amounts are not to be taken into account in deciding ETSA Utilities' revenues, tariffs or individual tariff components under the EPO's Formula Schedule, nor in deciding whether ETSA Utilities' tariffs or individual tariff components comply with the Formula Schedule's principles.

13.1.2 Adoption of a pass-through mechanism in the price determination

It is the Commission's view that it is appropriate to include a mechanism within the price determination which is largely consistent with that contained in the current EPO.

Clause 6.10.3(e) of the NEC sets out various principles which guide the Commission in the making of this price determination. Clauses 6.10.3(e)(3) and (6) provide directly relevant guidance to the Commission in terms of the adoption of the pass-though mechanism:

> *The regulatory regime to be administered by the Jurisdictional Regulator must be consistent with the objectives outlined in clause 6.10.2 and must also have regard to the need to:*
>
> *(3) take account of and be consistent with the allocation of risk between Network Owners and Network Users;*
>
> ***
>
> *(6) provide reasonable certainty and consistency over time of the outcomes of regulatory processes having regard to:*
>
> *(i) the need to balance the interests of Network Users and Network Owners;*
>
> ***
>
> *(iii) the need to minimise the economic cost of regulatory actions and uncertainty.*

The two broad themes arising from those clauses are that regulatory decisions should provide reasonable certainty and consistency over time, which the retention of a pass-through mechanism will achieve, and to account for risk allocation between ETSA Utilities and customers.

With regard to this latter point, it is in one sense arguable that, as the effect of the pass-through mechanism is to provide a guarantee of economic neutrality to ETSA Utilities on the occurrence of specified events, all of the financial risk arising in relation to these events is transferred to customers. While such an argument is sustainable to a degree, the Commission notes that it is the particular nature of the

specified events which makes the financial risk allocation appropriate in those cases. In the case of other events or occurrences, however, it is not appropriate that customers bear all the financial risk: such risks should either be borne by ETSA Utilities or shared as between ETSA Utilities and customers. Such other events and occurrences are therefore treated differently to pass-through events (for example, the Q factor described in Chapter 11).

The Commission also notes that the effect of clauses 6.10.2(g), (i), (j) and (k) of the NEC, which are called up by clause 6.10.3(e)(3), is to indicate to the Commission that the adoption of a pass-through mechanism in similar terms to that contained in the current EPO is consistent with the requirements of the NEC. Those clauses require the Commission's price determination to seek to achieve the following outcomes:

- Reasonable recognition of pre-existing policies of governments which are distribution network owners regarding distribution asset values, revenue paths and prices (noting that at the time the EPO was made by the former Treasurer, the South Australian distribution business was a statutory corporation);
- Reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions;
- Reasonable certainty and consistency over time of the outcomes of regulatory processes, recognising the adaptive capacities of Code participants in the provision and use of distribution network assets; and
- Reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of distribution network owners, distribution network users and the public interest.

Bearing in mind these considerations, and noting the workings of the current pass-through scheme as described in section 13.1.1, the Commission is of the view that it will continue to utilise the mechanism of a pass through scheme to account for a defined set of exogenous events which have the effect of materially increasing or decreasing the costs to ETSA Utilities incurred in providing prescribed distribution services.

In adapting the current pass-through model for the price determination, the Commission proposes that an efficiency carryover mechanism should be included. The inclusion of an efficiency carryover mechanism will provide a continuous incentive to ETSA Utilities to achieve efficiencies in relation to the pass-through events and will provide regulatory consistency in the treatment of revenues.[184]

[184] EPO, clause 7.2(h).

13.1.3 Pass-through events

The Commission has considered each of the current trigger events specified in the EPO and has concluded that aside from settlements residue events and network events, those trigger events remain relevant for the 2005-2010 regulatory period and will be adopted in the price determination.

In relation to settlements residue events and network events, when ElectraNet SA's revenues were regulated under the EPO (up until December 2002), it was permitted to pass through the impact of settlements residues and network payments paid to interstate transmission companies. ElectraNet SA revenues are now regulated under a regulatory regime imposed by the ACCC in accordance with the NEC, under which those matters are rolled-up within the total average revenue allowances in place. As a result, it is no longer necessary to continue to pass-through those amounts.

The Commission has considered whether any new pass-through events should be included for the price determination. The Commission has considered three such additional classes: force majeure events, extraordinary circumstances events and major projects events.

Consideration of force majeure events

The concept of force majeure arises from the law of contract and is based on contractual agreement between two parties that, in a circumstance beyond the control of a party to the contract, the affected party is able to escape liability for failing to perform the contract as a result of the circumstance.[185] The circumstances encompassed by force majeure are broader than the ordinary common law categories of "acts of God", and include human acts (such as war, strikes and machinery breakdowns) as well as natural acts (such as earthquakes, floods, storms).

The Commission does not consider that force majeure, as a concept, is necessarily of ready application to the price determination, as it is based in contract law. The suspension of rights and obligations as between customers and ETSA Utilities is already provided for under the Electricity Distribution Code and the standard Connection and Supply Contract in place as between those parties through section 36 of the Electricity Act.[186]

It is difficult to see how or why the occurrence of a force majeure event, permitting ETSA Utilities to suspend its obligations to provide prescribed distribution services, should translate into an event precipitating changes to the costs associated with the provision of those services.

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[185] See, for example, *Matsaukis v. Priestman & Co* [1915] 1KB 681.

[186] Electricity Distribution Code (EDC/04), Part A clause 1.13, Part B Standard Connection and Supply Contract clause 24.

The Commission is not, therefore, minded to include a force majeure pass through event in the price determination.

Consideration of extraordinary events

Perhaps more appropriate for the price determination would be the inclusion of an extraordinary events pass-through. The Commission considers that such a concept has more relevance than does force majeure, insofar as incentive-based regulation requires ex ante controls and, necessarily, ex ante assumptions as to the "state of the world" across the regulatory period.

While the ordinary ebb and flow of commercial and natural circumstances across a regulatory period will dictate that the assumptions and forecasts set ex ante are highly unlikely to come to pass in every detail, it needs to be recognised that there may be degrees of departure. In the case of departures deriving from the occurrence of new intervening events after the time of making the price determination which are of such magnitude as to completely disturb the basis of the "regulatory bargain" implicit in the price determination, it may be appropriate to deal with these events by way of a pass-through (be it positive or negative).

On further analysis, however, the identification of such events is a task not amenable to ex ante precision. It would appear on the face of things that should such an event occur, it would provide reason to re-open the price determination in entirety rather than attempting to accommodate what are likely to be substantial financial impacts in pass-through amounts (recalling that pass-through amounts need to be considered as separate amounts to those calculated under the average revenue controls). If significant, it could well be that the pass-through amount exceeds the tariffs derived from the average revenue controls, which would be a perverse outcome.

Nevertheless, the Commission is cognisant of the fact that such a complete revision is not permitted by the NEC. The imperative arising from the combined operation of clauses 6.10.5(c) and 6.10.5(e) is that a price determination must last for at least three years and can only be re-opened before the expiry of the three years in the event that the price determination was based on false or materially misleading information or there was a material error in the setting of the determination. In the latter circumstance, the prior written consent of parties affected by any proposed re-opening is also required before the re-opening is permitted. Further, it is to be noted that one of the factors to which the Commission must have regard in constructing the price determination is the on-going commercial viability of the distribution industry.[187] The Commission has therefore reached the conclusion that an extraordinary events pass-through is appropriate for the 2005-2010 regulatory period.

[187] NEC, clause 6.10.5(d)(10), see also *ESC Act*, section 6(1)(b)(vi), noting that this latter section is subordinate to, although coordinate with, the provisions of the NEC.

While it may be simple conceptually to consider pass-through amounts relating to extraordinary events, it is difficult to define what "extraordinary" might mean in practice. Arguably "extraordinary" could, in its ordinary meaning, include sudden and dramatic changes to weather patterns or the accelerated obsolescence of the technologies utilised in the distribution network. Clearly, not all of these events should trigger a pass-through.

The Commission has therefore formed a view that while an extraordinary events pass-through is to be permitted, it should retain the power to define the scope and purview of such an event, having regard to all relevant legislative factors (the NEC, the EPO, the Electricity Act and the ESC Act). ETSA Utilities will be entitled to make a case to the Commission that an extraordinary event has occurred which, assessed against the legislative factors, is demonstrably justification for a positive or negative pass through. If the Commission agrees with that submission (or, in the absence of such a submission forms a view of its own motion that such an event has occurred) based on its considerations of all relevant factors, then the Commission can also approve an appropriate pass through amount.

The Commission is aware of the risks inherent in such an approach. However, having regard to the potential magnitude of risk associated with the NEC's prohibition on any reopening of a price determination and bearing in mind the degree of control to be exercised by the Commission, the Commission considers that its proposal reflects an appropriate balance of all relevant interests.

Consideration of major projects events

In making a price determination, and thereby in determining average revenues and average revenue controls for the 2005-2010 regulatory period, the Commission is required to establish allowable operating and capital expenditure benchmarks for ETSA Utilities for the period. As these costs are recovered from consumers through distribution use of system charges (dollar-for-dollar in the case of operating expenditure and as a percentage return on and of assets in the case of capital expenditure), it is important that the Commission does not materially over or under set these benchmarks.

In considering submissions made by ETSA Utilities as to the appropriate benchmarks to be set, the Commission identified a number of major capital expenditure projects relating to requirements for new transmission connection points in the Adelaide metropolitan region which have a potentially significant financial impact on capital expenditure benchmarks. In these cases, there is a degree of uncertainty as to whether the project will be undertaken at all and as to the accuracy of the forecast costs of the project. This uncertainty arises from the fact that the performance of these projects is dependent upon if, when and how ElectraNet SA undertakes upgrades to its transmission network (in accordance with its funding arrangements as set by the ACCC).

In each case, it is noted that the rationale for the project rests on current regulatory obligations. That is not to say that the current regulatory scheme obliges ETSA Utilities to undertake the particular projects. Rather, it is simply to say that the performance of the projects would not be inconsistent with regulatory obligations.

Further, in relation to the quantum of costs for these projects, the Commission notes two matters. The first is that these projects, although being undertaken by ETSA Utilities, are more in the nature of the provision of a transmission service, which would ordinarily (as is the case in other States) be performed by a transmission business. Secondly, while the frequency of occurrence of these projects is lower, the costs associated with each project are higher than would be expected for a distribution network project. The ordinary projects arising in relation to a distribution network are generally frequent and low cost. By comparison, the projects carried out on transmission networks tend to be infrequent but far more capital intensive. These unique sub-transmission projects fall somewhere in the middle of the two.

On one view, the inherent uncertainty in these projects is of such a magnitude as to tend towards exclusion of the events from the capital expenditure benchmarks. Nevertheless, the Commission notes that should the projects be required to go ahead during the period, having been excluded from the setting of the capital expenditure benchmarks, ETSA Utilities will be unable to recover the associated costs (at least until the next regulatory review in 2010). Such an outcome would be inconsistent with the requirements of the NEC, as ETSA Utilities would not be earning a return on otherwise efficient investment.[188]

In light of these matters, the Commission considers that it is appropriate to deal with these major projects through the mechanism of a pass-through. While these events are perhaps not so strictly external to ETSA Utilities as are the other triggers, it is nevertheless true that ETSA Utilities is dependent on an external decision being taken before it knows whether or not the projects will be required.

The Commission would also emphasise the unique nature of the particular sub-transmission connection point projects under consideration as well as the potential for large windfall gains (or losses) for both customers and ETSA Utilities should the projects be funded and not proceed, or not be funded and then proceed during the regulatory period. In each case there would be no sharing of risk: either ETSA Utilities or customers would bear the entire risk of the project until the next price determination takes effect in 2010.

The particular major projects which will be defined by the Commission to be major project events are the connection point projects in the Adelaide Metropolitan region associated with upgrades to the ElectraNet transmission network. PBA

[188] NEC, clause 6.10.5(e)(5).

has provided the Commission with a list of these major sub-transmission projects. These projects are discussed in greater detail in Chapter 7, and are reproduced in the table below.

Table 13.2 Major Connection Point Projects in the Adelaide Metropolitan Area ($Mar 2004, $000)

	2005/06	2006/07	2007/08	2008/09	2009/10
East Terrace 2nd 275kV cable & 275/66kV Transformer	0	0	0	318	481
East Terrace to Hindley St - new 66kV cable	0	0	0	4987	7540

This scheme will require ETSA Utilities, with input from ElectraNet SA, to initiate and undertake studies into the requirement for additional connection point capacity in the major metropolitan area. This study will need to explain the solution developed by ETSA Utilities in conjunction with ElectraNet SA for providing additional connection point capacity to a particular region.

The Commission intends to involve ESIPC as the independent advisor on the prudence of any connection point proposal that ETSA Utilities submits to the Commission.[189] Based on the outcome of this review, the Commission will allow ETSA Utilities to recover the efficient cost of providing the proposed solution.

The Commission also recognises the strong link between the connection point projects and the sub-transmission line projects in terms of increasing network capacity. Any study undertaken by ETSA Utilities will need to refer to how the proposed connection point project impacts the major sub-transmission projects that have been incorporated into expenditure benchmarks.

The Commission intends to consider any application made by ETSA Utilities in reference to a connection point project against the major sub-transmission expenditure approved as part of this price determination to ensure that an optimal solution has been pursued.

The Commission would consider the financial impact of any deferral of a sub-transmission project as a result of any proposed connection point project in making its decision on prudent and efficient expenditure to be recovered by ETSA Utilities. This will ensure that the scheme provides optimal outcomes for both ETSA Utilities and consumers.

As a result, the Commission is of the view that the category of major projects event should be included as a pass-through event in the 2005-2010 price determination.

[189] This role for ESIPC is consistent with its functions as provided for in Division 2 of the Electricity Act 1996.

Consideration of NEC requirements in relation to pass-through events

The Commission has considered the requirements of the NEC in relation to the adoption of the pass-through mechanism. Of note, clause 6.10.2(b)(2), which sets out the required objectives of the distribution service pricing regulatory regime to be administered by the Commission, provides:

> *The distribution service pricing regulatory regime to be administered under Part D of the Code must seek to achieve the following outcomes:*
>
> *(b) an incentive-based regulatory regime which:*
>
> *(2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Distribution Network Owners on efficient investment, given efficient operating and maintenance practices of the Distribution Network Owners.* (emphasis added)

It is the concept of "*on a prospective basis*" which demands attention in relation to the pass-through scheme. The requirement to set the basis of the pricing regime in a prospective manner is a requirement of both the NEC and the EPO, in that an incentive-based approach to distribution service pricing is to be adopted by the Commission. Prospectivity, in the context of incentive-based regulation, implies that all elements of the regulatory scheme are known in advance, such that ETSA Utilities has targets (average revenues) at which it can aim in achieving efficiencies. The impact of amending those targets during the course of the review needs to be considered to ensure consistency with the NEC and the EPO.

It is the Commission's view that while it is arguable that the potential for "at large" changes to be made to revenues during the regulatory period would offend the principles embodied within clause 6.10.2(b)(2), this is not so if the events triggering changes to revenues are clearly defined and known in advance.

The specification of the events means that ETSA Utilities and all other stakeholders know clearly in advance of the potential for changes to revenues should the major connection point projects occur. This has the effect of permitting ETSA Utilities and all other stakeholders to know in advance the effective upper and lower bounds of any change to the revenues arising from the occurrence of these major projects. The Commission also notes that the amounts of revenue recovered under the pass-through scheme are limited to putting ETSA Utilities back into the cost position in which it would have been "but for" the occurrence of the particular event. This position is, in the Commission's view, in accordance with the requirements of 6.10.2(b)(2).

The Commission would also note that the proposal complies with the objectives set out in clause 6.10.2(k), seeking a reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of distribution

network owners, customers and the public interest.[190] It is the Commission's view that, given the potential quantum of costs associated with the pass-through events, for example, the major projects potentially total some $8 million across the 2005-2010 regulatory period, in the absence of a mechanism there would be obvious adverse consequences for all parties, depending on whether or not the event occurs.

The approach adopted by the Commission is similar to that proposed by the ACCC in their draft decision on Regulatory Principles. In this document the ACCC proposed excluding significant but uncertain investments from the revenue cap decisions and reviewing if and when the event arises.[191]

Pass-through events for the price determination

The list of pass-through events for the purposes of the 2005-2010 price determination will therefore be as follows:

- change in taxes events;
- service standards events;
- regulatory reset events;
- extraordinary events; and
- major projects events.

13.1.4 Materiality tests

There is presently a "materiality" test included within the provisions of the EPO, which provides a threshold test which must be met in relation to a pass-through event before it will be considered by the Commission. The Commission considers that such a test should be implemented in the price determination, as it is of the view that it is not appropriate that the mere occurrence of a defined pass-through event, whatever the financial and economic impact, is sufficient to warrant the recovery of a pass-through amount. Such an outcome would be inefficient and, as such, contrary to the principles and objectives of the NEC.

Instead, the Commission considers that only those pass-through events which give rise to a material change in expenditures in a given regulatory year should properly become the subject of a pass-through application from ETSA Utilities. Such a threshold test will ensure efficiencies.

Whilst it would be possible to establish a more specific test than a materiality test, for example, one expressed as a percentage change in either expenditure or

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190 The Commission also notes that a proposal of this nature has been proposed by the ACCC in its "*Statement of Principles for the Regulation of Electricity Transmission Revenues*" (ACCC, 18 August 2004). See, for example, discussion at page x of the Executive Summary.

191 See: ACCC 2004, 'Statement of Principles for the Regulation of Electricity Transmission Revenues', Draft Decision, 18 August 2004. This document is available at the website: www.accc.gov.au.

average revenue allowances, the Commission has formed the view that it is more appropriate to retain the existing subjective test rather than establishing such a bright-line test.

The Commission has reached this view having considered the practical application of a bright-line test, which is likely to prove problematic. For example, if the Commission were to adopt a bright-line test which led to an amount of $5 million being the threshold amount before a pass-through would be considered, there might be an inequity in the exclusion of a $4.9 million dollar project. Further, in that case ETSA Utilities would have an incentive to inflate the costs related to the pass-through event so that the $5 million threshold was passed; the Commission would not wish to establish a regime containing such incentives.

As a matter of principle, therefore, the Commission considers that adopting a materiality test which allows for a better assessment of the merits of each individual case, is to be preferred to the adoption of a more rigid and inflexible bright-line test.

The materiality test to be adopted is that the occurrence of the event must have a material impact (positive or negative) on the costs incurred by ETSA Utilities in providing prescribed distribution services, which impact would not have eventuated but for the occurrence of the event.

14 IMPACT OF THIS DRAFT PRICE DETERMINATION

This section considers the financial impact of this draft price determination on ETSA Utilities' financial position. It also analyses the impact of this determination on residential customers.

14.1 Financial Impact Analysis on ETSA Utilities

In making a price determination, the Commission is required to have regard to the financial viability of ETSA Utilities. For example, clause 6.10.5 (d) (10) & (11) of the National Electricity Code ("the NEC") requires the Commission to have regard to:

> *(10) the on-going commercial viability of the distribution industry; and*
>
> *(11) any other relevant financial indicators.*

This obligation is also to be found in other regulatory instruments such as the EPO and the ESC Act.

Moreover, the Commission considers that ensuring the financial viability of the distribution business is a critical factor in protecting the long-term interests of customers.

14.1.1 Methodology

Use of benchmark financial data

The financial position of the distribution business is considered by looking at the underlying assumptions and benchmarks that have been used in this decision, rather than by using actual financial data for ETSA Utilities. For example, the amount of borrowings by the distribution business is assumed to be 60% of the regulatory asset base (consistent with the benchmark, as set out in 10.6.8 of this determination) not the actual borrowings as a proportion of the book value of the assets.

This analysis is based on a benchmarked credit rating of BBB+ for the prescribed distribution business. It should be noted that ETSA Utilities' actual financial position can and does differ from that assumed in this section (for example, it undertakes activities in addition to the prescribed distribution services and its financial position covers all such activities).

This analysis should not therefore be construed as an analysis of ETSA Utilities' credit rating. Credit ratings agencies conduct a more substantive analysis that review other factors such as the business and operating environments, apart from just the financial ratios. The purpose of this analysis is only to review whether this draft determination compromises the distribution business' current financial position (for prescribed distribution services).

Underlying assumptions

A number of financial ratios are considered by credit rating agencies when conducting an analysis of the credit rating that should be assigned to a business. The Commission has sought to derive some of the common financial ratios used by such agencies. ETSA Utilities provided these ratios and their definitions to the Commission, and the Commission has also independently accessed public available information from such agencies on these measures[192].

In deriving the cost of debt (see section 10.6.8), the Commission has determined that a benchmark rating of BBB+ is appropriate for the distribution business. This is considered to be an investment grade rating. The Commission's analysis looked at the various financial ratios in assessing whether this benchmark credit rating is compromised by the determination made by the Commission.

In assessing a borrower's credit rating, the credit rating agencies assess a wide range of factors in addition to the analysis of financial ratios. The Commission's analysis does not attempt to consider or assess any factors relevant to the distribution business' credit rating other than the likely financial effects of the Commission's determination. The analysis is limited to the 2005-2010 regulatory period.

The financial analysis compares a mix of historical and forecast financial ratios to compare the trends between the current regulatory period and the 2005-2010 regulatory period.

The key assumptions used in the analysis are as follows:

Capital structure: The model assumes that the distribution business has a capital structure of debt finance of 60% to shareholders funds of 40%. These ratios are calculated in relation to the total of regulated fixed assets and net working capital. Net working capital is assumed to be constant at $30 million over the 2005-2010 regulatory period. It is assumed that borrowings in excess of 60% are repaid as unscheduled repayments and that shareholders funds in excess of 40% are distributed as special dividends.

Borrowing capacity and interest: The cost of debt is assumed to be the nominal after tax cost of debt (7.4%) referred to in Table 10.10 of the Commission's determination.

Taxation: The model assumes that the distribution business is a taxpaying entity and ignores the possible effects of deferred taxation.

[192] For example, the Commission considered the Corporate Ratings Criteria, Published by the US Standards and Poors credit rating agency.

Analysis

Ability to service debt: These ratios measure the ability of the distribution business to meet its debt obligations.

	HISTORICAL					FORECAST				
(TIMES)	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10
EBITDA/Interest expense	3.24	2.89	2.83	2.75	2.83	2.83	2.87	2.88	2.88	2.90
Funds from operations interest cover*	3.17	3.03	2.92	3.00	2.78	2.90	2.94	2.95	2.93	2.94
Funds from operations to interest**	3.42	3.39	3.21	3.39	2.89	3.13	3.18	3.19	3.18	3.18

* This is defined as operating profit plus depreciation and amortisation less income tax paid, adjusted for disposals divided by interest expense.

** This is defined as funds from operations plus debt interest expense plus capital contributions divided by debt interest expense

The ratios show that the distribution business' ability to service debt is roughly maintained due to the draft price determination.

Ability to repay debt: These ratios measure the ability of the distribution business to repay its borrowings.

	HISTORICAL					FORECAST				
(PERCENTAGE)	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10
Funds from operations to avg total debt*	14.9	14.1	13.3	13.9	12.5	13.9	14.1	14.2	14.1	14.1
Retained cash flow after working capital to debt**	2.6	6.6	6.1	9.2	5.9	10.6	8.7	8.5	8.2	8.3

* This is defined as operating profit plus depreciation and amortisation less inc ome tax paid, adjusted for disposals, divided by average total debt during the year (expressed as %).

The ratios above show that the distribution business is in the same or better position to repay its debt after the draft price determination comes into effect, than it has been in the current regulatory period.

Ability to finance investment from internal sources: These ratios measure the ability of the distribution business to source funds from its operations to finance its capital expenditure.

	HISTORICAL					FORECAST				
(PERCENTAGE)	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10
Net cash flow to net capex*	292.9	238.3	193.4	162.2	232.1	147.3	149.0	156.7	160.0	150.5
Retained cash flow to capex**	51.3	112.3	89.9	108.5	110.1	78.3	93.0	95.0	94.5	89.9

* This is defined as operating profit plus depreciation and amortisation less income tax paid, adjusted for disposals divided by net capital expenditure (i.e. excluding customer contributions).

* This is defined as funds from operations less dividends paid divided by net capital expenditure (i.e. excluding customer contributions).

Although the ratios show that when compared to the current regulatory period, the distribution business' ability to source investment internally is reducing, it remains at a reasonably strong levels so as not to compromise the distribution business' financial position. The main reason for the reduction is the large increase in the distribution business' capital expenditure allowed under this draft determination.

All other things being equal, based on these ratios the Commission does not consider that the distribution business' financial position is compromised in the 2005-2010 regulatory period.

14.2 Customer Impact Analysis

Although this draft price determination focuses on ETSA Utilities, various issues discussed in the determination will also have an impact on customers' electricity bills. These are:

- Changes in the tariff structure;
- Changes in the cost allocation methodology;
- Changes in the overall revenue recovery for ETSA Utilities; and
- Annual changes in the prices (the impact of the 'X' factor).

The Commission has noted the various proposed changes to the tariff structure (see Chapter 12). ETSA Utilities is currently in the process of using the pricing principles to determine its tariffs for all customer categories. However, some tariffs for small customers have been included in this determination. Tariffs for large customers will be included in the Final Determination to be released in March 2005.

Table 14.1: Distribution Tariffs for Small Customers

(GST EXCLUSIVE)	TARIFF COMPONENTS	CURRENT TARIFFS	NEW TARIFFS*
Low Voltage Residential – Single Rate	Supply Charge ($ pa)	80.54	82.55
	Consumption ($/MWh)		
	First 4 MWh pa	58.51	45.83
	Thereafter	58.51	59.97
Low Voltage Off-peak Controlled Load	Supply Charge ($ pa)	17.85	0.00
	Consumption ($/MWh)		
	First 8 MWh pa	13.00	13.14
	Thereafter	13.00	23.17
Low Voltage Business – Single rate	Supply Charge ($ pa)	80.54	82.55
	Consumption ($/MWh)	57.85	55.97
Low Voltage Business – 2 rate	Supply Charge ($ pa)	199.00	94.05
	Consumption ($/MWh)		
	Peak – First 20 MWh pa	58.05	73.49
	Peak – Thereafter	58.05	59.96
	Off-peak	25.48	23.17

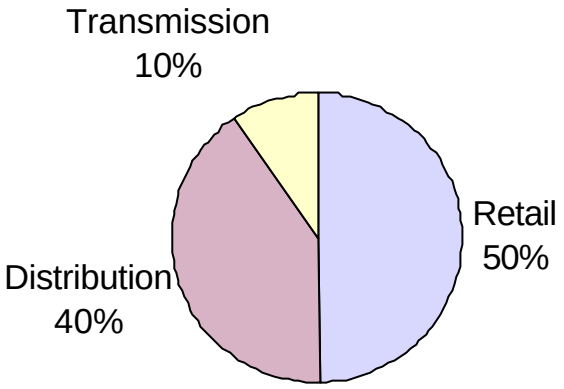
* Based on a CPI assumption of 2.5% for March 2005

Given that only small customer tariffs can be reasonably determined at this stage, the focus of the customer impact analysis is on small customers, particularly domestic customers since they make up the vast majority of small customers.

14.2.1 Impact on Domestic Customers

For an average domestic customer (consuming approximately 5MWh pa), distribution charges make up about 40% of the total annual bill.

Figure 14.1: Components making up the annual average residential bill



Given this proportion, only 40% of the percentage reduction in Distribution charges will be experienced by domestic customers.

As discussed in Chapter 12, a change to the tariff structure for domestic customers is proposed by ETSA Utilities. Consumption up to 4 MWh pa (first block of consumption) would be charged at a lower rate and any consumption over 4 MWh pa (second block) will be charged at a higher rate. The supply charge (fixed component of the distribution tariff) and the usage charge for consumption over 4 MWh pa (second block) will increase by one year's inflation. The reduction in distribution charges caused as a result of this determination will be fully incorporated into the first block.

Since the customer spread is skewed towards the lower consumption end, the change in the tariff structure provides most benefit to the majority of customers and thus achieves the greatest impact. This is illustrated in Figure 14.2, showing the percentage change in the annual distribution charges, overlapped with the residential customer spread.

Figure 14.2: Percentage change in annual Distribution bill for domestic customers (2005/06 relative to 2004/05)

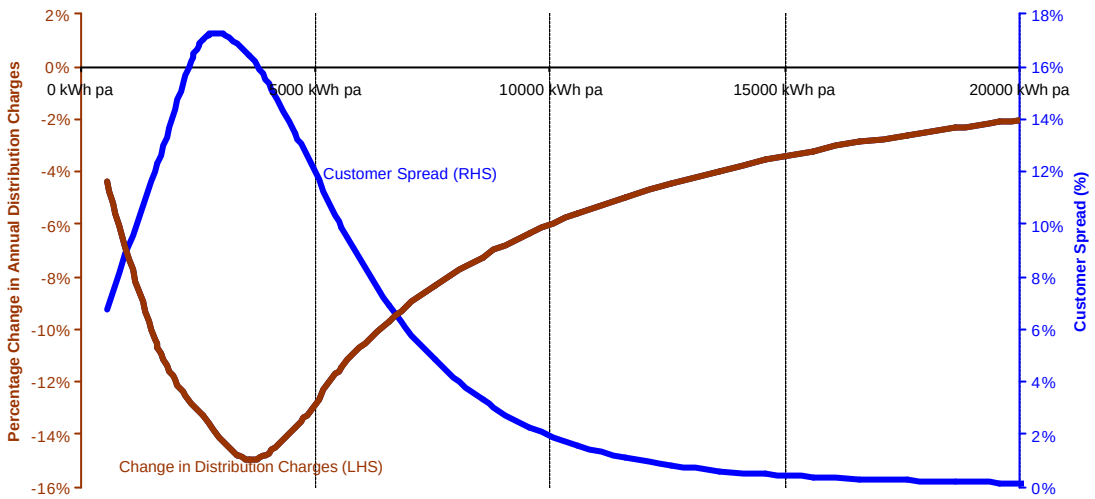
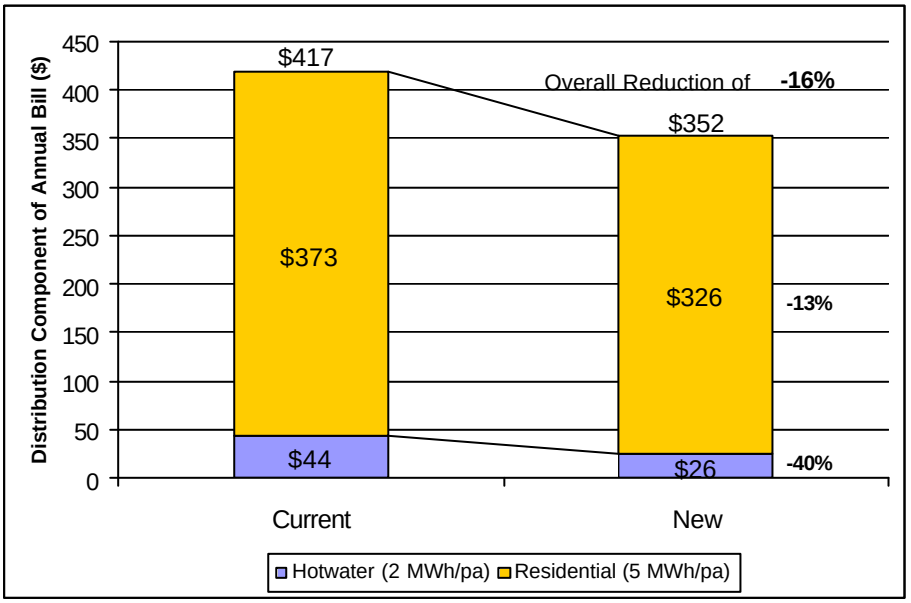


Figure 14.3 shows the average reduction in distribution charges for a residential customer consuming 5 MWh pa and 2 MWh pa of controlled load (Hot Water)[193].

Figure 14.3: Average reduction in Distribution charges for a typical residential customer (consuming 5 MWh pa and 2 MWh pa in controlled load)



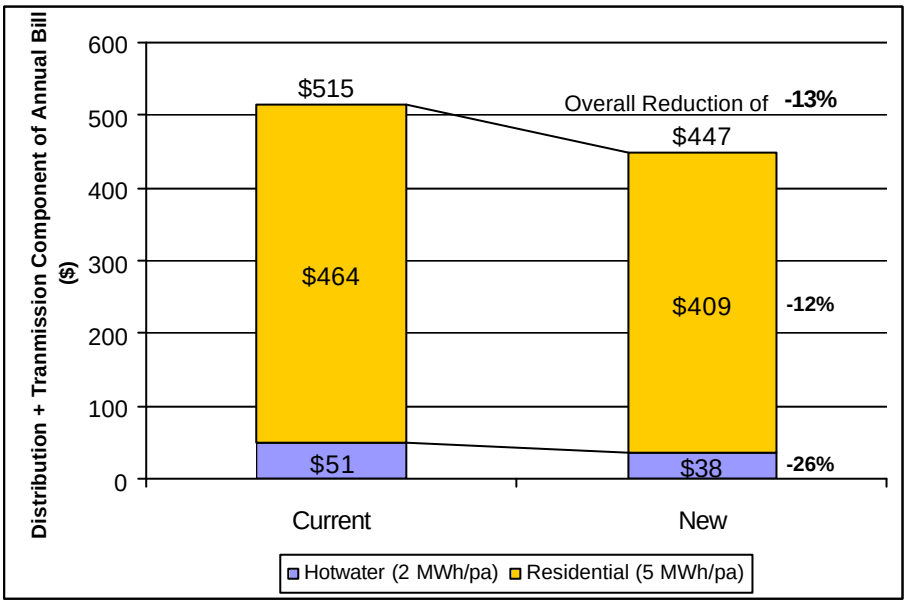
[193] The Commission is currently undertaking an Inquiry for retail standing contracts tariffs. This analysis does not consider any changes that may occur to the standing contract prices as a result of this Inquiry.

14.2.2 Inclusion of Changes in Transmission Charges

Although this determination relates only to distribution charges, in preparing the information for the review, ETSA Utilities has also changed the way the transmission charges are allocated to better reflect the true cost of purchase. This change provides an updated analysis of cost reflectivity of the transmission charges (an obligation under the NEC). The change in the allocation of transmission charges has also resulted in some reduction to residential customers.

Figure 14.4 shows the average reduction in both distribution and transmission charges for a residential customer consuming 5 MWh pa and 2 MWh pa of controlled load (Hot Water).

Figure 14.4: Average reduction in Transmission and Distribution charges for a residential customer (consuming 5 MWh pa and 2 MWh pa in controlled load)



14.2.3 Comparison with Victorian Distribution Charges for average residential customer

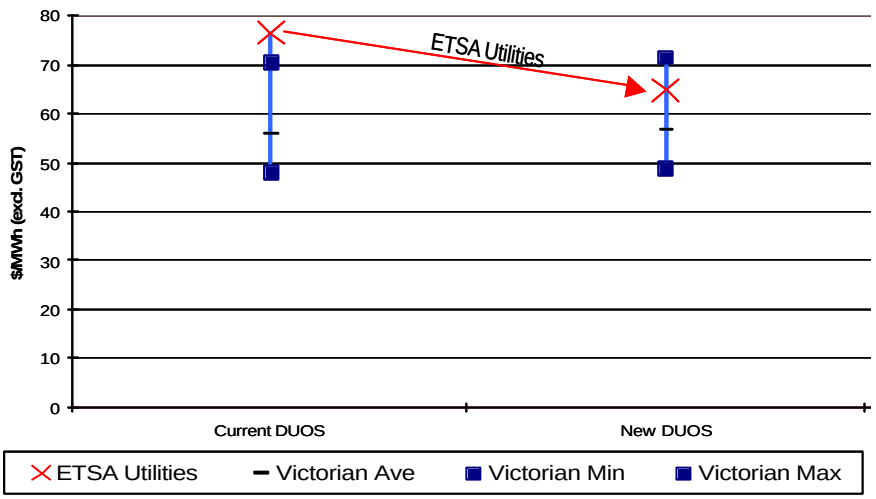
There are five Distribution Businesses (DBs) in Victoria. Each of the DBs have different tariffs applying to the various customer classes. ETSA Utilities is compared to the range of charges applied by the five DBs in Victoria.

During the 2000-2005 regulatory period, distribution tariffs for residential customers had consistently been at the higher end of the range for equivalent Victorian distribution charges[194].

[194] The Commission has included a similar comparative chart in all its Annual Performance Reports, including in the latest report: 2003-04 Performance Report, *Performance of Regulated Electricity Businesses*, pp 74.

Due to the reduction in the draft price determination, the distribution charges now fall within the equivalent Victorian distribution charges, as seen in Figure 14.5

Figure 14.5: Comparison of ETSA Utilities' charges with Victorian Distribution Charges (for a residential Customer consuming 5MWh pa)*



* This is based on tariffs applying from 1 Jan 05 for the Victorian DBs and tariffs applying from 1 July 05 for ETSA Utilities (based on an assumed 2.5% CPI)

Overall, the draft price determination has resulted in significant reductions for residential customers, re-structured to provide greater relief to the smaller end of the market.

15 NEXT STEPS

The Commission is releasing this draft price determination for an extended period of consultation.

The draft determination comprises:

Part A – Statement of Reasons

Part B – Price Determination

Comments are sought from stakeholders on both parts of the draft determination by **11 February 2005.**

The Commission will review all comments and prepare a final determination in March 2005. The new pricing arrangements will commence from 1 July 2005.

Over the period from December 2004 to June 2005, the Commission will undertake a consultation program on necessary changes to licences and codes to implement the proposals in this draft determination. Code changes will be implemented following the release of the final determination.