Decision

South Australian Transmission Network Revenue Cap 2003-2007/08

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Contents

Glossary

ACG	Allen Consulting Group
AR	Allowed Revenue
ASX	Australian Stock Exchange
Capex	Capital Expenditure
CAPM	Capital Asset Pricing Model
COAG	Council of Australian Governments
Code	National Electricity Code
Commission	The Australian Competition and Consumer Commission
CPI	Consumer Price Index
DB	Distribution Business
DNSP	Distribution Network Service Provider
DRP	Draft Statement of Principles for the regulation of Transmission Revenues
EAG	Energy Action Group
EBIT	Earnings before Interest and Tax
ECCSA	Electricity Consumers Coalition of South Australia
ElectraNet	ElectraNet SA
EPO	Electricity Pricing Order
ESC	Essential Services Commission
ESCoSA	Essential Services Commission of South Australia
ESIPC	Electricity Supply Industry Planning Council
ETSA	Electricity Trust of South Australia
EUAA	Energy Users Association of Australia
Gamma (γ)	Likely Utilisation of Imputation Credits
GST	Goods and Services Tax
GWh	Giga Watt hour
HMA	Hill Michael and Associates
IDC	Interest During Construction
Information requirements	Information Requirements Guidelines
IPART	Independent Pricing and Regulatory Tribunal
ITOMS	International Transmission Operations and Maintenance Study
km	Kilometre
kV	Kilovolt
MAR	Maximum Allowable Revenue
MAPS	Moomba to Adelaide Pipeline System
MEAV	Modern Equivalent Asset Valuation
Meritec	Meritec Pty Ltd
MFS	Maloney Field Services
MRP	Market Risk Premium
MTC	Murraylink Transmission Company
MVA	Mega Volt Ampere
MW	Mega Watt
MWh	Mega Watt hour
NECA	National Electricity Code Administrator
NECG	Network Economics Consulting Group
NEM	National Electricity Market

NEMMCO	National Electricity Market Management Company
NERA	National Economic Research Associates
NET	National Electricity Tribunal
NPAT	Net Profit after Tax
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Value
OFGEM	Great Britain's Office of Gas and Electricity Markets
Opex	Operating and Maintenance Expenditure
OTTER	Office of the Tasmanian Energy Regulator
PI Scheme	Performance Incentive Scheme
PSTN	Public Switched Telephone Network
PWC	PricewaterhouseCoopers
QCA	Queensland Competition Authority
RAB	Regulated Asset Base
RBA	Reserve Bank of Australia
Regulatory Principles	Statement of Principles for the regulation of Transmission Revenues
S&P	Standard and Poor's
SKM	Sinclair Knight Merz
SMHEA	Snowy Mountain Hydro-Electric Authority
SNI	**S**outh Australia - **N**ew South Wales **I**nterconnector
SOO	Statement of Opportunities
SA	South Australia
SPI	SPI PowerNet
TNSP	Transmission Network Service Providers
TUOS	Transmission Use of System
Urbis	Urbis Property Consultants
VAR	Voltage Amperes Reactive
WACC	Weighted Average Cost of Capital
WDV	Written Down (Depreciated) Value
WMC	Western Mining Corporation Copper Uranium

1 Executive Summary

1.1 Introduction

Under clause 6.2 of the National Electricity Code (code), the Australian Competition and Consumer Commission is responsible for determining the allowed revenue (AR) for ElectraNet SA.

ElectraNet is currently the predominant transmission network service provider (TNSP) in South Australia. It bought the business from the South Australian state government in October 2000 under a long-term lease. ElectraNet is a private limited company.

ElectraNet submitted its application for revenue cap on 16 April 2002. The Commission engaged Meritec Pty Ltd to review the application. The Commission published its draft decision on 11 September 2002. At each stage of the process the Commission placed the relevant documents on its website and invited submissions. It also convened a public forum on 4 October 2002.

This revenue cap decision covers the period 1 January 2003 to 30 June 2008.

This decision should be read in conjunction with the Commission’s draft decision and other relevant material on the Commission’s website such as ElectraNet’s application, Meritec’s reports and submissions from interested parties.

1.2 Cost of capital

The code requires the Commission to provide TNSPs with a fair and reasonable rate of return. The Commission uses the capital asset pricing model (CAPM) to estimate a fair return on assets. It uses a post-tax revenue model.

Table 1.1 Comparison of the weighted average cost of capital (WACC)

	Final decision (%)	Draft decision (%)	Application (%)
Nominal post-tax return on equity	**11.17**	11.40	13.66
Post-tax nominal WACC	**6.07**	6.39	8.66
Pre-tax real WACC	**7.17**	7.12	8.46
Nominal vanilla WACC	**8.30**	8.59	10.03

Table 1.2 WACC parameters

Parameter	Final decision	Draft decision	Application
Nominal risk-free interest rate (R_f)	5.17%	5.41%	5.90%
Expected inflation rate (F)	2.07%	2.30%	2.34%
Debt margin (over R_f)	1.22%	1.30%	1.72%
Cost of debt $R_d = R_f$ + debt margin	6.39%	6.71%	7.62%
Market risk premium (MRP)	6.00%	6.00%	6.50%
Gearing ratio	60%	60%	60%
Value of imputation credits (γ)	50%	50%	50%
Asset beta (β_a)	0.40	0.40	0.45
Debt beta (β_d)	0.00	0.00	0.00
Equity beta (β_e)	1.00	1.00	1.12

Note: The above parameters vary over time, according to market conditions. They have been calculated on the date of the decision.

1.3 Opening asset base

1.3.1 Introduction

The jurisdictional value of the opening regulatory asset base (RAB) was established at $685 million as at 1 July 1999. ElectraNet proposed three main changes to this value:

- revaluation of easements
- inclusion of interest during construction (IDC)
- re-admission of items optimised in 1998 but are now required.

1.3.2 Easements

Easements were incorporated at book value of $3.1 million as part of the jurisdictional valuation. However, the South Australian Department of Treasury and Finance wrote to the Commission on 10 August 2001 expressing reservations about the value. It suggested that the Commission could revalue the easements according to its *Draft Statement of the Principles for the Regulation of Transmission Revenues* (DRP)[1].

In its application ElectraNet proposed that the value of easements should be about $215 million. However, in its response to the draft decision, ElectraNet claimed that the value of easements should be at least $27.5 million. This value was based on SPI PowerNet's (SPI) easement valuation adjusted for differences in the number of easement ownerships and relative property prices between South Australia and Victoria.

[1] *ACCC, Draft Statement of Principles for the Regulation of Transmission Revenues, 27 May 1999.*

The Commission, as stated in its DRP and draft decision, prefers to value easements on the basis of actual costs indexed for timing differences. ElectraNet, however, has stated that it is unable to provide the Commission with historical cost information.

In its draft decision the Commission stated that, in the absence of any actual costs, it would adopt the figure of $3.1 million which, when adjusted for inflation, amounts to $3.5 million. The Commission maintains this view.

1.3.3 Interest during construction

ElectraNet claimed that the jurisdictional valuation did not make a fair and reasonable allowance for IDC of $44.6 million, as IDC was included only on those projects valued over $50 million.

Given its limited discretion the Commission believes it cannot question the policy adopted to determine the jurisdiction valuation. Therefore, as it did in the draft decision, the Commission has not included the IDC in the RAB.

1.3.4 Re-admission of previously optimised assets

ElectraNet claimed that the Sinclair Knight Merz (SKM) review in 1998 (conducted for ETSA Utilities) resulted in excluding redundant assets (optimisation) with a depreciated replacement value of $25 million. ElectraNet engaged SKM to review the entire asset base to update the optimisation effective as of 1 July 2001. SKM found that (net) assets with a depreciated value of $12.9 million are now required (due to load growth, etc) and should be re-admitted into the RAB.

In the draft decision the Commission preferred not to exercise its discretion to re-admit the optimised assets. However in the light of the submissions to the draft decision and considering the Commission's other recent revenue cap decisions, it has decided to exercise its discretion and restore the re-optimised assets of $12.9 million back into the RAB.

Table 1.3 Regulatory asset base 1 January 2003

	($m)
Jurisdictional valuation of system assets as at 1 July 1999	685
Capital expenditure [1]	138
Economic depreciaton [2]	(17)
RAB of system assets as at 1 January 2003	806
Optimised assets [3]	14
Easements [3]	4
RAB as at 1 January 2003	824

1. Net of disposals.
2. Straight line depreciation, less inflation.
3. Indexed to 1 January 2003.

1.4 Capital expenditure

1.4.1 Overview

ElectraNet has forecast a capital expenditure (capex) program of $374 million in real terms ($409 million nominal) over the regulatory period. Table 1.4 shows the adjustments that this decision makes to ElectraNet's proposed capex program.

Table 1.4 Capex allowance for the regulatory period

	(real) ($m)
ElectraNet's application	374
Add: Refurbishment [1]	62
Sub-total total capex	436
Less adjustments:	
Augmentations for distributed generation projects [2]	39
Monash to SA Border component of SNI [3]	14
Reduction in probability for Heywood augmentation [4]	17
Inconsistency with the probabilistic approach [5]	8
Subtotal adjustments	78
Capex allowance	**358**

1. In its application, ElectraNet included $77million of refurbishment expenses as operational expenditure over the regulatory period. The Commission directed Meritec to treat this refurbishment as capex. After reviewing the expenses, Meritec recommended that about $15 million be treated as opex. The Commission accepted the recommendation and treated the remaining $62 million as capex in the draft decision (section 1.4.2).
2. The benefits arising from these projects are uncertain and the code is unclear about who is to pay for them.
3. TransGrid will construct, own and operate this section of South Australia-NSW interconnector (SNI).
4. From 64 per cent to 12 per cent, as a result of reintroducing Robertstown to Monash component of SNI in ElectraNet's capex program.
5. Included in ElectraNet's application as contingency amounts.

1.4.2 Treatment of refurbishment

ElectraNet claims that a further $24 million (of the $62 million capitalised refurbishment works) should be treated as opex. The Commission has decided not to vary from its draft decision, noting that Meritec reviewed refurbishments and recommended that only $15 million be treated as operating and maintenance expenditure (opex).

In response to the draft decision ElectraNet and other TNSPs argued that the refurbishments should be treated as opex. They argue that the risk of optimisation, compliance with accounting standards and consistency require that these refurbishments be treated as opex.

The Commission considers that whether refurbishment is treated as capex or opex depends on the nature of the expense. At one extreme there could be genuine maintenance which is opex, whilst at the other extreme there could be refurbishment which is clearly of a capital nature.

The main driver for treating refurbishment as opex is the risk of optimisation. The Commission has addressed ElectraNet's concerns by quarantining capitalised refurbishment ($62 million) for 10 years (15 years in the draft decision) and depreciating the amount over the same period. The Commission also notes that this approach ensures smoother pricing over time and leaves a clear audit trail.

This treatment is subject to the condition that ElectraNet reports its actual refurbishment expenses against its asset management plan to the Commission on an annual basis (as part of its annual reporting requirements) and maintain records so that the refurbishment can be identified to the asset.

1.4.3 Commission's assessment of capex

The Commission notes that ElectraNet's proposed capex program represents a significant increase on historical levels for the transmission business. ElectraNet has proposed a capex allowance of approximately $80 million per annum over the regulatory period, while historically its capex program has averaged less than $40 million per annum.

In its capex report, Meritec expressed reservations about the ability of ElectraNet to actually carry out its proposed capex program, given potential limitations in the availability of resources to carry out the projects. Several interested parties shared Meritec's concerns about the ability of ElectraNet to deliver the capex program, noting that it represented nearly a 50 per cent increase in ElectraNet's asset base as at 31 December 2002.

Based on the work of Meritec and its own analysis, the Commission considers that a capex program of about $358 million over the regulatory period should be adequate for ElectraNet to meet its obligations under the code and the South Australian Transmission Code. It also considers that this amount would provide an incentive for ElectraNet to prioritise projects and pursue non-network options.

1.5 Operating and maintenance expenditure

1.5.1 ElectraNet's application

Table 1.5 Components of the average opex per annum proposed by ElectraNet

	($m)
Base level of opex	56
Refurbishment: the Commission transferred a total of about $62 million over the regulatory period (averaging about $11 million per annum) to capex in its decisions.	11
Grid support (the Commission prefers to show this category separately)	4
Total opex proposed by ElectraNet in its application	**71**

1.5.2 Historical opex

Just before the release of its draft decision, the Commission found that significant differences between opex amounts in ElectraNet's annual reports and the amounts reported to the South Australian Independent Industry Regulator (now known as the Essential Services Commission of South Australia (ESCoSA)) by ElectraNet under its performance incentive (PI) scheme.

The Commission has since found that these variations were mainly due to the PI scheme having a different scope of costs to those reported in the regulatory accounts. However, the Commission did find that ElectraNet's regulated accounts for 2000-01 contained several non-recurring expenses such as voluntary severance payments, acquisition costs and asset write-offs.

The Commission excluded the above items and grid support costs to arrive at a base opex figure for 2000-01 and 2001-02, which could be used to forecast future opex.

The Commission also examined the opex figures for the years before 2000-01, for which only limited details were available.

Table 1.6 provides the Commission's estimate of historical opex that could be used to forecast future opex.

Table 1.6 Estimate of SA transmission businesses' historical opex

Year	($m)
1997-98	29[1]
1998-99	32[1]
1999-00	32[1]
2000-01	34[2]
2001-02	35[2]
Meritec	43 [3]
ElectraNet	56 [4]

1. Annual report amounts excluding grid support and ancillary services costs ($12 million for 1997-98 and $7 million for 1998-99).
2. Regulatory account figures less grid support and one-off expenses.
3. Average over the regulatory period, Meritec's recommendation (excludes grid support).
4. Average over the regulatory period, ElectraNet proposed (excludes grid support and refurbishment that has been capitalised)

1.5.3 Commission's benchmarking of ElectraNet against other TNSPs

Given the differences among TNSPs, any single ratio is unlikely to reflect the true difference in performance. Each ratio would have its limitations. Therefore, the Commission looked at a suite of ratios such as opex per unit of line length ($/km), asset base (%), substation ($), electricity transported ($/GWh) and peak-load ($/MW).

Also, some ratios provide a more useful insight into relative performances. The Commission considers that opex/line-length and opex/asset base, while having some limitations, are more useful than the others.

The Commission considers that Powerlink is more comparable to ElectraNet than the other Australian TNSPs, although there are differences between the two.

Table 1.7 Benchmarking of opex: ElectraNet vs Powerlink (2003-04)

	Opex/route length ($/km)	Opex[1]/RAB[2]
ElectraNet Application	9,930	6 %
Final decision	7,600	5 %
Powerlink	5,630	2 %

1. Excludes refurbishment and grid support
2. Includes refurbishment

Since the draft decision, ElectraNet has made several submissions about the reasons for differences among TNSPs.

The Commission, as explained above, is aware that there are legitimate reasons for differences among TNSPs such as operational and scale differences. Therefore the fact that some of these ratios are higher than others does not, of itself, suggest that ElectraNet's efficiency is lower than those of other TNSPs.

1.5.4 Commission's assessment of opex

The Commission, like Meritec, has focused on assessing a reasonable level of total opex for ElectraNet rather than verifying individual cost components. If the Commission were to adopt cost-plus regulation, then details of costs would be important. As such, a more heavy handed and interventionist approach to verification would be necessary.

It assessing the opex allowance, the Commission is mindful of ElectraNet's claims that it has achieved substantial cost efficiencies as a result of pursuing best practices.

ElectraNet is now proposing to undertake a substantial capex program. Some of the capex will result in an increase in opex whereas others may result in a decrease. Overall the Commission considers that the capex program is likely to result in a small net increase in opex. This view is supported by Meritec's analysis.

In the draft decision the Commission considered that historical opex was about $39 million. However further examination of the figures reveal that comparable recent opex was about $35 million (table 1.6).

For the purpose of this final decision, the Commission, on balance, prefers not to further reduce the allowance of $43 million per annum that was provided in the draft decision. This amount is based on:

- Meritec's recommendation of $43 million
- an increase over and above the recent opex level (about $35 million per annum) to accommodate the net increase in opex as a result of the large capex program and to allow ElectraNet to spend on 'catch-up' maintenance expenditure
- the Commission's own benchmarking of opex ($43 million) against other TNSPs.

The Commission will monitor the maintenance expenditure and grid support payments through its annual reporting requirements.

An additional amount of $4 million per annum is allowed for grid support and $0.7 million per annum for equity raising costs. The allowance for grid support will be clawed back if it is not spent.

1.6 Service standards

In determining revenue caps, the code requires the Commission to take into account the service standards that TNSPs are expected to maintain. The Commission engaged SKM to develop a set of service standards for TNSPs. SKM’s final report is on the Commission’s website now. ElectraNet’s service standards were developed according to SKM’s recommendations in that report.

SKM has selected five indicators: three will be operational now and other two will be implemented later when data is collected. The average performance during the previous three years becomes the benchmark. If ElectraNet exceeds the benchmark it will earn an incentive payment and if it does not it will suffer a penalty. The maximum amount of penalty or incentive is one per cent of the revenue cap. The scheme is designed to have an expected value of zero.

1.7 Total allowable revenue

The actual revenue earned by ElectraNet for 2001-02 was approximately $139 million based on the electricity pricing order of South Australia (EPO). ElectraNet estimates that its earnings for 2002-03, based on the EPO method, would be about $144 million.

The Commission has determined a revenue allowance for ElectraNet that increases from $148 million in 2002-03 to $180 million in 2007-08, as shown in table 1.8. The decision is based on forecast inflation and applies a smoothing factor. The decision allows ElectraNet to substitute actual inflation figures (the eight weighted capital city consumer price index (CPI)), when they are known, for the forecast figures.

Table 1.8 ElectraNet’s smoothed AR 2002-03 to 2007-08 (nominal)

	2002-03 ($m)	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	2007-08 ($m)
Smoothed AR	**148.01**	**153.98**	**160.19**	**166.66**	**173.38**	**180.38**

The final maximum allowed revenue (MAR) will be determined by adding (or deducting) the service standards incentive (or penalty) amount to the above AR.

The Commission estimates that this decision is likely to result in a real price reduction of about four per cent from now to the end of the regulatory period, mainly due to the increase electricity transported (in MWh) exceeding the growth in (real) revenues.

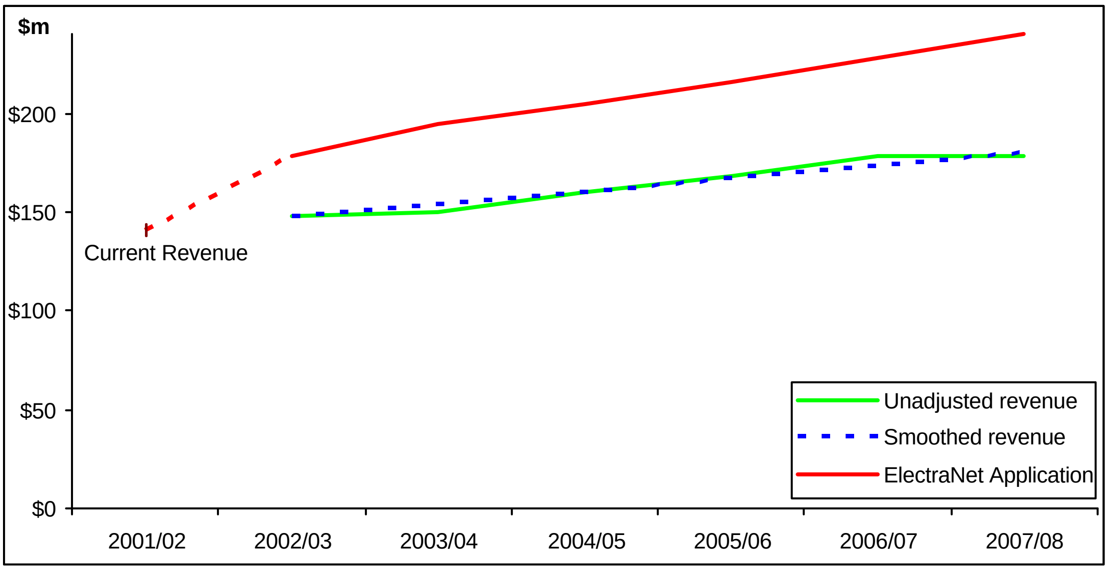
Table 1.9 summarises the key elements of the Commission’s final decision.

Table 1.9 Allowable revenue and its components

	Final decision ($m)	Draft decision ($m)	Application ($m)
Easements[1]	3	3	215
Optimisation[1]	14	0	14
Other system assets	806	802	840
RAB at 1 January 2003[2]	824	805	1069
Capex (real)	296	285	374
Refurbishment	62	62	77
Total capex[3]	358	347	451
Grid support per annum (pa)	4	4	4
Opex[4] pa	44	43	56
EPO under recovery	5	5	-
Nominal post tax return on equity	11.2%	11.4%	13.7%
AR[5]	**148**	**143**	**195**

1. Indexed to 1 January 2003.
2. Sum of easements, optimisation and other systems assets.
3. Sum of capex and refurbishment over the regulatory period.
4. Excludes capitalised refurbishment.
5. The final and draft decision figures are for 2002-03, (prorated for the first 6 months of 2002) and the application figure is for 2003-04 which is the first full financial year).

Figure 1.1 Revenue comparison for ElectraNet 2002-03 to 2007-08



Standard and Poor's (S&P) has indicated that the Commission's draft decision would not result in any rating action against ElectraNet. The Commission considers that ElectraNet is likely to maintain its BBB+ credit rating, given that AR in the final decision is higher than that in the draft decision.

2 Introduction

2.1 Background

The code establishes a regulatory framework which:

- provides that the Commission will determine the revenue caps to be applied to the non-contestable elements of participating transmission networks
- sets out how those regulated revenues, combined with the networks contestable revenues, will be translated into network charges.

The Commission is required to set a revenue cap for ElectraNet from 1 January 2003 for at least five years. This decision will cover five and a half years to align the regulatory period with ElectraNet's financial year (ending 30 June). This will simplify reporting and forecasting processes outlined in the Commission's *Statement of Principles for the Regulation of Transmission Revenues-Information Requirements Guidelines* (*Information Requirements*), and will minimise compliance costs.

This decision does not extend to the parallel network assets owned and operated by ETSA Utilities. These assets are regulated by the ESCoSA under chapter 9 of the code.

This document sets out the Commission's final decision in respect of ElectraNet's revenue cap. The remainder of this chapter sets out the structure of this document, the regulatory framework to be applied, the public consultation involved with the decision and an overview of ElectraNet's network.

2.2 Structure of this document

Chapter	Title / Description
3	Calculation of the weighted average cost of capital
4	Establishing the RAB at 1 January 2003
5	Capex allowance for the regulatory period
6	Opex allowance for the regulatory period
7	Calculation of total revenue using the information from the above chapters
8	Establishing service standard benchmarks and providing incentives and penalties
9	Financial indicator analysis

2.3 Objectives and principles of the regulatory regime

The code establishes that:

1. the transmission revenue regulatory regime must achieve outcomes which:
   - (a) are efficient and cost effective;
   - (b) are incentive based, including the sharing of efficiency gains between network users and owners as well as the provision of a reasonable rate of return (without monopoly rents) to network owners;
   - (c) foster efficient investment, operation, maintenance and use of network assets;
   - (d) recognise pre-existing government policies on asset values, revenue paths and prices;
   - (e) promote competition; and
   - (f) are reasonably accountable, transparent and consistent over time.
2. the regulation of aggregate revenue of transmission networks must:
   - (a) be consistent with the regulatory objectives (see 1 above);
   - (b) address monopoly pricing concerns, wherever possible, through the competitive supply of network services but otherwise through a revenue cap;
   - (c) promote efficiency gains and a reasonable balance between supply and demand side options;
   - (d) promote a reasonable rate of return to network owners on an efficient asset base where:
     - (i) the value of new assets is consistent with take-or-pay contracts or NEMMCO augmentation determinations;
     - (ii) the value of existing assets are determined by jurisdictional regulators and must not exceed than their deprival value; and
     - (iii) any asset revaluations undertaken by the Commission are consistent with COAG decisions.
3. the form of the economic regulation shall:
   - (a) be a revenue cap with a CPI-X incentive mechanism, or some other incentive based variant, for each network owner;
   - (b) have a regulatory control period of not less than five years;
   - (c) take into account expected demand growth, service standards, weighted average cost of capital, potential efficiency gains, a fair and reasonable risk adjusted return on efficient investment and ongoing commercial viability of the transmission industry; and
   - (d) only apply to those assets the Commission does not expect to be offered on a contestable basis.

Source: National Electricity Code, Version 1.0, 1998, clauses 6.2.2 - 6.2.5.

In May 1999 the Commission published its DRP, setting out how it proposes to regulate transmission revenues. The Commission is currently finalising the DRP.

ElectraNet's revenue cap was determined using an accrual building block approach. That is, various components (building-blocks) of the revenue cap are assessed individually using accrual accounting, and then combined (section 7.1 refers).

2.4 Process

The Commission:

- received the application from ElectraNet on 16 April 2002
- engaged Meritec to assess ElectraNet's proposed RAB, capex and opex
- invited interested parties to comment on the application, reports and submissions
- consulted with ElectraNet, other interested parties and government instrumentalities
- released its draft decision on 11 September 2002
- convened a public forum in Adelaide on 4 October 2002
- sought comments on the draft decision from interested parties
- further consulted with ElectraNet, other interested parties and government instrumentalities.

Copies of ElectraNet's application, Meritec's reports and submissions from interested parties are available on the Commissions website[2].

2.5 Overview of ElectraNet's transmission network

ElectraNet operates over 5576 circuit kilometres (km) of transmission lines and 68 substations, which include 6102 mega volts ampere (MVA) of installed transformer capacity throughout South Australia.

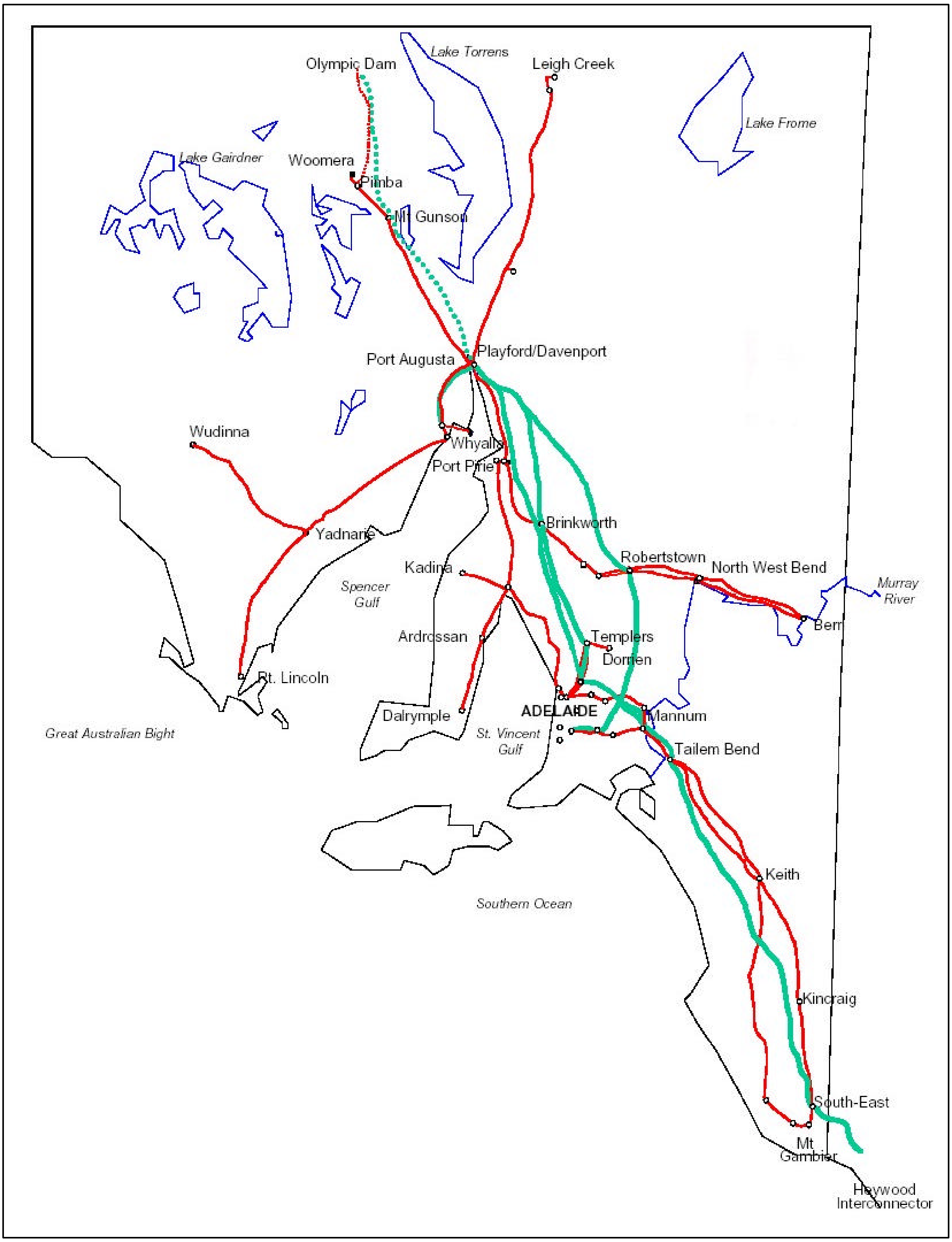
ElectraNet's network spans more than 1000 km from the Victorian border near Mount Gambier to Port Lincoln on the Eyre Peninsula, with radial extensions of over 200 km each to Leigh Creek, the York Peninsula and the Riverland. Figure 2.1 illustrates ElectraNet's network and highlights the major load centres in South Australia.

The South Australian network is characterised by long distances, a low energy density and a small customer base compared to other states. It also has a peaky demand profile mainly due to air conditioning load over summer, with the top 25% of demand being present for only 3% of the time.[3] ElectraNet's network supplied 2832 megawatts (MW) during the 2000-01 summer, approximately double the average demand.

[2] http://www.accc.gov.au

[3] NEMMCO, *2002 Statement of Opportunities*, Figure 3.4 (p3-18).

Figure 2.1 ElectraNet's transmission network



3 The cost of capital

3.1 Introduction

Clause 6.2.2(b)(2) of the code requires the Commission to seek to achieve a fair and reasonable rate of return on efficient investment as one of the objectives of economic regulation. Further guidance is provided in clause 6.2.4(c)(3) which states that the Commission must have regard to the WACC of the transmission network. The Commission therefore used the risk adjusted cash flow rate of return required by investors in commercial enterprises facing similar business risks to the transmission network as a basis for establishing the WACC for ElectraNet.

Electricity transmission is a highly capital intensive industry where generally return on capital accounts for about two-thirds of the AR. Relatively small changes to the cost of capital could have a substantial impact on the total revenue requirement and ultimately, on end-user prices. Hence, correctly assessing the return on capital is very important.

If the return on equity is too low, the regulated network will be unable to recover the efficient and fair costs of service. Perhaps more importantly, it may not provide sufficient return to the owner, thereby reducing its incentive to reinvest in the business. Conversely, if the return on equity is too high, networks will have a strong incentive to overcapitalise (‘gold plate’), thus creating inefficient investment and high cost to users.

3.2 The post-tax approach

In the DRP the Commission outlines its view on the appropriate expression of the return on equity that is to be achieved, and how it is to be used for deriving the regulated revenues. This view is summarised in the proposed statement 6.3:

> The Commission will apply the nominal post-tax return on equity as a benchmark. The revenues will be calculated on the basis of the cash-flows associated with the regulatory accounts necessary to deliver this return after taking into account liabilities and the assessed value of franking credits based on existing tax provisions and foreshadowed tax changes due to occur during the regulatory period.[4]

For this decision, the Commission has chosen to adopt the cash flow modelling approach as specified in the code and outlined in the DRP. This approach extracts the parameters relating to business income tax from the WACC formula. In doing so, the Commission explicitly models the impact of tax and franking credits on the required post-tax distributions in the cash flows. The remaining WACC formula, which has been termed the vanilla WACC, is merely the weighted average of the gross post-tax returns on debt and equity.

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[4] ACCC, *Draft Statement of Principles for the Regulation of Transmission Rev*enues, 27 May 1999, p. 84.

In its application, ElectraNet expressed concern regarding the Commission's preference for a post-tax nominal WACC framework. It suggested that a pre-tax method is more consistent with achieving the objectives of incentive regulation.

Conversely, AGL and the Energy Users Association of Australia (EUAA) urge the Commission to adopt a post-tax approach that is consistent with earlier decisions.

Commission's considerations

The Commission notes that pre-tax rates of return implicitly provide for an allowance in revenues to cover the expected tax liabilities over the life of the asset. As discussed in the context of the Commission's Victorian gas decision[5] and the DRP[6], applying a pre-tax rate of return in the regulatory framework creates several problems which are solved by moving to a post-tax rate of return.

The first problem is how to convert from the nominal post-tax return on equity benchmark provided by the CAPM to an equivalent real pre-tax WACC. There has been much discussion and divided opinion on the appropriateness of the sequences, which can have a substantial impact on the revenue decision. The post-tax cash flow modelling avoids this problem, as it does not attempt to convert the revenues into real terms. In addition, the cash flow modelling enables exogenous changes that may affect the accruing and recovery of income taxes.

The second problem with the pre-tax approach relates to uncertainties in making long-run forecasts of future tax liabilities, which vary with actual inflation outcomes and changes in the tax regime. By using the post-tax approach and modelling income taxes in the cash flows, the Commission can adjust for changes in the tax regime that alter the tax liabilities of a transmission network to ensure that it achieves the benchmarked return on equity over the life of the assets.

A third problem with the pre-tax approach has become known as the S-bend problem. In the pre-tax approach, the rate of return allows a fixed proportion of the return on capital to provide compensation in the revenue stream for current and future tax liabilities. However, because of tax concessions such as accelerated depreciation, generally little tax is payable early in the life of an asset and tax liabilities increase significantly later in its life after such concessions have been fully used.

Theoretically, this is less of a problem since the pre-tax return is intended to assume an effective tax rate over the life of the asset just enough to compensate the regulated entity/investor for the net taxes that it has to pay. The regulatory problem is a practical one as well as a political one. The uncertainty concerning the long-term tax forecasts already mentioned is one issue. Another relates to the adequacy of cash flows to enable the regulated entity to sustain investments sufficient to maintain its level of service later in the life of the assets, when tax liabilities greatly exceed the provision for them within the then current regulatory revenue.

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5 ACCC, decision-*Victorian Gas Final Decision*, October 1998

6 ACCC, Supplementary Papers-*Draft Statement of Principles for the Regulation of Transmission Rev*enues, 27 May 1999.

In principle the regulated entity has already been compensated for those tax liabilities in earlier cash flows so it is inappropriate to ask users to pay extra to meet the cash flow needs of the regulated entity. However, there is likely to be pressure for the regulator to concede to such a measure. Again, the post-tax approach provides a ready solution since taxes are assessed on an *as you go basis* and the regulated entity does not suffer tax liability uncertainty or potential shortfall.

Therefore, most of the regulatory difficulties linked to a real pre-tax based framework could be overcome by a method using post-tax returns and assessment of near-term tax liabilities using cash flow analysis.

3.3 The capital asset pricing model

Clause 6.2.2 of the code requires that one of the key outcomes that the revenue regulatory regime administered by the Commission, must provide for is:

> a sustainable commercial revenue stream, which includes a fair and reasonable rate of return to *Transmission Network Owners* and/or *Transmission Network Service Providers* on efficient investment, given efficient operating and maintenance practices.

Schedule 6.1(2.2.2) of the code states that various methods can be applied to estimate the return on equity (R_e) component-for example, prices to earnings ratios, dividend growth model and arbitrage pricing theory. However, the code states that the CAPM remains the most widely accepted tool applied in practice to estimate the cost of equity.

The CAPM calculates the required return given the opportunity cost of investing in the market, the market's own volatility and the systematic risk of holding equity in the particular company. The CAPM determines the rate of return from the perspective of the investor measured in cash flow terms. This includes the returns from year to year and any net appreciation in the capital.

The CAPM formula is:

$$R_e = R_f + \beta_e(R_m - R_f)$$

where: R_f = the risk free rate of return-usually based on government bond rates of an appropriate tenure

$(R_m\text{-}R_f)$ = the market risk premium (MRP)-the return of the market as a whole less the risk free rate

β_e = the relative systematic risk of the individual company's equity

The CAPM expresses the rate of return as the post-tax nominal return on equity. This can be adjusted to allow for debt to derive the corresponding return on assets, otherwise known as the WACC.

Key parameters

The key parameters relevant to WACC/CAPM analysis are:

- the risk-free interest rate (R_f)
- the expected rate of inflation (F)
- the cost of debt (R_d)
- the market risk premium (MRP)
- the likely utilisation of imputation credits (γ)
- the likely level of debt funding (D/V)
- the equity beta (β_e) of the company
- the effective tax rates on equity (T_e)

3.4 Estimate of the risk-free interest rate

The risk-free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. The yield on long-term Commonwealth Government bonds, which are viewed as risk-free as the government can honour all interest and debt repayments, is the closest to the risk free return.

3.4.1 Sampling period

In the CAPM framework all information for deriving the rate of return should, in principle, be as up-to-date as possible at the time the decision comes into effect. In the case of interest rates and inflation expectations, the financial markets set the parameters on a daily basis. Therefore it may be argued that there is little justification for using historical data.

On this issue Statement 6.7 of the DRP states:

> The risk free rate will be normally based on a 40 trading day moving average covering the eight weeks prior to the reset date unless there is evidence to suggest that the current rate of the day represents a transition to a new level which is expected to be maintained.

3.4.2 Submissions on the draft decision

Both SPI and ElectraNet argue that the Commission should be more flexible in its approach on this issue and advocate adopting a shorter sample trading period.

3.4.3 Commission's considerations

The Commission acknowledges that the financial theory underlying the CAPM explicitly specifies the use of *ex ante* returns. It also acknowledges the risk associated with using forecast information. The Commission recognises the inherent limitations of using both an 'on the day' rate and a 'historical average' approach in the workings of the CAPM.

By using an on the day rate in the CAPM, rates may reflect short-term fluctuations which differ to long-term trends. Such differences could arise from market volatility.

Exposure to short-term volatility can be minimised by averaging rates over a short term before the start of the regulatory period. The average rate can then be used in the CAPM. For regulatory purposes, regulators traditionally adopt an historical average when dealing with the risk-free rate.

The Commission notes that the Queensland Competition Authority (QCA), in its recent determination on regulation of electricity distribution networks[7], adopted a 20-day moving average. It concluded that while an on the day rate is theoretically correct, it may cause distortions to the total cost of borrowing. However, the QCA also noted that while long-term averages may smooth the interest rate cycle, the prevailing average would not represent current market expectations.

In its DRP the Commission states that a 40-day moving average would be the appropriate approximation of the risk-free rate to smooth out the short-term volatility of bond rates. The Commission has taken this approach in several regulatory decisions. Most recent examples include the *NSW and ACT*[8]*, Snowy Mountain Hydro-Electric Authority (SMHEA)*[9] *and Queensland*[10] revenue cap decisions, *Sydney Airports*[11], *Moomba to Adelaide Pipeline System*[12] (*MAPS*) decision and *NT Gas Pty Ltd*[13] access arrangement decisions.

The Commission remains of the view that it is appropriate to use a short-term average of the risk-free rate. Therefore, the Commission accepts ElectraNet's request for a shorter sampling period of 10 days. This also offers a degree of protection from transient volatility while ensuring that the selected rate closely reflects the most recent market activity. The Commission considers that there is no basis to believe that a service provider would be advantaged or disadvantaged by the length of the sampling period, so long as the service provider can appropriately hedge over the sample period. Accordingly, the Commission has used a 10-day moving average of bond rates in assessing ElectraNet's revenue cap.

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7 Queensland Competition Authority, *Final determination-Regulation of Electricity Distribution*, May 2001.

8 ACCC, decision-*NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04*, January 2000.

9 ACCC, decision-*Snowy Mountains Hydro-Electric Authority Transmission Network Revenue Cap 1999/00-2003/04*, February 2001.

10 ACCC, decision-*Queensland Transmission Network Revenue Cap 2002-2006/07*, November 2001.

11 ACCC, decision-*Sydney Airports Corporation Ltd. - Aeronautical Pricing Proposal*, May 2001.

12 ACCC, *Access Arrangement Proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System*, September 2001

13 ACCC, *Access Arrangement Proposed by NT Gas Pty Ltd. for Amadeus Basin to Darwin Pipeline*, May 2001.

3.4.4 Selection of the bond rate

The code suggests that the risk-free rate be determined by reference to the yield to maturity on long-term 10-year Commonwealth Government bonds, being the least risky debt instrument traded in the market.

However, a relevant factor influencing the selection of the risk-free rate is the frequency of regulatory determinations to which the WACC is applied. If the WACC is revised relatively often, then it would be more appropriate to use a shorter-term bond rate to derive the WACC for the regulated entity. Thus, an appropriate term for calculating the risk-free interest rate in the present context is the term between regulatory reviews, in the case of ElectraNet, five-and-a-half years. Therefore, the Commission will interpolate a five-and-a-half year bond rate based on the five-year and 10-year nominal bond rates.

While there is considerable support for the use of bond rates with terms corresponding to the life of the assets, the Commission has stated in previous decisions that they are not the appropriate approximation of the risk-free rate. The CAPM model used by the Commission is a single period model and given that investors review investments over short periods, a shorter-term bond rate is the appropriate measure.

3.4.5 Submissions by interested parties

The Commission received submissions relating to the selection of the bond rate from ElectraNet, Origin Energy (Origin), NRG Flinders (NRG), Western Mining Corporation Copper Uranium (WMC), SA Water, TransGrid, EUAA and Electricity Consumers Coalition of South Australia (ECCSA). Their comments focussed on:

- the risk-free rate should align with the life of the asset or regulatory period
- the Commission should ensure that this decision is consistent with its previous decisions.

Each is addressed below.

Alignment of the risk free rate with asset life or regulatory period

ElectraNet argues that the proposal to use a shorter-term risk-free instrument fails to recognise the underlying asset structure of the TNSP. ElectraNet further contends that by aligning the risk-free rate to that of the regulatory period, the Commission is not correctly interpreting CAPM.

ElectraNet and TransGrid believe that the risk-free rate should be aligned as far as possible with the actual life of the asset. ElectraNet adds that matching debt maturity with asset maturity suggests the use of a long trading bond of similar length that would best reflect efficient financing behaviour for a company such as ElectraNet.

However, ECCSA and EUAA argue that as the regulatory period is five years then a regulated rate of return should be assessed against a risk-free rate of a similar duration.

3.4.6 Submissions on the draft decision

SPI contends that the term of the risk-free rate should match the term of the underlying investment in the assets of the business. It argues that a 10 year basis for the risk-free rate would be consistent with both the long-term nature of infrastructure investment and the estimation basis for the MRP.

Consistency with other Commission decisions

ElectraNet argues that the Commission’s use of a five-and-a-half year bond rate is inconsistent with past regulatory decisions, specifically the NSW and ACT revenue cap decision. It further argues that the inconsistency of the Commission’s stance on the risk-free rate, in relation to its own and other regulatory decisions would send confusing signals and thereby increase regulatory risk.

ElectraNet also argues that the Commission’s use of a shorter-term bond rate is inconsistent with the approach taken by other regulators in Australia and overseas.

Conversely, Origin argues that ElectraNet’s claim for a risk-free rate of return based on a 10-year Commonwealth bond is inconsistent with the Commission’s DRP and previous revenue cap decisions. Origin also argues that any significant change in approach by the Commission from its previous revenue cap decisions would increase the level of regulatory risk.

ECCSA, WMC and NRG similarly support the application of a five-year bond rate as the proxy for a risk-free rate to be consistent with other recent Commission decisions.

3.4.7 Commission’s considerations

The Commission believes that using the nominal and real bond yields with terms that correspond to the regulatory period is appropriate for two main reasons.

First, the use of such bond yields will ensure that inflation rates to which the asset owners are exposed will correspond with the estimated rate.

Second, the use of yields commensurate with the regulatory period is appropriate under the CAPM framework. The CAPM is a one-period model and thus theoretically more appropriate to estimate the rate for one regulatory period, rather than over the course of many regulatory periods. Given that the regulatory framework seeks to return the relevant cost of capital, the regulatory asset value will be supported by expected cash flows at all times. Therefore the relevant period of the CAPM can be set to equal the immediate regulatory period without any loss of applicability.

The Commission accepts that this approach is not consistent either with the approach of other Australian regulators or with its own NSW and ACT revenue cap decision. However in the NSW and ACT decision, the Commission selected the 10-year rate to maintain consistency with the Independent Pricing and Regulatory Tribunal’s (IPART) regulatory decisions for the NSW distribution networks. The Commission also observed that the decision did not reflect its final position.

Nevertheless, using a bond yield with a term the same as the regulatory period is consistent with its approach as outlined in the DRP and with the Commission's other recent regulatory decisions, including:

- Queensland Transmission Network Revenue Cap 2002-2006/07, November 2001
- Access Arrangement Proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System, September 2001
- Sydney Airports Corporation Ltd-Aeronautical Pricing Proposal, May 2001
- Snowy Mountains Hydro-Electric Authority Transmission Network Revenue Cap 1999/00-2003/04, February 2001
- Moomba to Sydney Pipeline Draft Decision, December 2000
- Melbourne airport-Multi-User Domestic Terminal, August 2000
- Public Switched Telephone Network (PSTN), July 2000

In the past the Commission had relied on expert advice from Professor Kevin Davis about the appropriate risk-free rate to be used in regulatory decisions. The Commission is aware of alternative expert opinions put forward by interested parties and recently sought advice from Dr Martin Lally about the appropriate risk-free term rate the Commission should use.

Dr Lally advised that the Commission's approach in establishing the risk-free rate was indeed theoretically correct and appropriate in practice, given the nature of the financial framework being used. Dr Lally assessed the arguments against the five-year bond rate and decided that they are unfounded. He concluded that the five-year bond rate is the appropriate term to consider when the regulatory period is five years. Dr Lally's paper is available on the Commission's website.[14]

Given these arguments, the Commission believes that using nominal and real bond yields with terms to maturity corresponding to the regulatory period is the preferred approach. Only by using these yields will the rate exactly correspond with the expectations and the inflation risk premium faced by the service provider over the course of the regulatory period.

At the time of this decision, the nominal five-and-a-half year, 10-day moving average for Commonwealth bond rates provided a rate of 5.17 per cent.

3.5 Expected inflation rate

While the expected inflation rate is not an explicit parameter in the return on equity calculation, it is an inherent aspect of the risk-free rate and is also implicit in the cost of debt. Two sources of information are used in determining inflationary expectations:

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[14] M Lally, *Determining the risk free rate for regulated companies*, a paper for the ACCC, July 2002.

financial markets and government estimates. The financial markets' indicator of inflation is derived from the difference between the nominal and indexed bonds over a corresponding period. Alternatively, the Commonwealth Treasury periodically releases inflationary forecasts based on internal modelling.

Statement 6.10 of the DRP states:

> The Commission will estimate the cost of debt for a firm conforming to the financial structures implied by the regulatory accounts in consultation with relevant financial agencies.

However, maturity dates on the nominal and indexed bonds rarely correspond, requiring realignment using either interpolation or extrapolation. The process of interpolation and extrapolation performs a mathematical line of best fit, estimating an indexed bond rate at a given moment. This approach is consistent with the NSW and ACT, SMHEA and Queensland revenue cap decisions.

3.5.1 Commission's considerations

The Commission believes that using a bond rate corresponding to the regulatory review period is the appropriate measure of the risk-free rate because the asset owner's inflation risk is compensated exactly by an inflation risk premium implicit in the yield on the corresponding government bond. As the code specifies that the Commission must set a revenue cap for a period of not less than five years, revenues will be re-adjusted to take account of actual inflation. Therefore the risk of actual inflation diverging from anticipated inflation is limited to a five-year period in most cases and five-and-a-half years in the case of ElectraNet.

The yield on five-year bonds will include a premium for inflation risk of a five-year period, making it the appropriate term to approximate the risk-free rate in regulatory decisions. The Commission believes that using the 10-year or longer yield bond would over compensate the business for this inflation risk.

The Commission's method for deriving the inflation rate from the nominal and indexed bond rates is consistent with other Commission and jurisdictional regulatory decisions. For instance, in using this approach, the QCA argues that it delivers a forward-looking estimate of inflation rather than an historic measure. Furthermore, ElectraNet in its application supports the Commission's method in calculating expected inflation.

For this decision, by extrapolating the nominal and real bond rates, the Commission forecasts inflation of 2.07 per cent pa.

3.6 Cost of debt

The cost of debt is the debt margin over the risk-free rate on commercial loans. The cost of debt varies depending on the entity's gearing, its credit rating and the term of the debt. Applying the cost of debt to the asset base, using the assumed gearing, will generate the interest costs for regulatory purposes.

Statement 6.10 of the DRP states:

The Commission will estimate the cost of debt for a firm conforming to the financial structures implied by the regulatory accounts in consultation with relevant finance agencies.

3.6.1 Submissions by interested parties

ElectraNet proposes a cost of debt of 172 basis points above the nominal risk-free rate of return, from an appropriate range of 150 to 195 basis points. To support this claim, ElectraNet cites the decisions by the QCA and the Victorian Office of the Regulator-General (now the Essential Services Commission (ESC)), which adopted cost of debt margins of 165 and 150 basis points respectively.

ElectraNet and TransGrid further contend that debt margins are for the majority, measured as margins against the 10-year government bond rate. Therefore, if the risk-free rate is based on a five-year government bond yield, a compensatory adjustment must be made to the debt margin for the difference between the yields on the five versus 10-year government bond. This would put the debt margin premium on the upper end of the yield range.

However, SA Water argues that assuming a debt premium of 172 basis points is well above industry benchmarks.

ECCSA argues that debt available for the risky business with the express purpose of share acquisitions indicates that the cost of debt claimed by ElectraNet would seem to place its business activities in the same category as share acquisition. ECCSA contends that the premise of guaranteed revenue stream, which underpins a regulated business such as electricity transmission, should be provided with a much lower debt rate than that available for share acquisitions.

EUAA proposes that a cost of debt premium between 100 to 150 basis points. NRG notes that a significantly lower risk premium of 120 basis points was applied in the Queensland revenue cap decision.

3.6.2 Submissions on the draft decision

SPI and ElectraNet argue that recent capital market data supports a debt margin greater than 130 basis points.

ElectraNet also argues that the Commission has failed to address its claim for compensation for the interest rate risk it faces on new capital expenditure. It is arguing that the cost of debt should be increased by five basis points to allow it to manage such risk on future capital expenditure.

3.6.3 Commission’s considerations

The risk of an entity’s debt is a function of the amount of asset backing, or the degree of leverage or gearing. The greater the debt to asset value or debt to equity ratio, the greater the risk and, therefore, the debt margin (other things being equal).

In considering an appropriate debt margin for an entity, the Commission adopts industry-wide benchmarking, thus offering an incentive for minimising inefficient debt financing. This is consistent with the DRP.

The calculation of the benchmark debt margin is essentially an empirical matter. It requires the Commission to consider the appropriate benchmark credit rating of the TNSP and the debt margin associated with that rating in the market.

Regarding the credit rating of a service provider, the Commission considers it is appropriate to estimate a benchmark rather than use an actual credit rating, given that the credit-worthiness of the entity is partly under managerial control and the use of a benchmark is consistent with other assumptions. The Commission believes that relevant Australian electricity transmission and distribution companies should be used as the basis for a benchmark.

Table 3.1 below sets out the long-term credit rating for 10 Australian electricity companies that have been assigned a credit rating from ratings agency S&P.

Table 3.1 Credit ratings associated with electricity companies

Company	Long-term rating
Ergon Energy	AA+
Country Energy	AA
EnergyAustralia	AA
Integral Energy	AA
SPI PowerNet	A+
Citypower Trust	A-
ETSA Utilities	A-
Powercor Australia	A-
United Energy	A-
Electranet	BBB+

Source: Standard and Poor's (www.standardandpoors.com.au), October 2002.

On the basis of this data, the average credit rating of these entities approximates to a credit rating of A.

In its sample of determining the average credit rating for the electricity industry, the Commission has included both private and government entities. The Commission considers that by simply using stand-alone and private entities, it would provide too small a sample to obtain an average credit rating for the electricity industry. The Commission also notes that there could be a wide range of factors relating to why the average credit rating for gas companies, at BBB+, may be lower than electricity companies.[15]

15 Standard and Poor's, *Energy Australia & New Zealand*, November 2001, p. 14.

In assessing the creditworthiness of Australian gas companies, Standard and Poor's would consider a number of key issues. They relate to specifically to regulatory risk; counterparty risk; and overall volume of demand for gas.

Accordingly, the Commission considers that an A credit rating represents an appropriate proxy credit rating for the benchmark electricity company.

Having established a proxy credit rating, a benchmark debt margin can be determined. Debt is raised by asset owners either through bank markets or through the private and public capital markets. Debt requirements have primarily been met by bank markets for projects involving construction in Australia.[16]

The Commission understands that the interest margin associated with bank issued debt is generally lower than capital market interest margins. However, information on the debt margin associated with bank issued debt is generally not widely available. The Commission therefore considers that it is reasonable to use capital market data as the benchmark, which is biased in favour of the TNSP.

The current 10-day moving average benchmark spread over the government bond yields, for corporate bonds with a maturity of five years, is 111 basis points.[17] The Commission considers it is appropriate to add a benchmark 10.5 basis points for prudent debt raising costs to the debt margin faced by a TNSP.

Therefore, for this decision, the Commission will use a debt margin of 121.5 basis points. Combined with the nominal risk-free rate of 5.17 per cent, it suggests a nominal cost of debt figure of 6.39 per cent for use in the WACC estimate.

3.7 Debt and equity raising costs

ElectraNet did not make a request for debt raising or equity raising costs in its application. As such, the Commission did not consider that it was a relevant issue for ElectraNet and hence no allowance was made in the draft decision.

3.7.1 Submissions on the draft decision

However, in response to the draft decision, ElectraNet and SPI refer to the issue of debt and equity raising costs. Both argue that the debt margin should be increased by eight basis points to take into account debt raising costs, consistent with the Commission's draft decision on GasNet.

ElectraNet and SPI also note that the draft decision on GasNet allowed for equity raising costs equivalent to 48 basis points on the value of equity and request that the Commission allow these benchmark equity raising costs in their final decisions.

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16 Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines*, report for the ACCC, May 2002. p.7.

17 CBASpectrum website: www.cbaspectrum.com

3.7.2 Commission's consideration

Debt raising costs

To raise debt, a benchmark service provider has to pay debt financing costs over and above the debt margin. One cost that is incurred is the additional payment made to a bank or financial institution for the arrangement of debt.[18] The Commission considers that an allowance should be provided for a reasonable benchmark of debt financing arrangements and bank fees. The Commission acknowledges that these fees are likely to vary between each debt issue and also over time with market conditions. However, it also recognises that a benchmark needs to be established to determine a reasonable allowance for revenue calculation.

According to financial institutions, a spread of five basis points each year represents an appropriate estimate of fees payable to a bank for the arrangement and distribution of debt. This benchmark is based on debt with a maturity of five years. The net present value of this fee is calculated and levied when the debt is arranged.

Another cost often incurred is a dealer swap margin which is payable to the relevant financial institution.[19] The Commission considers that this is a valid cost given that debt providers traditionally provide their funding through a floating interest rate facility, but often require companies to enter into hedging arrangements to reduce the extent of interest rate risk.[20] The Commission understands that a benchmark swap margin is currently set at about three basis points per year on issued debt. This fee may be levied either as an upfront fee or as an annual margin.

ElectraNet provided the Commission with a range of quotes and the fees payable in its submission to the draft decision. While this data has improved the Commission's understanding of establishment costs, it is considered inappropriate to use as the allowed costs should be based on a benchmark electricity transmission company, rather than the actual costs facing ElectraNet.

The Commission has researched debt raising transaction costs. This research has been based on the premise that, as with the calculation of the debt margin, the assessment of debt raising transaction costs is an empirical matter that should take into account current market costs. However, the Commission notes that this is a new area of analysis and will further consider these issues in future decisions.

The Commission contacted several industry analysts to assess the validity of debt raising costs and to acquire market estimates for these expenses. In particular, Westpac Institutional Bank gave the Commission detailed information about the transaction costs associated with capital market raisings. According to Westpac, the cost categories such as arrangement, placement fees, dealer swap margin, credit rating, agency and legal costs represent valid expenses incurred when raising debt. Westpac noted that

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18 Macquarie Bank, May 2002, p. 21.

19 ibid, p. 21.

20 ibid, pp. 16, 21.

while transaction costs are likely to vary between issues, on average between 10.5 to 12.5 basis points represents current market establishment fees facing a benchmark service provider raising debt on capital markets.

Accordingly, the Commission considers 10.5 basis points may be more appropriate for a benchmark A-rated electricity business, given that such an entity is likely to pay at the lower end of the dealer swap margin range.

As well as the above mentioned costs, a service provider may choose to engage in ‘credit wrapping’ when raising debt. This allows a service provider to raise debt based on a AAA credit rating for a fee payable to a credit monoline.[21] Under such an arrangement, a service provider may improve on the benchmark cost of debt and keep the benefits achieved. The Commission does not consider that an allowance for credit wrapping should be given to service providers. Regulated businesses are given a benchmark payment to compensate for the cost of debt, and if a company believes it can outperform this benchmark, then the costs (and benefits) associated with pursuing this strategy are its responsibility.

Therefore, the Commission considers that it is appropriate to provide a benchmark allowance for bank fees and dealer swap margin of a total of 10.5 basis points per year. The Commission proposes adding 10.5 basis points to the debt margin and thereby allowing the recovery of this cost through the WACC.

Equity raising costs

As with debt raising costs, the Commission considers it is appropriate to provide a benchmark allowance for equity raising costs. Equity raising costs must be paid by an entity when it raises capital. These costs are paid to equity arrangers for services such as structuring the issue, preparing and distributing information and undertaking presentations to prospective investors.[22]

The Commission has researched equity raising costs and has collected recent Australian data about it. In particular, the information about equity raising costs for several major Australian infrastructure equity raisings has been sourced and appears in the table 3.2.

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[21] ibid, p. 12.

[22] ibid, p.10.

Table 3.2 Equity raising costs

	Date of offer	Details of offer	Raising costs ($m)	Total offer ($m)	Fees as % of total offer	Fees per year (%)[4]
United Energy	March 1998	IPO-stapled securities	20 [1]	968.2	2.1	0.126
Macquarie Communications Infrastructure Group	July 2002	IPO-stapled securities	13	310	4.2	0.256
Australian Pipeline Trust	May 2000	IPO-units	12	488	2.5	0.150
Envestra	July 1999	Rights offer, convertible notes and placement issue	10.1 [2]	310	3.258	0.199
GasNet	October 2001	IPO-units	15 [3]	260.16	5.77	0.352
Average			**14.02**	**467.27**	**3.548**	**0.217**

Source: Company prospectuses; Commission calculations.
1. Includes underwriter fees, selling fees, advisory fees, legal fees, accounting fees, printing, advertising and other expenses.
2. Underwriting fees, advisory fees, legal fees, accounting fees, printing, advertising, stand duty and other expenses.
3. Includes the Joint Lead Manager's commissions and fees, accounting fees, legal fees, lodgement fees, listing fees, fees for other advisers, prospectus design, printing and other miscellaneous expenses (including taxes and other government charges).
4. Amortised in perpetuity using a real vanilla WACC of 6.11 per cent.

Recent equity raising costs for Australian infrastructure equity issues, as noted above, fall between 2.10 and 5.77 per cent of total equity raised. Amortised in perpetuity, this amounts to costs of between 0.126 to 0.351 per cent.

The Commission considers that an average of these annual costs represents an appropriate Australian benchmark for the purposes of this decision. Accordingly, the equity raising costs of 0.207 per cent per year of regulated equity should be used. With a RAB of $823.75 million and the assumed benchmark gearing ratio of 60:40, this amounts to an average allowance of $0.748 million over the regulatory period. This equity raising cost is in the opex allowance for the Commission's modelling purposes.

As with debt raising costs, the Commission intends to undertake further research on this issue for future regulatory decisions.

3.8 Market risk premium

The MRP is the premium above the risk free rate of return that investors expect to earn on a well-diversified portfolio. That is, the return of the market as a whole less the risk-free rate:

$$MRP = R_m - R_f$$

Statement 6.8 of the DRP states:

> The Commission will adopt what it perceives to be the accepted value of the market risk premium available at the time of the regulatory decision.

Under a classical tax system, conventional thinking suggests a value for the MRP of around 6.0 per cent.

While the concept of the WACC and its application for determining regulated revenues is unambiguously forward-looking, estimates of the future cost of equity are not readily available. Practical applications of the CAPM therefore rely on the analysis of historic returns to equity to estimate the MRP.

3.8.1 Submissions by interested parties

ElectraNet argues that historical data and benchmarking estimates of the Australian MRP indicate a figure towards the upper end of the range of 6.0-8.0 per cent is justified. It further argues that there is no evidence to support a declining MRP. ElectraNet believes that an estimate of 6.5 per cent is conservative.

Conversely, Origin contends that recent trends in financial markets and inflation suggest the MRP should be lower. Both Origin and EUAA cite international comparison and cite the UK regulator setting a MRP of 3.5.

Origin and EUAA do not see any reason why international financial markets would differentiate Australia and the UK, given Australia's markets have been fully open since the 1980s and international capital is highly mobile. EUAA also argues that the research cited by ElectraNet does not cover the period since 1998, in which there are indicators showing a downward trend in the MRP.

ECCSA argues that ElectraNet is a monopoly that operates in a very low risk environment with a guaranteed revenue stream. Therefore it is absurd to assume that ElectraNet should have a MRP which is above the lower end of the MRP range.

TransGrid argues that as with the cost of debt margin, the MRP has conventionally been estimated as a premium over a risk-free rate of return defined as the 10-year government bond rate. Therefore to maintain internal consistency between CAPM parameters, if a risk-free rate based on a five-year government bond is adopted, an adjustment must be made to the MRP compensating for the difference between the yields.

3.8.2 Commission's considerations

The Commission has noted the research indicating that the MRP has fallen over recent years. However, the Commission is wary that this may only reflect short-term market trends. Based on the more traditional views, the Commission's assessment of the MRP suggests that it lies between 5.0 per cent and 7.0 per cent. For this decision, the Commission chooses the mid-point of this range, which is a MRP of 6.0 per cent.

The Commission also maintains that the current MRP of 6.0 per cent is on the high side and therefore sufficient to compensate for the difference between the five and 10-year bond yields.

The Commission notes a Jardine Fleming Capital Partners survey of professional market participants' MRP expectations, which found that on average these participants thought the historic MRP for Australia was 5.87 per cent. The survey also found the expectation for the future MRP is approximately 1.0 per cent below this figure.

However, the Commission acknowledges that these expectations reflect substantial uncertainty. If the Commission is satisfied that the MRP is trending downwards in the longer term, it will adopt a lower MRP.

3.9 Value of franking credits

As outlined in the code, under an imputation tax system a proportion of the tax paid at the company level is, in effect, personal tax withheld at the company level. Australia has a full imputation tax system. However, the proportion of company tax paid that can be claimed as a tax credit against personal tax varies depending on factors such as the marginal tax rate of the recipient of the franked dividend.

The analysis of imputation credits and their impact on assessed costs of capital in Australia is a developing field and some issues remain contentious. In any event, the rate of use of tax credits γ (gamma), has a major effect on the WACC.

However, there is little doubt that franking credits do have some value. As stated in Schedule 6.1(5.2) of the code:

> as the ultimate owners of government business enterprises, tax payers would value their equity on exactly the same basis as they would value an investment in any other corporate tax paying entity. On this basis, it would be reasonable to assume the average franking credit value (of 50 per cent) in the calculation of the network owner's pre tax WACC.

There is considerable debate about the precise value of franking credits. As with other parameters of the WACC and CAPM equations, selecting a value for this particular input is ultimately a matter of judgment having regard to the available empirical evidence.

3.9.1 Submissions by interested parties

ElectraNet proposes a γ to the value of 50 per cent. While ElectraNet contends that for companies with substantial foreign ownership the value of γ is closer to zero, in principle, it agrees with the Commission that current ownership should not be the basis for setting γ.

ElectraNet also argues that, with respect to the recent taxation changes, increasing the value of γ towards one is without evidence due to:

- the uncertainty surrounding the full impact of the tax changes particularly regarding the concessional treatment of capital gains relative to income
- the limited demonstrated impact of these arrangements on the marginal investor
- other tax changes reducing the value of franking credits to investors.

3.9.2 Commission's considerations

The Commission recognises that an increase in the value of the business represents a return on equity. The business will therefore capture the full value of franking credits regardless of actual distribution. It would not be appropriate to model the retained franking credits within the regulated entity as it is an equity item that would be over-ridden by the Commission's regulatory assumptions on gearing. Therefore, the Commission believes it is more appropriate to assume that the benefits of franking credits are fully distributed because the shareholders will receive the value of franking credits either attached to dividends or via an increase in the value of their investment.

The Commission also notes that it is not enough to support a conclusion that, for even a partly owned foreign company, foreign capital is required to finance a firm's projects. Even assuming that a significant proportion of foreign ownership is required, the Commission maintains this does not prove the γ should be set at zero, as it does not rule out overseas investors obtaining foreign tax advantages not available to local investors. The likelihood that such foreign tax benefits exist suggests that γ should lie above zero.

Moreover, Australia's taxation legislation was modified on 30 June 2000 to accommodate the Ralph review recommendations on franking credits. The alteration to the tax law ensures that resident individuals receive the full benefit of franked dividends regardless of their tax position. The change results in franking credits being treated as a refundable rebate, similar to the private heath insurance rebate, to resident individuals rather than merely a deductable rebate as it previously applied.

Therefore, the Commission believes that a more appropriate value for γ is closer to one. However, it recognises that further research is required and no consensus has yet developed among Australian academics and practitioners for adjusting the rate of use of tax credits. It is therefore inappropriate for the Commission to lead in this area and further work is required before altering its current position on γ. Accordingly, in line with recent Commission decisions, a γ of 0.5 is used in this decision.

3.10 Gearing

A benchmark gearing ratio needs to be established for ElectraNet to identify the appropriate weighted average cost of debt and equity in the WACC.

Schedule 6.1(5.5.1) of the code states that:

> gearing should not affect a government trading enterprise's target rate of return … For practical ranges of capital structure (say less than 80 per cent debt), the required rate of return on total assets for a government trading enterprise should not be affected by changing debt to equity ratios.

3.10.1 Submissions by interested parties

ElectraNet states that its actual gearing is over 60 per cent. It does not believe that a 60 per cent gearing ratio would necessarily reflect efficient financing. However, it has adopted the Commission's benchmark of 60 per cent in its application as this is the appropriate benchmark for the industry.

ECCSA has received advice that ElectraNet's actual gearing is about 80 per cent. It argues that given the prevailing high levels of gearing for regulated infrastructures, there is a strong case for the Commission to review the gearing levels assumed in past decisions. ECCSA believes that a gearing of 60 per cent is too conservative, while a 70 per cent gearing would appear to replicate the actual financing for regulated enterprises.

3.10.2 Commission's considerations

Capital structure can have a major bearing on not only the debt margin but also the required return on equity (although within reasonable bounds it is unlikely to affect the asset cost of capital or the WACC). The greater the level of gearing implies the greater the risk of both debt and equity. However, over reasonable ranges, the risk of the total assets does not change. This is because the change in the weighting of capital from equity to debt maintains a constant risk level for the assets as a whole, even though the beta measures of both debt and equity will increase.

Table 3.3 shows that the typical capital structure assumed by regulators has been 60 per cent debt as a proportion of total assets. In theory, the asset cost of capital should be stable within the range of 40-70 per cent. The Commission considers that in the circumstances, a leverage of between 50-60 per cent would be reasonable. Given that most regulators have adopted a gearing of 60 per cent, there is little compelling reason to vary from this benchmark.

Table 3.3 Gearing levels adopted in regulatory decisions

Entity	Industry	Debt/Debt+Equity
QCA(2001)	Electricity distribution	60%
ESC (2000)	Electricity distribution	60%
ACCC (2000)	Electricity transmission	60%
IPART (1999)	Electricity distribution	60%
OTTER (1999)	Electricity distribution	50-70%
OFGEM (1999)	Electricity distribution (UK)	50%
IPART (1999)	Gas distribution	60%
ACCC/ESC (1998)	Gas transmission	60%
ESC (1998)	Gas distribution	60%

In the DRP, the Commission noted that it would not be using the actual gearing of a TNSP, instead it would use an appropriate benchmark. A survey conducted by S&P[23] suggests that the upper and lower band of the gearing ratio for a transmission and distribution business should be 65 per cent and 55 per cent.

While noting the ECCSA's concerns, the Commission still believes that a 60 per cent gearing is appropriate.

Therefore, the Commission will adopt a gearing ratio of 60 per cent, consistent with recent regulatory decisions, ElectraNet's application and the mid-point of S&P's appropriate range.

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23 'Standard and Poor's Rating Methodology for Global Power Companies', 1999.

3.11 Betas and risk

The equity beta is a measure of the expected volatility of a particular stock relative to the market as a whole. It measures the systematic risk of the stock-that is, the risk that cannot be eliminated in a balanced and diversified portfolio. Generally, the Australian Stock Exchange (ASX) is used as a proxy for the whole market. An equity beta of less than one indicates the stock has a low systematic risk relative to the market (the market average being equal to one). Conversely an equity beta of more than one indicates the stock has a high risk relative to the market.

The debt beta captures the systematic default risk of a debt investment. In this regard, it is the debt analogue of equity beta. Just as the equity beta represents a measure of the systematic risk of a company relative to the market as a whole, debt beta represents the extent to which the likelihood of the company defaulting on its debt obligations is correlated with movements in market returns.

Table 3.4 Average equity beta by industry listed on the ASX

Industry	Average Equity Beta
Property trusts	0.366
Alcohol and tobacco	0.420
Food and household	0.424
Transport	0.463
Diversified industrials	0.719
Engineering	0.756
Building materials	0.857
Paper and packaging	0.953
Developers and contractors	0.954
Banks and finance	0.967
Infrastructure and utilities	0.983
Tourism and leisure	1.084
Chemicals	1.128
Investment and financial services	1.131
Retail	1.269
Mining and energy	1.305
Insurance	1.394
Other metals	1.502
Miscellaneous industrials	1.568
Diversified resources	1.571
Gold	1.678
HealthCare and bio-technology	1.899
Media	2.076
Telecommunications	2.772

Source: Australian Graduate School of Management centre for research in finance; risk measurement service

For publicly listed companies, equity betas can be calculated using their dividend stream plus the change in the value of the stock. When an equity beta is calculated for a particular company, it only applies for the particular capital structure of the firm. A change in the gearing will change the level of financial risk borne by the equity holders and therefore the equity beta. A common approach to enable betas to be compared across companies with different capital structures is to derive the beta that would apply if the firm was financed with 100 per cent equity. This is known as the asset or ‘unlevered beta’ and can then be used to calculate the equivalent equity beta for a particular level of gearing (known as ‘re-levering’ the asset beta). While there are a number of levering formulae, the Commission has consistently applied the formula developed by Monkhouse:[24]

$$\boldsymbol{b}e = \boldsymbol{b}a + (\boldsymbol{b}a - \boldsymbol{b}d)\left[1 - \left(\frac{rd}{1+rd}\right)(1-g)Te\right]\frac{D}{E}$$

However, when a firm is not listed, equity betas cannot be calculated directly from economic returns. In such cases, conventional practice has been to benchmark the firm’s equity beta relative to other companies or sectoral averages. In the context of regulated electricity networks even this approach is problematic, as there are limited Australian reference stocks for such businesses. Nonetheless, the Commission has traditionally used the infrastructure and utilities group average. Table 3.4 highlights the average equity beta by industry listed on the ASX as at March 2002.

The Commission also notes that it is difficult to find any conclusive evidence for a specific asset beta for electricity transmission networks. Table 3.5 outlines the approach taken in recent regulatory decisions in relation to asset betas for electricity and gas businesses.

Table 3.5 Recent regulatory decisions on asset betas for electricity and gas

Decision	Industry	Asset Beta
ESC, price determination	Electricity distribution	0.40
ACCC, Snowy Mountains	Electricity transmission	0.40
ACCC, NSW and ACT	Electricity transmission	0.35-0.50
ACCC, Queensland	Electricity transmission	0.40
IPART, electricity DBs	Electricity distribution	0.35-0.50
QCA, price determination	Electricity distribution	0.45

3.11.1 Submissions by interested parties

ElectraNet in its application proposes an asset beta of 0.45, which equates to an equity beta of 1.12. ElectraNet believes that the Commission should use an equity beta towards the higher end of a feasible range arguing that it faces higher risk resulting from several factors as discussed below.

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24 ACCC, *DRP*, pp. 79-81.

Betas and bypass risk

ElectraNet contends that it should be allowed a higher equity beta due to the greater bypass risk facing electricity transmission companies compared to that of distribution networks, in particular from gas pipelines and new gas-fired power stations. ElectraNet argues that overall systematic risk is likely to be high.

In response to ElectraNet's claim for an equity beta of 1.12, Origin states that allowing a high beta would imply that ElectraNet is exposed to greater than average market risk. Origin argues that this is not an accurate representation given that ElectraNet operates in a regulated environment with stable cash flows. Origin submits that ElectraNet's claim for an asset beta of 0.45 is partly based on comparison with AGL. This is inappropriate given that AGL also runs a retail business, which faces additional risk.

Similarly EUAA is surprised at ElectraNet's claim for an equity beta of 1.12. EUAA argues that ElectraNet's claim for an equity beta of 1.12 is not credible given its status as a regulated electricity business and in a state where load growth is not expected to be high. EUAA argues that it is difficult to justify a high equity beta for electricity transmission, as they are relatively low risk businesses and subject to a regulated income set within a well-defined regulatory framework.

EUAA also notes that the revenue cap framework used by the Commission allows the transmission companies maximum revenues, which protects them from the possibility of any reductions arising from general economic downturn. Consequently, EUAA regards an appropriate equity beta for ElectraNet to be in the range of 0.6 to 0.8.

In its submission, ECCSA notes that the asset beta for ElectraNet should reflect that it operates in an industry with a guaranteed revenue stream in an extraordinary and very inelastic market. Historically, electricity transmission enterprises have shown a remarkably stable cash flow from their operations. This would imply a lower asset beta.

Size effect and CAPM

ElectraNet submits that much evidence, particularly through research in financial literature, suggests the investment rate of returns for small companies are greater than would be expected based on the measured beta of the CAPM. Therefore the equity beta would be an insufficient explanatory factor of asset returns. ElectraNet argues that it is a small electricity transmission company in terms of asset size and is smaller than the other transmission companies in the NEM. For this reason, ElectraNet states that it would be appropriate to incorporate an increment to beta, which would reflect the adjustment required to the CAPM for the size effect of ElectraNet.

ECCSA states that, counter to ElectraNet's claim of being a small firm, ElectraNet is not a small firm because its assets, revenue and profit comparable to large companies listed on the ASX. While noting that ElectraNet is smaller than other transmission companies in the NEM, ECCSA contends that this in itself does not rank ElectraNet as a small firm.

Asymmetric risk

In addition to undiversifiable risk, which is priced by the CAPM, ElectraNet also argues that there is evidence of asymmetric risks that are not captured by the CAPM. In ElectraNet's view, this risk should be treated as an addition to the cost of equity capital. ElectraNet states the following asymmetric risks that are unique to transmission companies:

- assets becoming stranded as customers change consumption patterns and competitors change strategies
- regulatory bodies adjusting policies or regulatory frameworks
- changes in asset valuation methodologies.

ElectraNet argues that these asymmetric risks are different to the risks compensated for in the CAPM, as they are unavoidable (insurance against such risks is not available) and cannot be diversified away by the firm investors. It claims a value of 0.5 per cent as an addition to cost of equity (as determined in CAPM) will be enough to cover these asymmetric risks.

3.11.2 Commission's considerations

Betas

The Commission notes that an equity beta estimate of 1.0 was adopted for the draft decision. This suggests that the TNSP experiences the same volatility as the market in general. However, this is not consistent with the frequently held views that gas and electricity transmission businesses are less risky and have more stable earnings than the market average. Greater stability suggests that the equity beta should be less than 1.0.

A report prepared by Allen Consulting Group (ACG) for the Commission suggested an equity beta for Australian gas transmission companies of just below 0.7.[25] ACG also considered that the data for comparable businesses in the USA, Canada and UK. This data produced lower beta estimates and ACG concluded that this secondary information supports the view that Australian estimates are not understated. ACG stated:

> Exclusive reliance on the latest Australian market evidence would imply adopting a proxy equity beta (re-levered for the regulatory-standard gearing level) of 0.7 (rounded-up). Moreover, regard to evidence from North America or UK firms as a secondary source of information does not provide any rationale for believing that such a proxy beta would understate the beta risk of the regulated activities. Rather, the latest evidence from these markets would be more supportive of a view that the Australian estimates overstate the true betas for these activities.[26]

[25] ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, p. 46.

[26] ibid, p. 42.

ACG recommended that a conservative approach to beta estimation be retained by Australian regulators with an equity beta estimate of 1.0. ACG noted:

> In the future, however, it should be possible for greater reliance to be placed upon market evidence when deriving a proxy beta for regulated Australian gas transmission activities.[27]

For the reasons indicated by ACG, the Commission considers that it may be premature to rely on market data exclusively when determining the equity beta. Accordingly, the Commission considers that an equity beta of 1.0, while biased in favour of the service provider, is appropriate for ElectraNet.

The Commission also notes that a debt beta estimate of zero has been applied in its previous electricity regulatory decisions. The debt beta can be determined from the formula:

$$ß_d = (r_d - r_f) / MRP$$

The Commission, in the past, considered that a regulated entity with a guaranteed revenue stream would have a low systematic default risk and therefore treated the debt beta as a residual parameter. Also, providing debt margins to network service providers had been assumed to implicitly incorporate debt raising costs. However, now that debt raising costs are being considered explicitly on top of the debt margin, it implies a higher debt margin. In this case, the debt beta formula above would suggest a higher positive debt beta.

With the current proposed values for the relevant parameters (the debt margin at 1.335 and MRP at 6.0), the calculation results in a debt beta of approximately 0.22. However, following further work into the debt beta, ESC has concluded that it is likely to be between zero and 0.18 although a value towards the upper end of this range was more likely.[28] ACG also considered this information and suggested that an appropriate range for the debt beta would be between zero and 0.15.[29]

The Commission considers that an appropriate value for the debt beta for this decision is zero. The Commission notes that this is also biased in favour of the service provider and it may be more appropriate to incorporate a positive debt beta in its future electricity regulatory decisions.

Bypass or asset stranding risk

The Commission notes ElectraNet's claim that it would face bypass risks, particularly from gas pipelines and new gas-fired power stations, which could leave its assets stranded. However, the Commission believes that the risk of asset write-downs occurring is a normal aspect of the business environment faced by competitive firms. For instance, in the marketplace, there is a risk that a firm's assets may become

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27 Ibid, p. 43.

28 ESC, *Draft Decision: review of gas access arrangements* , July 2002, pp. 231-233.

29 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, final report for the ACCC, July 2002, pp. 28-29.

obsolete (stranded) by the actions taken by a competitor at any time. In the case of a regulated firm, the regulator, when making a decision to optimise, acts as a proxy for effects of a more competitive solution that would be available in the relevant market.

The Commission considers the industry-derived betas used to determine the regulatory asset beta would normally include an element representing stranding risk. Nevertheless, this is not to say that a regulated entity will not face additional stranding risk so that the firm bears an asymmetric risk justifying a form of compensation.

However in the DRP, the Commission states that it will permit regulated firms to adjust its depreciation allowances in response to identifiable asset stranding risks when those risks are properly assessed as being material. For such arrangements to work efficiently it will be important for the TNSP to advise the regulator well in advance of by-pass risk actually occurring.

Size effect and CAPM

The Commission acknowledges that recent discussions in finance theory explore the possibility that the predictions of CAPM are not consistent with observed returns. As a result, research is continuing on variables currently omitted from CAPM, but which may have explanatory power over expected returns.[30] Evidence appears to show that small firms tend to realise higher rates of return than those predicted by CAPM. However, the Commission notes that these results, published in various studies and based on empirical evidence, have triggered considerable debate and, as such, have been criticised by the market for three reasons:

- data mining (i.e. a ‘mere coincidence’) which is almost inevitable if enough explanatory variables are to be tested

- the possibility that results are simply a remnant of the market proxy that is selected. For instance, if the market proxy was changed, other variables may be able to offer a better explanation.

- sensitivity of results to various changes in data and method, including new data sets and the deletion of extreme observations. This is similar to the survivorship bias argument which revolves around the inclusion of only the surviving companies in tests of CAPM. In such cases, only subsets of firms existing over a particular study period are actually included in the analysis. The resulting bias can be overcome if the sample used for analysis includes all companies, both failed and surviving.

Finally, the major problem with research into the tendency for small firms to realise higher returns is a lack of underpinning theory.

The Commission also agrees with ECCSA’s assessment that while ElectraNet is small relative to other transmission networks in the NEM, it is not small compared to all companies listed in the Australian market. For example, ElectraNet ranks about 860 out

[30] In this respect, Eugene Fama and Kenneth French have been most successful and argue that the additional factors size and book to market equity ratio, help explain expected returns.

of the top 5000 companies in Australia in terms of revenue.[31] Also, in terms of assets it would hardly qualify as small. Therefore, the Commission does not consider a compensation for size effect should be incorporated into ElectraNet's asset base.

Asymmetric risk

ElectraNet submits that it has no alternative but to bear asymmetric risks, and should therefore be permitted a return that explicitly includes the actuarially fair premium for insuring against this risk. Furthermore, since insurance coverage is not available, the TNSP is forced to self-insure.

The Commission deals with the issue of self-insurance in chapter 5.

Any theoretical model of asset pricing relies on the assumptions underpinning the model. The CAPM relies, *inter alia*, on the two assumptions that returns are normally distributed and that investors possess 'quadratic utility functions'. The evidence in the financial literature is that returns exhibit non-normal returns and quadratic utility functions do not seem plausible.

Other complex asset pricing models, including state preference models, Merton model, Breeden model, Cox Ingersoll Ross model and Fully Revealing Rational Expectations models, may well provide conceptual rigour which the CAPM lacks. However, the Commission considers CAPM's simplicity in explaining asset returns through its correlation with the market portfolio, coupled with its ease of application, provides a 'fair and reasonable' rate of return for a regulated entity.

Therefore, the Commission does not believe that it should provide additional compensation to ElectraNet through the CAPM framework. If it is demonstrated that extraordinary contingencies have arisen, then the Commission will consider these case by case and will address them by way of a pass-through.

ElectraNet will be required to obtain the Commission's approval before incorporating any pass-through charge, in relation to the size of the adjustment and demonstrate the materiality and reasonableness of such an adjustment.

Conclusion

As highlighted in table 3.4, ElectraNet's proposed equity beta of 1.12 is closer to the equity beta expected in the chemicals and investment/financial services sectors. The Commission traditionally uses the infrastructure and utilities group average, which currently lies just below 1.0. The Commission does not propose to compensate ElectraNet for other risks (e.g. small company size, asymmetric) identified in its application. Therefore, for the purposes of this final decision, the Commission will adopt an asset beta of 0.4 and a debt beta of zero, which equates to an equity beta of approximately 1.0.

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31 *The Business Who's Who of Australia*, Dun and Bradstreet Marketing Pty Ltd.

3.12 Treatment of taxation

The effective tax rate is defined as the difference between pre-tax and post-tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that lessen tax liabilities or defer them. Although the tax rate on accounting income is always at the corporate rate, in any year the income assessable for tax purposes can be quite different from the net revenues available to the business.

The timing aspect and the fact that taxes are assessed on the basis of nominal income means that the prevailing inflation rate also has a significant impact on the effective tax rate. The effect that deferral of tax has on the timing of cash flows does not generally cause administrative difficulties for a corporate entity that are well accustomed with uneven cash flows.

In recent decisions, the Commission applied the existing statutory company tax rate of 30 per cent. This was in the context of difficulties in determining a satisfactorily accurate long-term tax rate as part of the pre-tax real framework being used at the time. The capital-intensive nature of electricity utilities has historically meant that the effective tax rate for such networks has been less than the statutory tax rate.[32]

As noted previously, the Commission considers that moving to the post-tax nominal framework which uses that effective tax rate can potentially generate more appropriate and cost reflective revenue caps. Furthermore, the Commission's WACC calculations require deriving a value for the effective tax rate.[33]

3.12.1 Commission's considerations

Based on the Commission's approach to modelling the effective tax rate, the Commission has derived an effective tax rate of 39.05 per cent.

3.13 Conclusion

The Commission has carefully considered the values that should be assigned to ElectraNet's cost of equity given the nature of its business and current financial circumstances. Accordingly, the parameter values used are the most appropriate, as justified in the above arguments, and are tabled below.

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[32] According to IPART calculations, the average effective tax rate paid by the NSW distributors amounted to 25 per cent in 1996/97 (see IPART, The Rate of Return of Electricity Distribution Networks, Discussion Paper, November 1998, p. 9).

[33] The Monkhouse formula is $\beta_e = \beta_a + (\beta_a - \beta_d)\ \{1 - [r_d/(1+r_d)](1-\gamma)T_e\}\ D/E$

Table 3.6 Comparison of cost of capital parameters proposed by ElectraNet and the Commission

Parameter	Final decision	Draft decision	ElectraNet's proposal
Nominal risk-free interest rate (R_f)	5.17%	5.41%	5.90%
Expected inflation rate (F)	2.07%	2.30%	2.34%
Debt margin (over R_f)	1.22%	1.30%	1.72%
Cost of debt $R_d = R_f$ + debt margin	6.39%	6.71%	7.62%
Market risk premium (R_m-R_f)	6.00%	6.00%	6.50%
Debt funding (D/V)	60%	60%	60%
Value of imputation credits γ	50%	50%	50%
Asset beta β_a	0.40	0.40	0.45
Debt beta β_d	0.00	0.00	0.00
Equity beta βe	1.00	1.00	1.12
Nominal post-tax return on equity	11.17%	11.40%	13.66%
Post-tax nominal WACC	6.07%	6.39%	8.66%
Pre-tax real WACC	7.17%	7.12%	8.46%
Nominal vanilla WACC	8.30%	8.59%	10.03%

4 Opening asset base

4.1 Introduction

ElectraNet's revenue cap commences on 1 January 2003. As such the Commission must determine the value of ElectraNet's non-contestable transmission assets as at this date. This chapter explains the Commission's assessment of this value.

Clause 6.2.3(d)(4) of the code limits the Commission's ability to exercise discretion in valuing the opening RAB. Put simply:

- if the jurisdictional authorities had determined the value of opening RAB, then the Commission is required to use that value
- if not, the Commission is required to value the opening assets consistent with the asset base established by the jurisdictional authorities
- the value provided to the Commission must not exceed the deprival value of those assets, where deprival value is generally defined as being the lesser of an asset's optimised depreciated replacement cost (ODRC) or economic cost.

The Commission understands that a jurisdictional value of RAB was not determined in South Australia. The authorities, however, established an asset base valued at $685 million as of 1 July 1999.

The Commission engaged Meritec to help it assess the opening RAB.

4.2 ElectraNet's proposal

ElectraNet proposed three main changes to the opening jurisdictional valuation:

- in response to the draft decision, ElectraNet submitted that the value of easements should be at least $27.5 million—in the application it asked for $215 million, which was subsequently reduced to $198 million
- inclusion of interest during construction (IDC) of $44.6 million
- re-admission of items optimised in 1998 amounting to $12.9 million.

Each of these proposed changes are discussed in the following sections.

4.3 Easements

4.3.1 Jurisdictional valuation

The South Australian Department of Treasury and Finance wrote to the Commission in August 2001 noting that:

- easements were incorporated at book value of $3.1 million as it had insufficient time to value them according to the DRP issued by the Commission in May 1999
- independent valuations of the easements suggested a substantially higher value than $3.1 million
- it believed that the code clause 6.2.3(d)(4)(iii) allowed the Commission to revalue easements consistent with the RAB established by the participating jurisdiction.

4.3.2 ElectraNet's application

In its application ElectraNet used a hybrid model to value easements:

- deprival value of compensation costs, valued at about $111 million by Maloney Field Services (MFS) in 1997 indexed by inflation to $136 million
- replacement value of acquisition costs, valued by Sinclair Knight Merz (SKM) in 2002-$87 million (reduced from $104 million in the original application) - ElectraNet did not use the MFS valuation of acquisition costs which amounted to about $20 million.

4.3.3 Meritec's review

Meritec employed Urbis Property Consultants (Urbis) to advise on easement value.

Meritec accepted the MFS valuation of easement compensation costs of $136 million. However it did not agree with the easement acquisition costs assessed by SKM. Meritec considered that most of the acquisition costs were already captured in the valuation of other assets. Meritec assessed that acquisition costs were about $36 million. Hence the total value of easements recommended by Meritec was about $172 million as at 1 January 2003.

4.3.4 Submissions from interested parties

The majority of interested parties (EAG, ECCSA, EUAA, NRG, SA Water and TXU) considered that the Commission should do no more than roll forward the existing jurisdictional asset valuation. They argued that as these costs are sunk costs, there was little basis for any revaluation. Further, SA Water were concerned that the replacement cost used in the jurisdictional asset base might be much higher than necessary and that rolling forward the regulatory asset base would lock in such anomalies over the regulatory period.

However, other TNSPs supported ElectraNet's position that the Commission had no grounds to value easement rights, other than at deprival or replacement value in accordance with the code. However, in light of the DRP and previous revenue decisions, TransGrid recognised that the Commission prefers historical cost to value easements. TransGrid also argued that the Commission must recognise the genuine transactions costs that were incurred in any new easement acquisition.

4.3.5 Submissions on the draft decision

The ECCSA, EAG and EUAA supported the Commission's treatment of easements and IDC and the decision not to adjust the jurisdictional valuation. ECCSA argued that the South Australian Government sold these easements at $3.1 million, and that this was the value accepted by ElectraNet at that time of sale. ECCSA also believed that ElectraNet should have addressed any discrepancy as part of the sale process instead of asking the Commission to make a backward looking adjustment.

On 5 September 2002 the South Australian Minister for Energy wrote to the Commission concerning easement valuation, recommending that:

> the ACCC adopt an approach that discounts the easement values in Victoria for the difference in real estate values, and values the easements in South Australia accordingly.

4.3.6 Submission by ElectraNet in response to the draft decision

In line with the minister's recommendation, ElectraNet proposed a revised value for the historic easement compensation cost of at least $27.5 million at 1 July 2001.

This valuation was derived from the historic costs recognised by the Commission in its Victorian transmission network draft decision[34]. ElectraNet adjusted this value for differences in various factors such as line length, the number of easement ownerships and property values between Victoria and South Australia. On this basis, ElectraNet proposed that a fair and reasonable valuation for the historical easement compensation costs in South Australia was within the range $22.6-32.3 million, with $27.5 million representing the mid-point.

4.3.7 Commission's considerations

As stated in section 4.1 the Commission has limited discretion in valuing the jurisdictional RAB. If a judgment made by the jurisdiction in establishing the RAB still applies then the Commission cannot substitute its own judgment.

In this context, although a jurisdictional valuation of easements was $3.1 million, the South Australian authorities explicitly stated their reservations about the value (see section 4.3.1). Hence the Commission may have the discretion to value according to the DRP as suggested by the South Australian authorities.

The code stipulates that assets should not be valued above their deprival value. It therefore imposes an upper limit on asset values. However the Commission considers that it would be inappropriate to value easements at this maximum limit, i.e. deprival value. This view is based on theoretical considerations such as the appropriateness of the method given the special characteristics of easements and practical considerations such as the reasonableness of returns to TNSPs.

The Commission also notes that the deprival method results in a very high value for easements compared to other valuations in its previous decisions relating to the NSW

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[34] *Victorian Transmission Network Revenue Caps 2003-2008 - Draft Decision*, 24 September 2002.

and the ACT[35] and Queensland[36] revenue caps. It considers that valuing easements on the basis of deprival value would mean unreasonably high returns to TNSPs, resulting in unacceptably high cost to transmission customers.

Moreover, the Commission notes that the South Australian authorities had the MFS valuation ($132 million in 1997) when they established the jurisdictional RAB. Still the authorities preferred to qualify the book value of $3.1 million by stating that it was lower than other independent valuations, rather than replacing it with the MFS valuation.

As stated in the DRP the Commission prefers to value easements on actual costs suitably indexed for timing differences. ElectraNet, however, has stated that it is unable to provide actual (historical) costs. Instead it worked out a proxy value based on SPI's easement values.

In the draft decision, the Commission stated that its role is not to supplement ElectraNet's application. It maintains this view. Therefore the Commission has used the same figure of $3.1 million (indexed to 1 January 2003 is $3.4 million) in this decision.

4.4 Interest during construction

4.4.1 ElectraNet's application

ElectraNet claims that the jurisdictional asset base did not make a fair and reasonable allowance for IDC as it was only included on projects valued at over $50 million.

ElectraNet engaged PricewaterhouseCoopers (PWC) to analyse the construction projects that were carried out at that time and determine an appropriate allowance for IDC. PWC concluded that 7.5 per cent or $44.6 million should be added to the construction costs of system assets.

ElectraNet therefore argues that the value of system assets as at 1 July 1998 in the jurisdictional asset base should be increased by $44.6 million.

4.4.2 Meritec review

Meritec considered that an amount of $40.9 million was reasonable as an allowance for IDC. However, it recognised that the Commission is constrained from allowing additional IDC as a judgment was made by the jurisdiction in establishing the RAB. Consequently Meritec excluded IDC from the opening RAB.

4.4.3 Commission's consideration

In the draft decision the Commission argued that the jurisdictional authorities had adopted a policy of not including IDC on projects valued at less than $50 million.

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[35] *NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04-Decision*, 25 January 2000.

[36] *Queensland Transmission Network Revenue Cap 2002-2006/07-Decision*, 1 November 2001.

Therefore it did not allow a provision for additional IDC. The Commission maintains that it cannot question the policy of the jurisdictional authorities.

Hence, consistent with the draft decision, the Commission did not include the IDC requested by ElectraNet in its application.

4.5 Optimisation

4.5.1 ElectraNet's application

ElectraNet claims that at the time of determining the jurisdictional asset base a number of assets were considered to be redundant and therefore removed from the asset base. This process is called optimisation. However some of those assets have now become necessary due to significant changes in generation and increase in peak-load growth.

ElectraNet therefore engaged SKM to conduct an optimisation review as of 1 July 2001. SKM identified a number of previously optimised assets, with a depreciated value of $12.9 million, should now be readmitted to the regulatory asset base.

4.5.2 Meritec's review

While Meritec's noted that there was little in the way of justifications given in the SKM report for the optimisations suggested, Meritec believed that the proposed optimisation of $12.9 million was appropriate.

4.5.3 Submissions by interested parties

EUAA supported the Commission's treatment in the draft decision of not re-admitting the assets previously optimised.

ElectraNet argued that while the jurisdiction had made a judgment about optimisation at the time the jurisdictional asset base was established, this judgment was no longer applicable. Significant load growth and new generation connections since that time meant that assets that were previously optimised out of the RAB are now being used and should justifiably be reinstated in the RAB.

More generally, ECCSA and EUAA believe that the Commission's continued use of an ODRC valuation method is inappropriate. EUAA believes that the use of ODRC substantially inflates the RAB above any reasonable level and exposes transmission users to inflated prices. EUAA also notes that ODRC values adopted by governments around Australia have exposed energy users to network prices derived from assets that are up to 300 per cent above the valuation of similar non-regulated companies.

ECCSA claimed that the Commission had not removed the impact of the GST from the asset roll-forward, which would result in an inflated RAB of more than $50 million. ECCSA notes that the Commission must remove the impact of the GST according to its own price exploitation guidelines[37] and Treasury rulings. (The Commission had removed it in its draft and final decisions.)

4.5.4 Commission's consideration

In determining the jurisdictional asset base SKM was engaged to conduct an optimisation review, which resulted in a $25 million reduction in depreciated replacement cost in the RAB. Since that time the South Australian transmission system has experienced significant load growth and new generation connections which have resulted in some of those assets previously optimised now being necessary. SKM, engaged by ElectraNet found that the net effect of the review was re-admission of optimised assets of the value of $12.9 in the RAB in 2001.

In the draft decision the Commission preferred not to exercise its discretion to value the opening RAB. However, having reviewed the matter in the light of the submissions to the draft decision the Commission agrees that while the jurisdiction may have made a judgment about optimisation at the time the jurisdictional asset base was established, that judgment clearly no longer applies.

Therefore consistent with the approach adopted in the Commission's Victorian transmission networks draft decision and the DRP, the Commission has reinstated $12.9 million for the value of previously optimised assets.

4.6 Conclusion

The Commission has determined that the value to be attributed to ElectraNet's (opening) asset base as at 1 January 2003 is $824 million, being the value established by the jurisdiction as at 1 July 1999 rolled forward with the inclusion of $12.9 million for assets previously optimised.

Table 4.1 Proposed roll forward schedule for ElectraNet 1998-99 to 1 January 2003

	1998-99 ($m)	1999-00 ($m)	2000-01 ($m) [3]	2001-02 ($m)	Jul-Dec 2002 ($m)
Opening asset base	678.983	688.052	751.305	771.570	803.128
Capital expenditure [1]	24.016	64.921	7.798	40.885	26.181
Economic depreciation [2]	(14.947)	(1.667)	(0.486)	(9.327)	(5.560)
Readmitted assets			12.953		
Closing asset base	688.052	751.305	771.570	803.128	823.749 [4]

1. Net of disposals.
2. Straight line depreciation less inflation.
3. GST effect of 2.5 per cent has been removed from the CPI.
3. For the sake of comparison ElectraNet asked for $1069 million and Meritec recommended $997 million.

[37] Price exploitation and the New Tax System, ACCC, March 2000

5 Capital expenditure

5.1 Introduction

This chapter explains the Commission considerations in determining ElectraNet's capex allowance. It notes that alternatives to capex can include increases in opex, demand-side management and new generation. Therefore the Commission must consider whether or not ElectraNet has struck an appropriate balance between these alternatives.

The Commission is aware that some judgment is needed to decide whether a particular expense should be treated as capex or opex. It is mindful of the need to differentiate between ongoing opex and asset renewals (replacement and refurbishment).

5.2 Code requirement

The Commission's task in assessing ElectraNet's capex is specified in the code. In particular, part B of chapter 6 of the code requires that:

- in setting the revenue cap, the Commission must consider the potential efficiency gains in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards
- the regulatory regime seeks to achieve an environment that fosters efficient use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment.

To undertake its task, the Commission needs to make informed decisions on the adequacy, efficiency and appropriateness of the capex planned by ElectraNet to meet its present and future service requirements. The Commission has therefore engaged Meritec to review ElectraNet's proposed capex allowance. The results of Meritec's review are summarised in section 5.4.

Under the code, the Commission is removed from the network planning process. That process is now primarily the responsibility of the networks as a result of the introduction of the Network and Distributed Resources code changes.[38]

5.3 ElectraNet's proposed program

ElectraNet has forecast a $374 million ($409 million in nominal terms) capital investment program for the regulatory period to upgrade its network in order to:

- keep pace with independent forecasts of growth in electricity demand
- support new generation developments, including wind farms

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[38] ACCC, *Network and Distributed Resources*, 15 February 2002.

- support new interconnector developments, including SNI and an upgrade to the existing Heywood interconnector
- replace technologically obsolescent assets to ensure the ongoing reliability of the transmission network.

ElectraNet considers that its investment program will lower wholesale electricity prices in South Australia, ensure long-term network reliability and provide other flow-on impacts for the South Australian economy. It believes that these benefits will far outweigh the small increase in transmission costs involved.

ElectraNet adopted a probabilistic approach to determine its capex requirement due to the uncertainties involved in forecasting future customer demand and generation and interconnection developments. It engaged ROAM Consulting to identify plausible generation, demand and interconnector scenarios over a 10-year period. The scenarios identified and their assessed probabilities are set out in appendix 1.

The outcome of the probabilistic capex forecasting approach is a probability weighted average capex requirement for each year of the regulatory period as shown in table 5.1. The amounts represent the capex on assets forecast to come into service and to be rolled into the regulated asset base in each year of the regulatory period.

ElectraNet forecasts its total capex requirement during the regulatory period to be $374 million (including a provision for interest during construction).

Table 5.1 ElectraNet's probability weighted average capex requirement (real)

	Jan-Jun 2003 ($m)	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	2007-08 ($m)	Total ($m)
Lines	0.1	29.0	18.1	39.7	17.2	30.5	134.6
Substations	3.3	50.5	53.5	37.2	58.4	28.3	231.2
Other	0.9	2.0	1.3	0.4	1.6	1.7	7.9
Total capex	**4.3**	**81.5**	**72.9**	**77.3**	**77.2**	**60.5**	**373.7**

5.4 Meritec's capex report

5.4.1 Meritec's key findings

The Commission engaged Meritec to analyse and comment on the appropriateness of ElectraNet's capex program and the probabilistic method. Its conclusions follow.

- ElectraNet has an established capex planning process, which identifies new or increased load/generation requirements and models their impact on the network. The process also takes into account the review of different possible solutions, leading to a recommendation of a preferred option. Planning criteria are applied based on code requirements. ElectraNet's planning processes are sound and consistent with transmission network planning practices elsewhere.

- ElectraNet’s approach to identifying and prioritising its refurbishment and replacement expenditure is sound and is based on an appropriate assessments of the age of the equipment, its condition and its operating conditions.

- The probabilistic approach used by ElectraNet is sound, the scenarios considered are appropriate and that, in general, the probabilities applied to project timing are appropriate.

- The project cost estimates developed by ElectraNet are generally appropriate and the total costs forming the capex program are within the bounds of accuracy of the estimating method, that is, less than 5 per cent overall.

- Analysis of the different development scenarios and their associated probabilities shows that the main driver for capex is load growth. ElectraNet’s approach to forecasting load growth is fair and reasonable and in accordance with industry practices.

- There is a potential risk of ElectraNet being unable to deliver the proposed capital expenditure program. This is due to large increases in electricity network expenditure nationally and the resulting increase in competition between electricity network service providers for limited resources. Meritec notes that this may be further compounded by delays associated with the regulatory approvals process for specific projects.

- The percentage of ElectraNet’s transformers, circuit breakers and transmission lines aged 35 years or older is 50 per cent, 37 per cent and 50 per cent respectively. Meritec considers that these figures support ElectraNet’s contention that a significant number of its assets are approaching the end of their nominal life.

- A number of changes to the capex forecast proposed by ElectraNet are recommended. Meritec calculates the impact of these changes is to reduce the program, in nominal terms, from $374 million to $336 million.

Meritec recommends that ElectraNet’s proposed capex program should be accepted, subject to the above adjustments.

5.4.2 Review of major projects

As part of the review Meritec obtained a report listing all projects ElectraNet anticipates carrying out before June 2008.[39] A summary of the major proposed projects (i.e. greater than $10 million), their total estimated cost, their probability of proceeding before 2008 and their probability weighted cost is in appendix 2.

Meritec examined several major projects that ElectraNet proposes for roll-in during the regulatory period to obtain a better understanding of their drivers. Meritec’s analysis of three of these projects is in appendix 3.

[39] ElectraNet SA, *Network Analysis and Development Department, Regulated Projects Report*, 15 April 2002.

5.4.3 Meritec adjustments to ElectraNet's proposed capex program

Meritec recommends that a number of adjustments be made to the capex forecast proposed by ElectraNet. The changes are:

- the inclusion of refurbishment and some replacement expenditure as capex, when it had been presented as operating expenditure in ElectraNet's application (as directed by the Commission)
- adjustment of the probabilities associated with the load forecast from 20 per cent likelihood of a low forecast and 80 per cent of a medium forecast, to 25 per cent and 75 per cent respectively
- removal of a number of specific projects.

Treatment of refurbishment and replacement expenditure

Meritec notes that ElectraNet has decided to treat several refurbishment and replacement projects (such as transmission line rating upgrades) as opex in their application, to avoid the risk that these are not recognised when the network's assets are revalued at the next regulatory reset. Meritec notes that:

- often in the past, such expenditure would have been treated as capital by TNSPs
- treatment of costs in the way proposed by ElectraNet will result in customers incurring the full costs of those works over the regulatory period, instead of a charge for WACC and depreciation if they were capitalised
- if these costs were to be allowed as opex then some mechanism would be required to ensure that the resulting enhancements to the assets involved were not included as an increase in their value during subsequent asset base revaluations.

During its review the Commission directed Meritec to treat and assess ElectraNet's replacement and refurbishment expenditure as a separate capex item rather than as opex. Consequently, Meritec's capex report includes \$62 million of refurbishment and replacement projects that ElectraNet sought to have assessed as part of its opex forecast.

Probabilities associated with load forecast

ElectraNet's probabilistic capex program is based on a load forecast. The forecast used by ElectraNet is NEMMCO's 10 per cent probability of excedence demand forecast from its 2001 Statement of Opportunities. ROAM, on behalf of ElectraNet, assessed the relative probabilities of the low, medium and high 2001 NEMMCO forecasts to be 25 per cent, 60 per cent and 15 per cent respectively. Meritec notes, however, that in developing its probabilistic capex program that ElectraNet has used only the low and medium demand forecasts with 20 per cent and 80 per cent probabilities respectively.

Meritec has recommended that the probabilities applied to the various load forecasts be adjusted from ElectraNet's to ones more consistent with those developed by its consultant, that is 25 per cent probability of a low forecast, and 75 per cent probability of a medium forecast. Meritec calculates that this adjustment has the effect of reducing the capex allowance by approximately $12 million (2001-02) over the regulatory period.

Removal of capex allowance for certain projects

Meritec has recommended that the following projects be excluded from the capex program proposed by ElectraNet.

Augmentations to the Riverland network

Project 1.36 *Monash-Robertstown 275kV and Monash 275/132kV substation*

Meritec notes that this project has a total cost of $44.7 million comprising $9.8 million for a 275/132kV substation at Monash, and $34.9 million for a 275kV line from Monash to Robertstown. ElectraNet assigned this project a probability of 80 per cent of proceeding within the regulatory period.

Both ElectraNet and the ESIPC have identified a need to augment the supply to the Riverland area due to ongoing load growth. Meritec notes that this can be provided either by support from Murraylink (an unregulated interconnector between Victoria and South Australia) or by establishing a new 275/132kV injection point in the area. ElectraNet considers that by summer 2004-05 Murraylink will have insufficient capacity to support the existing 132kV Riverland network and as such have proposed the construction of a 275/132kV substation at Monash by 2004-05.

Meritec notes that, as the NEMMCO approved version of SNI goes directly to Robertstown and does not pass through Monash, ElectraNet has allowed for the construction of a 275kV connection from Robertstown to Monash by 2004-05. Meritec makes the following points in relation to this proposal.

- If a network support contract can be negotiated with the operators of Murraylink, then this can provide an adequate supply to the Riverlands area until 2007-08 when Murraylink may experience voltage limits and outages

- An additional 275/132kV injection point is required in 2007-08. ElectraNet has proposed the Monash 275/132kV substation for this purpose, albeit earlier in the regulatory period.

- ElectraNet’s proposed 275kV connection from Robertstown to Monash has a length of 160 km. In its submission to ESIPC, TransGrid (the proponent of SNI) have proposed a connection into SNI closer to Monash involving the construction of only 20 km of dual circuit line. This is a robust technical solution that would be significantly less expensive than constructing a line from Robertstown to Monash.

Based on the above Meritec recommended that:

- the substation component of Project No. 1.36 should be allowed, but deferred until 2007-08, based on the use of Murraylink to support the network until then

- the Robertstown to Monash 275kV line component of Project No. 1.36 should be excluded on the basis that TransGrid's proposal for diverting SNI to Monash is technically robust and less expensive than the ElectraNet's alternative.

Project 1.52 Monash-SA border component of SNI

Meritec found that ElectraNet had included a project covering the section of SNI from the South Australian border to Monash in their capex program. This project has an estimated cost of $30.9 million and a probability of 45 per cent of proceeding within the regulatory period ($13.9 million roll-in value). ElectraNet envisages that the project would begin in 2003-04 and be rolled into the capital asset base in 2004-05 or 2005-06. Meritec notes, however, that at present TransGrid is the proponent of SNI and as such there is currently no requirement for funding from ElectraNet.

Augmentations to facilitate connection of distributed generation

Meritec notes that ElectraNet has proposed substantial expenditure to facilitate the future connection of distributed generation, primarily wind-driven. These projects are listed in appendix 4. These augmentations total $185 million, but based on the probabilities assigned by ElectraNet have an expected value of $38 million during the regulatory period. The probabilities of the projects proceeding in the regulatory period range from 12-40 per cent.

In its report Meritec questions whether, given the fact that generation of this nature is the catalyst for such high levels of expenditure, these augmentation projects should be funded by customers or by the proponents of the distributed generation proposals. Meritec believes that there is a risk that economic signals to the generators regarding their location would be lost if such expenditure is allowed.

Meritec recommends that investment ElectraNet has nominated as necessary for the connection of distributed generation be excluded from its capex forecast on the basis that if there is no other need for it, then it should be largely funded by the proponent. Meritec also notes that all of the proposals relating to wind generation have relatively low probabilities of proceeding within the regulatory period.

Other contingency amounts

Meritec identified two cases where ElectraNet has allowed contingency amounts for work that has not yet been identified. These were Project No. 5.10-*Projects not identified* and Project 7.21-*Other ETSA Utilities Connection Work from 2007-08*. Meritec considers these contingency amounts to be inconsistent with the probabilistic approach. It states that although it is known that not all of the events included in the probabilistic forecast will occur, it is this principle that provides for such contingencies. As such Meritec recommends that the Commission exclude these contingency amounts from ElectraNet's capex allowance.

Table 5.2 contains a complete listing of the projects that Meritec recommends be excluded from ElectraNet's forecast capex.

Table 5.2 Projects recommended by Meritec for exclusion

Project Number	Description	Roll in ($m)	Reason
Robertstown/Monash/SNI			
1.36b	Robertstown-Monash 275kV	27.910	Not required due to SNI connection
1.52	SNI Monash to VIC Border	13.840	Funded by TransGrid
Augmentation to facilitate the connection of distributed generation			
1.33	Eyre Peninsula	22.140	Wind generation driven
1.44	South East 3rd 275kV line to Tungkilla	12.970	Wind generation driven
1.47	Split Cult-Davenport	0.960	Wind generation driven
1.48	Mintaro Brinkworth 132kV uprate protection[1]	0.002	Generation driven
1.49	Mintaro Waterloo 132kV uprate protection[1]	0.002	Generation driven
1.53	Black Range	3.200	Wind generation driven
Other contingency amounts			
5.10	Projects not yet identified	2.500	Contingency not consistent with probabilistic method
7.21	Other ETSA Utilities work	5.000	
Total Exclusions		**88.523**	
The part project below was included, however deferred from 2003/04-2004/05 to 2007-08			
1.36a	Monash 275/132kV substation	7.840	Required by 2007-08
Total Deferrals		**7.840**	

Source: Meritec capex report
1. Appeared in ElectraNet's application as opex.

5.4.4 Meritec's recommended capex allowance

As can be seen in table 5.3 Meritec has recommended a total capex allowance for ElectraNet over the regulatory period of $352 million ($384 million in nominal terms).

Table 5.3 Meritec's adjusted capex forecast (real $m)

	Jan-Jun 2003 ($m)	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	2007-08 ($m)	Total ($m)
Construction capex	4.3	56.2	47.2	64.4	64.8	37.3	274.2
Refurbishment[1]	6.8	14.8	14.3	14.1	14.3	13.2	77.4
Total capex	**11.1**	**71.0**	**61.5**	**78.5**	**79.1**	**50.5**	**351.6**

Source: Meritec capex report
1. Appears as opex in ElectraNet's application.

5.5 Submissions by interested parties

5.5.1 Responses from interested parties

Cost impact of program

Several interested parties highlighted the significant size of ElectraNet's capex program. They noted that once rolled-in, the program would add approximately 40 per cent to the initial regulated asset base which ElectraNet is seeking, and over 50 per cent to the rolled forward jurisdictional asset base over the regulatory period. They were also concerned about the cost impact of the program on end-users, especially large end-users.

Lack of detail provided in ElectraNet's application

A number of parties considered that ElectraNet's application was not supported by adequate detail to allow them to properly assess it. In particular they consider that it contains little information on: the costs of and benefits flowing from individual projects; the proportion of new investment versus replacement expenditure; and the relationship between current local capacity and forecast local growth.

Pool price benefits of program

NRG notes ElectraNet's arguements that additional investment is partially justified on the basis of relieving network constraints and delivering a lower pool price. NRG notes that a recent boundary analysis undertaken by NEMMCO has identified few network constraints in the South Australian region and that the pool price separation between South Australia and Victoria has declined dramatically in recent years.

Ageing asset profile

NRG notes that asset life alone cannot be taken as a reliable indicator of the need for asset replacement and that greater reliance should be placed on network performance over time. It considers that only limited evidence has been presented to suggest that network performance and reliability levels have deteriorated significantly or are reasonably expected to do so in the near future to justify the level of capex proposed.

Lack of information on load growth

ECCSA seeks greater information on load growth by location and current capacity at each location to substantiate the need for the capex program.

EAG is also concerned that although load growth is put forward as a major driver of network investment that ElectraNet's application fails to show what the costs of load growth are in terms of the total projected capital expenditure.

Generation developments

AGL considers that no allowance for expenditure to support generation connection should be made and that ElectraNet should use the provisions of the code to recover the costs of those augmentations from generators.

NRG considers that the impact of forecast wind generation developments on network investment needs to be closely scrutinised as only a proportion of the proposed projects would actually reach the market over the regulatory period.

Allowance for planning and consultation processes

NRG is concerned that insufficient time has been allowed in the capex program for the applicable planning and consultation processes (to qualify for regulated status) and that this may result in some projects being delayed until after the regulatory period.

Insufficient consideration of alternatives

NRG is concerned that insufficient allowance has been made for alternatives to transmission augmentation, such as distribution augmentation, generation, demand-side measures and unregulated alternatives.

Importation of fossil fuelled generated electricity

The Conservation Council believes that regulated funding should not be provided to enable the import into South Australia of highly greenhouse intensive electricity from NSW and Victorian coal-fired generators.

5.5.2 ElectraNet's response to submissions by interested parties

Application provides little detail

ElectraNet accepts that its application does not provide detailed information concerning its proposed capex program. However, it states that the Commission's consultant has reviewed all of the information and included the relevant findings in its capex report.

Probabilistic approach

ElectraNet notes that it has applied a probabilistic approach to determine a capex allowance for each year of the regulatory period and that this approach is based on an underlying set of network projects. It notes that these projects are consistent with the information recently published by the ESIPC in its 2002 Annual Planning Report.[40]

Checks and balances on planned investments

ElectraNet states that before any capital projects are built they will have to pass the regulatory test and undergo the public consultation processes required by the code. It believes that this process provides the necessary checks and balances to ensure that its investments are prudent and efficient and that non-network options are properly considered. It also notes that any capex underspend would be clawed back by the Commission at the end of the regulatory period.

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[40] ESIPC, *Annual Planning Report*, 15 July 2002

Ageing asset profile

ElectraNet refutes the suggestion that its ageing asset profile is the primary justification for its capex program. It states that most of its capex requirement is driven by load growth and the requirement to maintain service standards.

Pool price benefits of the program are limited

ElectraNet's response to a claim from interested parties that the pool price benefits of the proposed capex program are limited is that NEMMCO's boundary review identified enough constraints to justify a draft recommendation of an additional region within South Australia. It also notes that the regional boundary review relies on historical data and committed projects while ElectraNet is required to take a forward looking perspective when assessing network requirements.

5.6 Submissions in response to Meritec's capex report

5.6.1 Interested parties' responses to Meritec's capex report

Size of the proposed program

ECCSA has no view about the amount of capex that should be included in the forward revenue calculation as long as the amount of capex rolled forward has been demonstrated to be prudent and efficient.

Treatment of refurbishment expenditure

ECCSA states that ElectraNet wants to include some capex as part of the opex program, as it is on this basis that the capex will be automatically accepted as a fully recoverable cost. ECCSA states that capex must not be treated as opex.

Load growth

ECCSA is concerned about the planned massive investment program for such a relatively small amount of increase in load growth. It states that ElectraNet and Meritec make no attempt to identify where the growth is expected in the system relative to where expenditure is being targeted.

Probabilistic planning process

NRG states that while statistically defensible it is unclear whether the averaging process inherent in the probabilistic planning approach might be disproportionately influenced by extreme scenarios.

Exclusion of distributed generation projects

NRG considers that while negotiated charges paid by generators for the required augmentations will form part of the annual regulated revenue requirement, the exclusion of this expenditure appears appropriate because of the mutual exclusivity associated with competing generation proposals and the fact that network users would bear the uncertainty attached to these proposals if these projects were to be included in the ElectraNet's capex forecast.

Risk of non-delivery of program

NRG notes Meritec's concerns about the ability of ElectraNet to deliver the proposed capex program, the magnitude of the increase in ElectraNet's capex levels over historical levels and the risk of subsequent clawback. NRG considers that the preceding concerns suggest the need for conservatism and caution in the approval of a large step-increase in capex. It also believes that in view of these issues the exclusion of the expenditure proposed by Meritec is appropriate.

Augmentations to the Riverlands area

Monash-Robertstown line and related substation works (Project No. 1.36)

TransEnergie notes that ElectraNet is seeking to include $44.7 million in its capex program to augment capacity to supply the Riverland area. It states that this is based on evidence of ongoing load growth in the Riverland and several reviews undertaken by ESIPC. TransEnergie believes that the project should not be included in ElectraNet's capex program because the necessary support can be provided by the Murraylink interconnection (through a network support agreement) in combination with the existing network.

TransEnergie also notes Meritec's recommendation that the substation component ($9.8 million) of this project can be deferred until 2007-08 based on the use of Murraylink to support the network. TransEnergie, however, believes that two important factors indicate that Murraylink, in combination with a network support agreement and relatively low cost capital expenditure can adequately supply the Riverland until 2012-13.

Monash to South Australian Border Component of SNI (Project No. 1.52)

TransEnergie fully supports the conclusion of Meritec regarding this project. It believes that, as the proponent of SNI, TransGrid should eventually seek funding for the project.

5.6.2 ElectraNet response to Meritec capex report

Probabilities associated with load forecasts

ElectraNet states that recently published figures in NEMMCO's 2002 Statement of Opportunities (SOO) show that the current 10 per cent probability of exceedence forecasts are significantly higher than the forecasts used by ElectraNet in developing its capex requirements. It states that on average demand forecasts are 190 MW higher in each year of the regulatory period and therefore its proposed capex program is conservative. ElectraNet considers that Meritec's recommendation to give additional weight to the low demand forecast and less to the medium scenario is inconsistent with the current increase in demand forecasts and should be rejected.

Treatment of refurbishment and replacement expenditure

ElectraNet considers that it has proposed a prudent level of asset refurbishment and replacement expenditure in its application. It states that Meritec has reviewed in detail and generally endorsed the proposed expenditure. ElectraNet states that its proposed treatment of this expenditure is consistent with Powerlink's current practice which was effectively endorsed by the Commission in its 2001 Queensland revenue cap decision and is based on advice from asset valuation specialists SKM.

ElectraNet considers that if refurbishment expenditure is capitalised then it will be subject to revaluation risk. As such ElectraNet has decided to treat its refurbishment and replacement expenditure as opex to avoid this risk.

ElectraNet states that simply moving asset refurbishment and replacement expenditure from opex to capex without a firm guarantee that it can recoup this expenditure will prevent it from making the expenditure. It considers that this would have a serious detrimental impact on customer service and transmission network reliability.

Removal of capex allowances for certain projects

Augmentations to the Robertstown/Monash/Berri network

ElectraNet believes that the Robertstown to Monash 275kV line component of Project 1.36 should not be excluded from the capex allowance. It states that it entered into a Heads of Agreement with TransGrid on 4 June 2002 under which ElectraNet is to build, own and operate the Robertstown to Monash section of SNI. ElectraNet states that this project has passed the regulatory test and is due for commissioning in 2004-05. Hence ElectraNet believes that funding should be provided to enable this project to proceed in accordance with the code.

Augmentations to facilitate the connection of distributed generation

ElectraNet states that the probabilistic approach it has adopted to determine its proposed capex requirement explicitly takes into account the uncertainty associated with the proposed projects. It considers that the projects have been assigned relatively low probabilities and hence only a small proportion of the estimated total project costs has been included in the proposed capex allowance.

ElectraNet states that excluding the projects altogether as Meritec has recommended amounts to saying that there is a zero probability that any of these projects will proceed during the regulatory period. ElectraNet does not believe this to be the case and considers that an allowance must be made for the eventuality that one or more of these projects will proceed.

ElectraNet states that generators will be required to pay a negotiated charge for the proposed augmentations to the network thereby preserving economic signals regarding their location. It also states that the revenue recovered from these charges must be incorporated into its revenue cap. ElectraNet therefore believes that an allowance must be made for the cost of these projects in its capex allowance. It states that it will not commit expenditure that has not been allowed for in its revenue cap.

5.7 Submissions on the draft decision

5.7.1 General comments

ElectraNet does not seek an increase in its capex allowance unless adequate funding is provided. It states that the revenue stream in the draft decision will not even allow it to fund the lower level of capex proposed by the Commission.

ElectraNet believes that the draft decision would force it to take a minimalist approach to investment and find ways of cutting capex below the levels allowed by the Commission. It considers that the draft decision does not provide adequate incentives for investment.

The EAG questions why Victorian capex needs are significantly lower than that for South Australia.

The EUAA questions whether the Commission has adequately assessed the proposed capex as the draft decision is only $33 million less than the total requested. Moreover, the Commission's draft decision provides no detailed analysis of ElectraNet's past capex programs, no attempt to assess their efficiency and no assessment of the efficiency of ElectraNet's future capex proposals.

Transend disagrees with the Commission's exclusion of contingency amounts from ElectraNet's capex. It believes that this will force TNSPs to include all possible scenarios in the future (including those with extremely low probabilities). A contingency allowance is a more practical approach.

5.7.2 Probabilistic capex forecasting

The ECCSA is critical of ElectraNet's use of a probabilistic approach to forecasting its capex requirements. It believes that such an approach allows ElectraNet to request a very large amount of money to be spent over a range of non-specific projects.

The EUAA questions whether it is reasonable to allow capex proposals with a probability as low as 12 per cent as it will subject consumers to a great deal of uncertainty.

5.7.3 Clawback mechanism

The ECCSA states that the draft decision has included the bulk of the capex requested in the revenue stream and notes that the Commission will clawback any under spend. It believes that this places significant risks on both ElectraNet and consumers. It believes that the Commission must consider the additional interest earned on the unused capex funds as part of the clawback.

The ECCSA considers that ElectraNet should be required to obtain annual approval from the Commission for actual capex amounts more than has been allowed for.

Transend is concerned about a statement in the draft decision implying that the Commission would clawback regulated revenue where actual capex was less than the forecast. Transend states that the Commission's DRP makes no reference to such a clawback mechanism and that the only adjustment for capex underspend contemplated in the DRP is a prospective one (as opposed to a retrospective adjustment) to the asset base and depreciation allowances to reflect the actual level of capex. The Commission must clarify its approach to this issue so that stakeholders are provided with clear guidance on the regulator's preferred approach.

5.7.4 Project 1.36 (Robertstown to Monash 275 kV line)

ElectraNet states that the documentary evidence clearly shows that all the line works associated with SNI, including taking the line right up to Monash, were explicitly included in the project approved by NEMMCO. It states that this point has been confirmed with the ESIPC.

ElectraNet considers that the Robertstown to Monash line should be added to its capex. However, it is unwilling to make this investment unless the final decision provides adequate incentives, including a revenue stream that is sufficient to fund the total level of capex required without adversely affecting the financial viability of the business.

TransGrid considers that the NEMMCO SNI decision did include the Monash to Robertstown augmentation.

TransEnergie supports the Commission's decision to exclude the construction of a Robertstown to Monash line and a Monash to SA border line. It states that ESIPC has confirmed that Murraylink has enough power transfer capacity to provide the necessary level of support to the Riverland until at least 2007-08. It also states that revised load figures show that the load levels that previously occurred in 2007-08 do not now occur until after the summer of 2009-10 and that the installation of shunt capacitors for enhanced reactive support could defer the proposed ElectraNet works by a further two years (i.e. five years in total).

EUAA note that TransGrid's proposal has passed the regulatory test and the potential benefits that could be delivered to SA consumers by improved interconnection. EUAA's view is that the Commission must find a way to ensure that its final decision does nothing to frustrate construction of a key network element that would deliver considerable benefits to end-users in both the short and long term.

5.7.5 Monash substation component of Project 1.36

TransEnergie asks that the Commission exclude rather than defer the $9.8 million Monash substation component of Project No. 1.36.

5.7.6 Augmentations required for the connection of distributed generation

Transend rejects the Commission's argument for excluding projects to facilitate distributed generation. It states that regardless of the costs and uncertain benefits of the projects, the Commission should not pre-empt the assessment of whether projects will pass the regulatory test. Transend also believes that the code is clear about who should pay for such augmentations. It states that beneficiaries pay and currently that is customers. Transend considers that the reprioritisation of the capex program is not a real solution and that any necessary adjustment should be made to the project probabilities.

Hydro Tasmania considers that the Commission must provide a suitable capex provision within ElectraNet's revenue cap to augment the Eyre Peninsula transmission to allow connection of distributed generation. It believes that this will facilitate new generation and transmission infrastructure benefiting South Australia and the nation.

5.7.7 Treatment of refurbishment expenditures

ElectraNet notes that the Commission directed in its draft decision that approximately \$62 million of refurbishment costs be capitalised. It does not agree that \$23.5 million of these costs can be capitalised because that would be contrary to accounting standards and inconsistent to the approach it took in its Powerlink revenue cap decision.

Powerlink considers that the draft decision is not consistent with accounting standards or the approach adopted by the Commission in its revenue cap decision.

Transend believes that the Commission should not get overly prescriptive and that any treatment of refurbishment should be cost-neutral in the long term.

The EUAA endorses the Commission's treatment of the refurbishment projects.

5.8 Commission's considerations

5.8.1 Removal of capex allowance for specific projects

Project No. 1.36 (Robertstown to Monash line and substation works)

In its application ElectraNet included the Robertstown to Monash line and associated substation works to maintain adequate voltage levels in the Riverland area. Subsequent to the completion of Meritec's capex review, ElectraNet advised the Commission that it had entered into a Heads of Agreement with TransGrid to build, own and operate a Robertstown to Monash component of SNI. It considered that as this project had passed the regulatory test it should be included in its capex allowance. In its draft decision, the Commission excluded the Robertstown to Monash line component of Project 1.36 because the Commission was uncertain whether or not this version of SNI was the one approved by NEMMCO as passing the regulatory test.

In relation to the substation component of Project 1.36 the Commission noted in its draft decision that given the uncertainty regarding supply issues to the Riverland and the technical nature of the proposals put forward, the Commission relied on the advice of its expert consultant. Therefore the Commission accepted Meritec's recommendation that the substation component of Project 1.36 should be included in ElectraNet's capex allowance but deferred until 2007-08 based on the use of network support arrangements up until that time.

Based on the information it has received, the Commission is now satisfied that Project 1.36 forms part of the SNI project approved by NEMMCO and recently upheld by the National Electricity Tribunal (NET). As noted earlier TransGrid and ElectraNet have entered into a Heads of Agreement that ElectraNet is to build, own and operate the Robertstown to Monash component of the SNI project. As such the Commission considers that Project 1.36 (both line and substation works) should be included in

ElectraNet's capex allowance for completion in 2004-05 (the year which was found by NEMMCO to maximise the benefits of SNI) with a probability of 80 per cent of proceeding in during regulatory period. Based on this probability Project 1.36 has a probability weighted cost of $35.8 million.

The Commission has assigned a probability of 80 per cent because it understands that TransEnergie (the owner of Murraylink) has appealed the NET's decision.

Project 1.38 (Heywood interconnector augmentation)

ElectraNet advised the Commission that, in light of the NET's SNI decision, it had reassessed the Heywood interconnector augmentation project and decided to reduce the probability of it proceeding within the regulatory period from 64 to 12 per cent. This reduces the expected cost of this project from about $21 million to $4 million.

Project No. 1.52 (Monash to South Australian border component of SNI)

Meritec recommended that Project No.1.52 be removed from ElectraNet's forecast capex program as TransGrid was the proponent of SNI. However, subsequent to Meritec's capex report being finalised ElectraNet advised that it had entered into a Heads of Agreement with TransGrid to build, own and operate the Robertstown to Monash component of SNI. Nevertheless, as TransGrid is to build own and operate this element of the SNI Project, the Commission considers that it is not appropriate for it to include Project 1.52 in ElectraNet's capex allowance.

Augmentations to facilitate connection of distributed generation

ElectraNet's application included a number of augmentations to facilitate the connection of distributed generation (primarily wind) at a total cost of $185 million. However, based on the probabilities assigned to them by ElectraNet (12 to 40 per cent) they have a total expected value $38 million during the regulatory period. These projects are proposed for construction late in the regulatory period, with most occurring in the final year of the regulatory period - ie 2007-08.

The Commission notes the concerns of interested parties regarding its decision to exclude augmentations required to facilitate the connection of distributed generation from ElectraNet's capex allowance. However, consistent with its draft decision the Commission considers that these projects should be excluded from ElectraNet's proposed capex program for the following reasons.

- The high cost of such projects while their economic benefits are unclear. Given their high value the Commission considers that it is likely that they would have a significant impact on transmission prices but provide uncertain customer benefits.

- The code is unclear about who is to actually pay for such augmentations. While generators are required to negotiate with a TNSP about how much they pay for required augmentations to the shared network, the amount they will actually negotiate may not reflect the true cost imposed by the generator.

- Locational signals may be lost if generators are not required to pay for all or a substantial amount of the augmentation required as a result of them being connected to the shared network.

The Commission also considers that the size of ElectraNet's program provides it with enough scope to reprioritise should one of these generation projects actually proceed.

Based on the above, the Commission has excluded these projects from ElectraNet's capex allowance.

Other contingency amounts

Meritec identified two cases where ElectraNet allowed contingency amounts for work that has not yet been identified. These were Project No. 5.10-*Projects not identified* and Project 7.21-*Other ETSA Utilities Connection Work from 2007-08*. The Commission agrees with Meritec's conclusion that an allowance for contingency amounts is inconsistent with the probabilistic capex planning approach. It therefore accepts Meritec's recommendation that these contingency amounts be excluded from ElectraNet's capex allowance.

5.8.2 Treatment of refurbishment and replacement expenditure

During the review the Commission directed Meritec to treat all refurbishment works ($77.4 million) as a separate capex item. Meritec analysed the refurbishment and identified $15.3 million of this as opex and recommended that it be treated as such. These 'other associated refurbishment projects' include modifying existing assets in some minor way that will ensure that the asset performs as it was originally designed. The Commission accepted this recommendation but required the remaining refurbishment expenditure ($62.1 million) to be treated as capex.

ElectraNet and several other TNSPs argued that the risk of optimisation, compliance with accounting standards and consistency require that these refurbishments be treated as opex.

In its draft decision the Commission considered that refurbishment expenditures should be capitalised for the following reasons.

- Benefits of refurbishment are gained over a long period of time. By expensing refurbishment ElectraNet exposes its customers to a one-off impost in that year rather than a charge for WACC and depreciation if they are capitalised.

- If these costs were to be allowed as operating expenses then some mechanism would be required to ensure that the resulting enhancements to the assets involved were not included as an increase in their value during subsequent asset base reviews. If the refurbishment work is expensed it would be very difficult to identify the amount in the future. In contrast, capitalising leaves an audit trail in the form of an asset record. This is important during future valuations.

- Under the building block approach opex is treated as an allowance with limited opportunity to clawback. There would be significant difficulties in monitoring actual amounts spent on refurbishment, under the light-handed approach adopted by the Commission, if they are treated as an expense.

- Similar refurbishments have been capitalised by ElectraNet and its predecessors (the previous owners of South Australia's transmission business) in the past.

In response to the draft decision ElectraNet claimed a further $24 million (of the $62 million capitalised refurbishment works) be treated as opex. The Commission notes that Meritec reviewed refurbishments and recommended that only $15 million be treated as opex. The Commission has decided not to vary from its draft decision.

The Commission does, however, recognise the possible risk of optimisation. It therefore proposes to treat refurbishment as a separate line-item of capex and:

- quarantine the amount against optimisation for 10 years
- depreciate the amount over the same period, recognising that its value may be extinguished well before the life of the (original) asset.

The above treatment is subject to the condition that ElectraNet:

- reports the refurbishment expenses annually against its asset management plan
- maintains records so that the refurbishment can be identified to the asset.

The Commission considers that the above approach balances its concerns with the requirements of ElectraNet, and is a fair solution. The amount of refurbishment to be quarantined as capex under the above approach is $62.1 million.

5.8.3 Probabilities associated with demand forecasts

The Commission agrees with Meritec that an adjustment to the probabilities associated with the low and medium load forecasts would make the analysis more consistent with ROAM's analysis. It notes, however, that ElectraNet's capex program is based on the 2001 SOO load forecast and that NEMMCO's recently released 2002 SOO predicts an increase in load growth for South Australia above that predicted in its 2001 forecast. The Commission understands that, on average, load growth is 109 MW higher for the base growth forecast across the regulatory period. As a result of this change the Commission considers that the load forecasts used by ElectraNet are reasonable and therefore it does not require the probabilities applied by ElectraNet to the low and medium demand forecasts to be adjusted.

5.8.4 Analysis of ElectraNet's proposed capex program

The size and price impact of the proposed program

In many of the submissions received by the Commission interested parties raised concerns about the size of the ElectraNet's capex program, noting that it would add about 40 per cent to the initial RAB and over 50 per cent to the jurisdictional RAB. Interested parties were particularly concerned about the impact the program would have on transmission prices.

Ability to deliver the proposed capex program

In its capex report Meritec identified, as one its main conclusions, that there was a potential risk that ElectraNet would not be able to deliver the proposed capex program. It noted that ElectraNet has proposed a capex allowance of about $80 million per annum over the regulatory period, whereas historically SA transmission businesses' capex program has averaged less than $40 million per annum.

Primary to Meritec's concerns is that a number of TNSPs and distribution network service providers (DNSPs) have underway or a planning significant increases to their capex programs (and in some cases opex programs). Meritec noted that this is likely to lead to increased competition for limited resources, particularly in the areas of experienced service providers, major plant items and project management personnel. Interested parties shared Meritec's concerns.

The effectiveness of other capex controls

The Commission also shares Meritec's concerns regarding the size of the capex program and ElectraNet's ability to deliver it within the regulatory period. ElectraNet notes that there are effective controls on the capex including the regulatory test, the clawback mechanism and the risk of optimisation. However, although the controls on capex are useful, in practice there are significant limitations on their effectiveness. As such, the controls complement, rather than substitute proper assessment during the revenue cap process.

ESIPC high level review of ElectraNet's capex program

The Commission approached ESIPC, as the South Australian Government's independent expert on the electricity, to obtain its view on ElectraNet's proposed capex program. ESIPC gave the Commission a report[41] containing the results of its high level analysis of the adequacy of the state's network for the next five years. Commission staff also met with ESIPC on many occasions as part of its revenue cap consultations.

ESIPC found that the augmentations highlighted in its report closely reflected the typical augmentations anticipated for South Australia's transmission network to keep pace with customer demand growth. It notes however that, given the high level nature of its analysis and the limited project information available at the time of its review (July 2002), the technical appropriateness and cost-effectiveness of the proposed solutions have not been tested or compared against reasonable alternatives.

ESIPC considers that, within the protective framework of the regulatory test process and given the potential for project optimisation following detailed design, a forward capital investment plan in the South Australian transmission network of about $400 million (including some of the refurbishment projects) to maintain South Australia's required network performance standards is reasonable. ESIPC advised that its high level review used ElectraNet's proposed project costs, relying on the cost conclusions from section 4 of Meritec's capex report. A copy of ESIPC's report is on the Commission's website.

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41 ESIPC, *Planning Council Review of ElectraNet SA's Capital Expenditure*, 30 August 2002.

The cost of meeting load growth

In its application ElectraNet notes that most of the capex program is driven by load growth. The Commission has undertaken a rough analysis of the cost of this additional load growth and has determined it to be approximately $1000/MWh. That is, most of the capex program could be avoided if 500MW of load would accept $1000/MWh to switch off for up to 1.7 per cent of the time or if peaking generation in or near Adelaide could be attracted into the market at that price.

5.8.5 Conclusion

On the basis of its own analysis, and that of its consultant Meritec, the Commission considers that a capex program of about $358 million over the regulatory period (including $62 million of refurbishment projects) should be adequate to allow ElectraNet to meet its obligations under the code and the South Australia Transmission Code. This amount:

- is slightly higher than the amount recommended by Meritec
- takes into account the risks and practical limitations in delivering a large program
- provides incentives to prioritise projects and pursue non-network options.

Consequently, for the purposes of determining ElectraNet's revenue cap for the period 1 January 2003 to 30 June 2008, the Commission has included a capex allowance of $358 million as set out in table 5.4. This decision is made on the basis of ElectraNet's proposed project commissioning dates and includes an allowance for IDC calculated using 8.30 per cent, which represents the nominal vanilla WACC as set out in chapter 3 of this decision.

Table 5.4 ElectraNet's capex allowance ($m real)

	Jan-Jun 2003	2003-04	2004-05	2005-06	2006-07	2007-08	Total
Construction capex	4.3	56.8	76.2	67.1	57.0	34.9	296.3
Refurbishment	5.4	11.4	11.6	11.5	11.6	10.5	62.0
Total capex	**9.7**	**68.2**	**87.8**	**78.6**	**68.6**	**45.4**	**358.3**

In making this decision the Commission notes that ElectraNet must apply the regulatory test to each project to justify its inclusion in the RAB. The Commission will re-consider these matters during the next regulatory review. The Commission also flags its intention to test the validity of ElectraNet's capex forecasts throughout the regulatory period through its Information Requirements Guidelines.[42] These guidelines contain provisions requiring the annual reporting of actual capex figures.

[42] ACCC, *Information Requirements Guidelines - Decision*, 5 June 2002.

6 Operating and maintenance expenditure

6.1 Introduction

In setting ElectraNet's allowed revenue, the Commission must assess ElectraNet's capacity to achieve realistic efficiency gains in its proposed opex. Because opex represents a large proportion of a network's variable costs, it is an important source of savings and productive efficiencies. An important focus of the Commission's assessment is benchmarking.

6.2 Code requirement

The Commission's task in assessing ElectraNet's opex is specified in the code. In particular, part B of chapter 6 of the code requires that:

- in setting the revenue cap, the Commission must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account expected demand growth and service standards
- the regulatory regime must seek to achieve efficiency in the use of existing infrastructure, efficient operating and maintenance practices, and an efficient level of investment.

6.3 ElectraNet's proposal

6.3.1 Key factors in determining ElectraNet's opex proposal

ElectraNet states that it has taken into account the following factors in arriving at its proposed opex allowance.

Opex efficiency

ElectraNet states that it has instituted a number of work practices, processes and systems that are best practice. These include:

- outsourcing of non-core business activities through competitive tendering and performance based contracts
- deployment of best practice maintenance techniques
- introduction of a continuous remote asset monitoring system for key assets
- leveraging 'off-the-shelf' operational asset information systems
- a comprehensive computerised asset management system that is remotely accessible by service providers
- consistent use of risk management tools in decision making.

ElectraNet considers that the cost savings of these initiatives are implicit in its present cost structure and that minimal further efficiency gains can be achieved.

Ageing asset profile

ElectraNet states that 24 per cent of its assets are currently over 40 years old. It argues that failure to increase expenditure now by reinvesting in the network will have a detrimental impact on transmission network reliability in the future. It refers to a number of charts to illustrate that the number and duration of system failures have increased in recent times.

ElectraNet states that it commissioned a study to analyse reliability trends over the last five years. It states that the study revealed an increase in the frequency of equipment failure resulting in supply interruptions for greater than 0.2 minutes. ElectraNet believes that the results of this study confirm that the age-related decline in reliability of these assets has already started and that this situation needs to be addressed through asset refurbishment or replacement of aged assets.

Benchmarking

Network benchmarking

ElectraNet has taken part in the International Transmission Operations and Maintenance Study (ITOMS) involving all Australian and New Zealand TNSPs and about 15 international TNSPs. It claims the 1999 study showed it as a leading performer in terms of low costs and high service levels. It also claims that the 2001 study showed that whilst its cost efficiency was still high, its service level indicator had dropped dramatically. [43]

ElectraNet considers that the reason for the fall in service levels is due primarily to substations. It argues that this indicates a need for additional expenditure over and above current regulatory allowances, particularly in the area of substations and that this explains its provision for replacement and refurbishment of ageing assets. ElectraNet argues that the EPO made an insufficient allowance for asset replacement and refurbishment and that this has resulted in the network deteriorating and subsequently the need for substantial reinvestment.

Non-network benchmarking

ElectraNet notes that there is little comparative data available because of differing company-specific characteristics. It claims that the best comparative benchmarking study available was undertaken by the Essential Services Commission (ESC) for Victorian distributors, which benchmarks at the sub-function level. ElectraNet considers this to be directly comparable with its operations and states that the study found its non-network costs to be 25 per cent below the benchmark level.

[43] ElectraNet SA, *Transmission Network Revenue Cap Application 2003-2007/08,* 16 April 2002 (p. 8-9)

ElectraNet states that a number of factors need to be considered when comparing its network with others. It considers that it has:

- an extremely peaky load profile, which drives investment but has a very limited cost recovery
- the lowest load profile duration in Australia (i.e. the top 25 per cent of demand occurs for less than 4 per cent of the time; a system maximum demand of 2850 MW for an energy throughput of only 12.4GWh)
- low load density (5600 km lines and 68 substations to service the states population of 1.5 million (with only 0.4 million living outside Adelaide))
- a large geographical area which increases maintenance costs (ElectraNet has a service delivery area of approximately 200 000 square km)
- an ageing network (with an average asset age of 28 years)
- a high dependency on the South Australian-Victorian interconnector during peak periods which requires maintenance to be undertaken out-of-hours at much higher costs
- the most prescriptive customer reliability standards with the need to comply with both the code and the South Australian Transmission Code.

6.3.2 Operational expenditure categories

ElectraNet's application contains the following opex categories.

Network maintenance

ElectraNet states that its network maintenance expenditure was determined taking into account the growth in assets and changes in work practices to maintain customer service levels.

Monitoring and control

ElectraNet states that the key cost driver in this category is the deferment of expenditure on aged assets and the requirement to improve reliability and reduce associated risk. The proposed expenditure includes the installation of equipment and systems that provide an early warning of changes in the condition of assets.

Network refurbishment

ElectraNet considers that it has ageing assets as a result of a lack of investment in the past. It believes that it has applied a pragmatic and rigorous approach using risk management techniques to prioritise the assets to be replaced. ElectraNet is proposing a total average replacement and refurbishment expenditure of 1.5 per cent of asset replacement value over the regulatory period.[44] It considers that this amount is below the 2-2.5 per cent long-term average expenditure required or the 4 per cent that would be required to replace all assets over 40 years.

Corporate support

ElectraNet considers that benchmarking studies (see section 6.3.1) show that its corporate costs are efficient. It states that it will continue to build on efficiencies and economies of scale and absorb higher costs driven by an increase in the size of the business.

Risk management

ElectraNet states that it carries out an annual business risk review to identify and quantify risk, and apply appropriate risk control measures. Independent consultants are engaged to review ElectraNet's treatment of business risk. ElectraNet states that it faces a number of risks, some of which are common to TNSPs and others that insurers perceive to be much greater (for example, bushfire risk). It also notes that over recent years insurance premiums have been steadily increasing.

Imposed costs

ElectraNet states that this component includes costs that are imposed by regulators, government and by law. It states that grid support contracts have been implemented where it is determined that they are more economical or practical than a network solution.

Proposed pass-through costs

ElectraNet's application proposes that several costs be treated as a pass-through if and when they eventuate. It considers that it is potentially exposed to the following:

- additional contracted grid support services
- material increases in ElectraNet's operating costs or risk exposures resulting from future NEM changes including firm access
- a change in the way or rate at which tax is imposed on ElectraNet
- catastrophic events that either exceed ElectraNet's insurance cover and deductible limit or for which insurance is unavailable and for which insufficient provision is made in the revenue cap
- changes to service obligations, ODRC guidelines or other requirements imposed on ElectraNet through changes in the regulatory requirements.

[44] ElectraNet SA, *Transmission Network Revenue Cap Application 2003-2007/08* (p. 8-13), 16 April 2002.

6.3.3 Opex allowance proposed by ElectraNet

ElectraNet's proposed opex allowance is contained in table 6.1. ElectraNet considers that the resulting cost increases are moderate over the regulatory period and mainly due to the increase in the asset base.

Table 6.1 ElectraNet's proposed opex allowance

	Jan-Jun 2003 ($m)	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	2007-08 ($m)	Total ($m)
Network maintenance	9.3	18.9	19.4	19.8	20.3	20.6	108.3
Monitoring and control	4.7	6.8	6.9	6.8	7.0	7.0	39.2
Refurbishment	6.8	14.8	14.3	14.1	14.3	13.2	77.5
Corporate costs	4.1	8.3	8.3	8.3	8.3	8.3	45.6
Risk management	4.3	8.9	9.3	9.6	9.9	10.1	52.1
Imposed costs	6.8	13.3	13.1	12.8	12.9	12.3	71.2
Total opex	**36.0**	**70.8**	**71.2**	**71.5**	**72.6**	**71.5**	**393.6**

6.4 Consultant's report

The Commission engaged Meritec to review ElectraNet's proposed opex requirements. The following section outlines Meritec's main findings and recommended opex allowance.

6.4.1 Summary of Meritec's findings

The main findings of Meritec's opex review are that:

- ElectraNet has an established, robust asset management planning process, which is sound and consistent with transmission network asset management practices elsewhere
- ElectraNet's ability to show significant efficiency gains between years within a given regulatory period is limited because of the nature of the business and the type of assets involved. However, ElectraNet should be able to show efficiency gains between regulatory periods particularly after several years have passed
- the allowance sought for grid support should be accepted on a 'pass-through' basis
- compliance costs associated with the NEM appear to be reasonable and should be allowed on a pass-through basis
- based on the information provided to Meritec, it appears that imposed costs such as licence fees and levies are already included in existing operating expenditure and have been removed
- in line with the Queensland revenue cap decision, hedging costs, which are imposed costs, should not be allowed

- when compared to previous reported opex, several items of operational expenditure proposed by ElectraNet appear to have been accounted for in more than one location and therefore have been removed

- refurbishment originally included by ElectraNet under opex has been considered as capex, resulting in an immediate reduction of $62 million of the proposed opex over the regulatory period

- most of opex is associated with the maintenance and operation of existing assets. However a small portion is related to the operation and maintenance of new assets (Meritec estimates that for every 5 per cent change in the capex budget a 0.024 per cent change in the same direction should occur in the opex budget).

6.4.2 ElectraNet's capitalisation policy

ElectraNet's capitalisation policy establishes ElectraNet's expenditure/capital definition. The definition of a unit of plant forms ElectraNet's basis for determining whether expenditure should be categorised as opex or capex.

In its application ElectraNet expensed all costs incurred on parts of the unit, while the entire unit was capitalised. Should a new unit be required, or a unit of greater capacity is needed, then it is treated as capital. Costs incurred in restoring the unit to full service or to prevent deterioration are expensed as per ElectraNet's capitalisation policy.

Meritec disagrees with this definition. It notes that the effect of this policy, if implemented, could be that any refurbishment less than the unit of property would have to be expensed.

6.4.3 Meritec's assessment of benchmarks

Meritec believes that ElectraNet's asset age profile is not older than other network companies in Australia and New Zealand. However it considers that over the next 10 to 15 years a significant proportion of assets will need replacement as they fail or become difficult to maintain. It notes that, for some assets, ElectraNet may be able to extend their productive lives (beyond their nominal life).

Meritec states that TNSPs need to be compared on a number of indicators for benchmarking purposes and that no one measure is adequate. It considers that even then only general comparisons can be made and various factors need to be considered. In general Meritec notes that opex costs will be lower for companies with higher GWh, lower line length, lower number of transformers and substations and reduced peak demand.

Meritec notes that the ITOMS benchmarking studies referred to in ElectraNet's application indicates that after a period of satisfactory results ElectraNet's service levels have started to decline while its expenditure levels have remained similar to that of other TNSPs. Meritec considers that this could be due to ageing assets or external factors. It believes that results over several periods would need to be considered to determine the exact cause of the decline in ElectraNet's service levels. Meritec does not consider that a comparison of ElectraNet to non-TNSPs is particularly relevant when reviewing the appropriateness of ElectraNet's opex levels.

As part of its benchmarking exercise, Meritec compared ElectraNet and other TNSPs using several opex ratios (opex divided by asset value, peak demand, annual power transmitted and line length). Meritec used its recommendation, ElectraNet's historical data and ElectraNet's application for this exercise. (The Commission notes that the historical opex figures for TransGrid included financing costs of $75 million, whereas financing costs were not included for Transpower or ElectraNet. The Commission considers that this has distorted Meritec's analysis.)

Meritec believes that ElectraNet has historically been spending less on opex than other network companies (see above for distortion in Meritec's analysis) but that its requested amount may be too high. Overall Meritec considers that its recommended opex is reasonable and points out that its declines (as a percentage of the asset base) over the regulatory period.

6.4.4 Meritec's assessment of opex categories

Meritec stated that it was unable to compare individual cost items in ElectraNet's opex forecast with its historical figures, due to a lack of detailed breakdown of costs.

Meritec also stated that a line-by-line comparison of individual cost items among TNSPs was not useful because of the differences among networks. Therefore Meritec took a holistic approach and analysed ElectraNet's total opex and trend.

Details of Meritec's assessment of individual opex categories form part of the opex report. This report is available on the Commission's website.

6.4.5 Meritec's recommended opex allowance

Table 6.2 contains Meritec's recommended opex allowance for the regulatory period.

Table 6.2 Meritec recommended opex allowance

	Jan-Jun 2003 ($m)	2003-04 ($m)	2003-04 ($m)	2003-04 ($m)	2003-04 ($m)	2007-08 ($m)	Total ($m)
ElectraNet's proposal[1]	36.0	70.8	71.2	71.5	72.6	71.5	**393.6**
Refurbishment[2]	(5.4)	(11.5)	(11.6)	(11.5)	(11.6)	(10.5)	**(62.1)**
Net opex	30.6	59.3	59.6	60.0	61.0	61.0	**331.5**
Meritec's proposal[3]	**22.2**	**44.4**	**44.3**	**44.7**	**45.2**	**45.5**	**246.3**

1. Includes $4 million per annum of grid support (except for Jan-Jun 2003, which includes $2 million of grid support).
2. Refurbishment that has been capitalised.
3. Includes $2 million per annum of grid support (except Jan-Jun 2003, which includes $1 million of grid support).

6.5 Submissions by interested parties

6.5.1 Lack of detail

Several submissions commented that there was inadequate information to substantiate the doubling of opex over historical levels. ECCSA and the EAG state that there needs to be greater breakdown of the 'regulated opex forecast'. They also state that the proposed figures are not benchmarked against current expenditure levels or against similar enterprises.

6.5.2 Historical operational expenditure

A number of submissions note that ElectraNet has requested a much higher opex allowance compared to its historical expenditure. EUAA and ECCSA note that in the 1998, 1999 and 2000 annual reports of the South Australian transmission business its opex was $41 million, $41 million and $34 million respectively. However they believe that ElectraNet is asking for $71 million per annum with little information or data to substantiate its claims, other than it is required to sustain a reliable network.

WMC notes that the South Australian Transmission Code, issued by the ESCoSA in October 1999, establishes a target level of opex equivalent to $12.47/MW of maximum demand. When GST is taken into account, this results in an annual figure of $38.4 million. WMC considers that ElectraNet's proposal represents an 82 per cent increase over this level.

AGL states that while ElectraNet argues that the level of opex under the EPO was unsustainably low, ESCoSA reported that ElectraNet spent less in this area than the base amount in the EPO and that this underspent amount contributed to an award of $1 million under the performance incentive scheme. AGL considers that the actions of ElectraNet in 2000-01 appear to be inconsistent with their current claims.

6.5.3 Benchmarking

WMC and EUAA assessed the reasonableness of ElectraNet's opex by undertaking their own benchmarking analysis. Both considered that, irrespective of the ratios used, ElectraNet's proposed opex was excessive.

ECCSA notes that ElectraNet has provided one benchmark study to demonstrate its need for an increase in opex (i.e. the ITOMS benchmarking study). It considers that care is needed in using just one benchmark study, when other benchmarks indicate that ElectraNet's performance may be inadequate.

ECCSA also states that ElectraNet refers to a benchmarking study of Victorian distribution networks and rail systems and from this concludes that it compares well to these businesses. It considers that ElectraNet should be compared to similar or equivalent Australian and overseas transmission companies.

ECCSA acknowledges that ElectraNet must meet certain reliability standards but believes that ElectraNet has not demonstrated that the efficiency of its operating performance has exceeded those of other TNSPs.

6.5.4 Differences in network characteristics

ECCSA states that while a peaky load profile has an impact on the size of the network it has little impact on the opex required. Because of the similarities of ElectraNet's network to other Australian TNSPs, ECCSA considers that ElectraNet can compare its opex levels with other TNSPs depending on what network factor is being considered.

6.5.5 Relationship between opex and capex

ECCSA states that the prime reason for capex is to reduce opex.

NRG considers that the additions of new assets to the asset base will not create a need for additional maintenance expenditure to the same extent that would be required for older existing assets.

6.5.6 Pass-through costs

ECCSA believes that ElectraNet needs to indicate how it managed risks and costs noted in the pass-through section previously.

NRG also comments on a number of ElectraNet's proposed pass-through costs.

6.5.7 Reliability/cost trade-off

NRG believes that there needs to be a balance between improved reliability and cost, recognising the inherent trade-off. It considers that ElectraNet's application focuses exclusively on reliability, at the expense of cost efficiency and value for money.

6.6 ElectraNet's response to submissions by interested parties

6.6.1 Increase in refurbishment expenditure

Several submissions comment that other TNSPs also have similar network ageing issues and thus question why ElectraNet needs a step increase in refurbishment expenditure. ElectraNet states that other TNSPs have historically spent at a higher level on asset reinvestment. It also notes that it has changed its treatment of this expenditure from capex to opex, which increases its opex figure.

ElectraNet also considers that its own review of leading performance indicators, in conjunction with international benchmarking results, shows a declining trend in reliability which ElectraNet argues must be addressed by responsible refurbishment plans.

6.6.2 Impact of low load profile

ElectraNet argues that its low load profile affects its opex requirement, as the network is built to accommodate peak demand. It states that more assets are required in South Australia per unit of energy throughput (MWh) compared to other networks with a higher load profile, leading to higher maintenance costs.

6.6.3 Impact of EPO on opex

Several submissions consider that historical expenditures should factor heavily in determining future allowances. ElectraNet states that it inherited the previous owner's asset management plan via the EPO and associated Performance Incentive (PI) scheme. ElectraNet considers that the EPO drove transmission prices artificially low by omitting allowances for critical capital and operating expenses. It also states that the effect of underspending in maintenance and refurbishment are becoming apparent in the leading indicators of network performance, and thus increased expenditure is needed. It considers that it has developed a comprehensive asset management plan that will provide a sustainable level of supply reliability for its customers.

6.6.4 Changes to ElectraNet's operating environment

ElectraNet states that the many changes to the environment in which it is operating have affected its operating costs. These include a change in the economic regulator and the changing rules that came with it, changes in TNSPs responsibilities and risks in the NEM and higher insurance costs.

6.6.5 Relationship between opex and capex

ElectraNet states that the vast majority of capex is required to meet load growth and to remove network constraints. It believes that capex will increase the size of the network and the number of assets to be maintained, operated and managed. As a result ElectraNet believes that opex requirements will increase rather than decrease.

6.6.6 Benchmarking

ElectraNet argues that comparisons of cost ratios between different TNSPs must reflect cost drivers such as load profile, load density, jurisdictional regulatory requirements, asset age profile, the level of outsourcing and different accounting treatments.

A number of submissions criticise the validity of conducting a benchmarking study of non-network costs using the Victorian ESC Distribution Pricing Review benchmarks. ElectraNet argues that this is the most applicable and independent benchmarking study that has been carried out for regulated network businesses in Australia.

6.7 Submissions by interested parties on Meritec's opex report

6.7.1 Treatment of refurbishment expenditure

ECCSA states that much of the opex increase from previous years is due to ElectraNet including significant amounts of capex under the opex allowance. It believes that Meritec is correct to exclude capex from the approved opex budget.

Powerlink notes that the Commission has directed that the refurbishment expenditure be removed from the opex budget and be included in the capex budget instead. It considers this is a fundamental change in a key regulatory principle and has the following undesirable consequences:

- it encourages TNSPs to replace entire assets rather than refurbish sub-components
- it encourages TNSPs to change the level at which a 'unit of plant' is defined to a much more micro level to reduce revaluation risk (but increasing administrative costs)
- it will make it necessary for TNSPs to keep a separate set of regulatory asset accounts, because a broad policy of capitalising all refurbishment works is not compliant with accounting standards.

Powerlink considers that the Commission's approach seems to be a material deviation from the approach adopted from its previous revenue cap decision relating to Powerlink and from accepted accounting practices. It believes that this will introduce a level of regulatory risk, which will lead to a loss of investment in transmission assets.

Powerlink states that the level at which the unit of plant is defined is crucial to avoid revaluation risk. This is because expenditure that has been capitalised for a sub-component of a unit of plant is likely to be missed during an asset valuation on the unit of plant. This would result in the TNSP not being fully compensated for its refurbishment investment.

Powerlink states that revaluation risk can only be managed by adopting a much smaller unit of plant definition. However, it states that the process of asset valuations becomes more complex and costly when assets are defined at a micro level. It believes that additional costs would be incurred from desegregating a project into much more detail for financial and maintenance registers and the subsequent management of those registers.

Powerlink does not consider that the capitalisation of all asset refurbishment is supported by Australian accounting standards.[45] It states that if the Commission changes its policy to impose an approach that does not conform to the accounting standards, then TNSPs would be forced to carry a separate set of books for regulatory purposes. Powerlink cannot see that the benefits to the network outweigh the extra cost this would involve.

Transend's view is that ElectraNet has a legitimate case for revising its capitalisation policy to avoid revaluation risk. It believes that it is important that the Commission adopts an approach that provides transmission companies with appropriate incentives and ensures consistency between regulatory decisions.

Transend notes that the Commission accepted the advice of PB Associates that certain renewal and refurbishment expenditure should be treated as opex in the Powerlink decision. However in relation to ElectraNet it states that Meritec reaches a contrary conclusion. It notes that Meritec disagreed with ElectraNet's approach to using a unit of plant definition as the basis for determining whether something was opex or capex. Transend has reservations about Meritec's argument and believes that treating all refurbishment work as capital would discourage renewal of an asset's components because the expenditure would not be recouped.

Transend put forward several possible solutions to address this issue, including less frequent valuations of the asset base and providing a guarantee that replacement and refurbishment expenditure will be separately recognised and included in the RAB.

6.7.2 Benchmarking

ECCSA considers that Meritec has undertaken benchmarking of ElectraNet's opex in a marginal fashion resulting in little meaningful comparison. It states that if the Commission accepts that such minimal benchmarking is enough for it to fulfil its

[45] Statement of Accounting Concepts 4 and Australian Accounting Standards Board 1021.

obligations, then it has failed in its primary responsibility to implement the 'competition by comparison' aspect of regulatory control. ECCSA believes that the only way to either prove or disprove ElectraNet's claims is through wide and eclectic comparisons of performance and costs, which it believes ElectraNet and Meritec have both failed to do.

6.8 ElectraNet's response to Meritec's opex report

6.8.1 Findings of the Meritec Report

ElectraNet claims that Meritec endorsed its proposal for direct operational costs (i.e. asset maintenance, monitoring and control) and asset renewals and refurbishment). However, it believes that Meritec's recommendation for significant cuts in the area of non-network operational costs (i.e. corporate costs, risk management and costs imposed by the regulatory environment) is unfounded. ElectraNet states that there has been no double counting of items in the opex allowance it has proposed and that Meritec reached this conclusion because of incorrect assumptions made in the process of mapping the proposed opex allowance to outdated historical costs that were reported against different cost categories.

6.8.2 Meritec's method

ElectraNet considers that comparing the proposed opex allowance for the regulatory period with the reported historical opex contained in Transmission Lessor Corporation's 2000 Annual Report is problematic. ElectraNet states that Meritec have attempted to reconcile current costs to 1999-2000 historical costs, which were reported on a different basis and against different cost categories. It also considers that the assumptions made concerning material and insurance costs are incorrect.

6.8.3 Cost difference between 1999-00 and 2001-02

ElectraNet considers that the process followed by Meritec does not take into account a real cost increase of $5.8 million between the years 1999-00 and 2001-02. It states that Meritec incorrectly used 1999-00 as the base year for its assessment when it should have used 2001-02. It claims that 1999-00 was a particularly low expenditure year because the South Australian Government enforced restrictions in the lead up to the sale of the business and diverted significant resources to support both the sale process and year 2000 computer rectification activities. Therefore reduced maintenance work was undertaken in 1999-00.

6.8.4 Increases in opex over 2001-02

ElectraNet provided a breakdown of the costs included in its proposed opex, which shows an increase over and above 2001-02 cost levels. It states that its analysis supports an opex allowance of $58 million rather than the $46 million recommended by Meritec. ElectraNet considers that its analysis shows that even if only those cost items recognised by Meritec are included, Meritec's recommendation of $46 million must be increased to $49 million to correct the errors in Meritec's assumptions. ElectraNet believes that Meritec appears to have assumed the new cost items sought by ElectraNet were double counted because Meritec's reconciliation process failed to recognise increases in underlying costs between 1999-00 and 2001-02.

6.8.5 Cost items ElectraNet claims have been omitted

ElectraNet also considers that Meritec has omitted several substantial cost items to the value of $8.7 million per annum. It states that these were removed with little or no justification other than they did not reconcile with Meritec's base cost model. ElectraNet considers that these items represent real costs that must be incurred by ElectraNet and that they should be included in their opex allowance.

6.8.6 Pass- through costs

In relation to NEM imposed costs ElectraNet considers that these costs are known and that pass-through should only be applied to external costs beyond its control. It therefore considers that its NEM imposed costs should be included directly in its opex allowance and not as a pass-through item.

6.8.7 Treatment of refurbishment expenditure

ElectraNet notes that Meritec endorses its proposed expenditure on asset refurbishment but that the Commission directed it to treat this expenditure as capex when most of it was included as opex in its application. ElectraNet states that the Commission's direction has been made without any justification or reference to the current practices of other TNSPs, accounting standards or the appropriateness of capitalising this expenditure. It also states that a detailed review of the refurbishment expenditure has subsequently identified $23.5 million of the refurbishment works over the regulatory period must be expensed and not capitalised to comply with accounting standards.

6.8.8 Concluding remarks

ElectraNet states that the Commission and interested parties must recognise that the cost items Meritec has inadvertently excluded from their recommended opex allowance and those that were specifically excluded represent real costs that must be incurred by the business. It believes that failure to include these costs will simply reduce the funds available to make the expenditures on asset maintenance, monitoring and control, asset renewals and refurbishment to the detriment of customer service and reliability.

6.9 Submissions on the draft decision

6.9.1 General

ElectraNet states that it is facing comparatively higher operating costs than previous years. It considers that failure to make an adequate opex allowance in the final decision will simply reduce the funds available for asset maintenance, monitoring and control, asset renewals. It states that this would reduce customer service and reliability and result in increased future maintenance costs.

ElectraNet states that 75 per cent of its total opex costs is based on competitive market prices. It believes that there is no better way of getting a competitive price; hence there is little scope for further efficiency improvements.

The EAG is concerned over ElectraNet's growing focus on its outsourcing of maintenance activities and the impact that this has on skill levels in the industry. It notes that ElectraNet's application makes no commitment to develop skills to ensure that South Australian customers end up getting a long-term reliable supply.

The EUAA believes that the historical trend for opex appears to be downward sloping, yet the draft decision allows a large step increase which is contrary to overseas experience (actual opex declines overtime with efficiencies). The EUAA believes that this leaves end-users exposed to excessive prices and that it undermines end-user support for the Commission and its incentive regulation approach.

Transend considers that actual business conditions need to be taken into account in setting opex.

The ECCSA states that Australia is supposed to have an incentive-based regime for regulated businesses. However, by allowing ElectraNet to maintain its current level of opex, the Commission is not imposing any incentive on ElectraNet to find ways to improve its performance. It considers that information provided by past annual reports, ElectraNet's submissions to ESCoSA and benchmarking indicate that the amount for opex proposed by the Commission in its draft decision is significantly above the historical average. The ECCSA believes that the opex allowance should start at past levels and be automatically reduced on an annual basis by at least the CPI to replicate true competitive pressures.

6.9.2 Amounts reported under the PI Scheme

ElectraNet is concerned about statements in the draft decision about the PI scheme and the apparent misunderstanding concerning both the nature and relevance of the PI scheme opex costs to determining ElectraNet's opex allowance for the forthcoming regulatory period. It states that opex costs reported for the purpose of PI scheme are not the same as regulated opex and cannot validly be used as a guide to establishing ElectraNet's opex allowance for the regulatory period.

6.9.3 Historical operational expenditures

ElectraNet considers that operating costs in the years before 2001-02 were not typical of the costs required to operate the stand-alone transmission business in South Australia. Hence they cannot be relied on as a guide to establish ElectraNet's opex allowance. It believes that Meritec's reliance on 1999-00 costs is flawed and that adjusting for actual costs in 2001-02, the opex allowance, even based on Meritec's recommended cost items, should be $44.5 million (excluding grid support) compared with the $43 million allowed in the draft decision. Further ElectraNet considers that the $44.5 million does not allow for cost items that Meritec inappropriately omitted.

6.9.4 Benchmarking

ElectraNet believes that the Commission has adopted a tough approach to its draft decision based on an incorrect perception that its costs are high and inefficient. It believes that when factors such as differences in operating environments and scale are taken into account its costs are efficient.

Transend believes that the Commission needs to develop a rigorous framework for benchmarking which examines the individual cost components. It also believes that the Commission must also disclose any weightings assigned to particular benchmarks.

The ECCSA considers that international benchmarking is a key tool of regulators following the light-handed approach to demonstrate ‘competition by comparison’. It states that the Commission does nothing to require ElectraNet to provide any international benchmark cost comparisons.

The EUAA believes that the Commission must set challenging benchmarks for ElectraNet’s opex but sees little evidence of that in the draft decision.

6.9.5 Opex efficiency dividend

ElectraNet considers that the efficiency dividend on opex should be removed.

6.10 Commission’s considerations

The Commission uses the building block approach to determine TNSPs’ revenue caps. This is part of the light-handed incentive-based regulation preferred by the Commission. Under this approach the TNSPs are given a sum of money enabling them to earn a reasonable return when they are functioning efficiently.

The Commission is required to asses whether the opex proposed by ElectraNet is reasonable, efficient and cost effective. ElectraNet is allowed to retain any savings in opex but also bears the cost of overruns or inefficiencies.

Therefore the Commission, like Meritec, has focused on assessing a reasonable level of opex for ElectraNet. In doing so it is aware of ElectraNet’s claims that it has achieved substantial cost efficiencies as a result of pursuing best practices.

The Commission’s decision regarding a reasonable level of opex for ElectraNet is based on three main elements: Meritec’s review of opex, an analysis of historical opex, and the benchmarking of opex against other TNSPs. Each of these areas is expanded on in the following sections.

6.10.1 Meritec’s review

In reviewing ElectraNet’s opex requirements, Meritec attempted to compare costs submitted in the application with costs in previous annual reports on a line-by-line basis. However such comparison was not possible in many areas because of changes in the classification of cost categories and the lack of an audit trail linking them.

As such Meritec took a holistic approach by looking at trends in both opex categories where possible and historical opex. On this basis, Meritec recommended an opex allowance on average of about $43 million per annum (excluding grid support costs).

6.10.2 Historical operational expenditures

The Commission agrees with submissions from interested parties that the amount of opex requested by ElectraNet represents a significant increase over historical opex levels for the transmission business. Table 6.3 provides an estimate of historical opex for the transmission business that could be used to forecast future opex.

In its application ElectraNet requested an average opex of $71.5 million per annum over the regulatory period. Excluding refurbishments, (most of which have now been capitalised) and grid support (which has been identified separately), the opex amount proposed by ElectraNet was about $56 million per annum.

Table 6.3 Estimate of SA transmission businesses' historical opex

Year	Annual Report ($m)	Regulatory Accounts[3] ($m)	PI Scheme[4] ($m)
1997-98	29[1]		
1998-99	32[1]		
1999-00	32[1]		30.2
2000-01	34[2]	36.4	32.2
2001-02	35[2]	35.3	35.4
Meritec	43[5]		
ElectraNet	56[6]		

1. Annual report amounts excluding grid support and ancillary services costs ($12 million for 1997-98 and $7 million for 1998-99).
2. Regulatory accounts less grid support and one-off expenses.
3. Prescribed services only (excluding grid support).
4. Figures reported by ElectraNet to the ESCoSA under its PI scheme.
5. Average over the regulatory period, Meritec's recommendation (excludes grid support).
6. Average over the regulatory period, ElectraNet proposed (excludes grid support and refurbishment that has been capitalised)

Relevance of historical opex costs

In its final submission to the Commission, ElectraNet states that there appears to be confusion as to which historical numbers should be used as a guide to establishing its opex allowance. It notes that the Commission presents annual report figures for opex dating back to 1997-98. ElectraNet states that the figures quoted by the Commission in table 6.3 of its draft decision are misleading for the following reasons.

- The establishment of a stand-alone transmission business (as part of industry disaggregation and privatisation) required an increase in efficient opex costs. In 1997-98 the transmission business was still part of the vertically integrated ETSA Corporation and was not allocated the full cost of services provided to it. The same is true of 1998-99 (the year in which disaggregation took place).

- Base costs in 1999-00 and in 2000-01 were constrained lower than normal due to the forced reduction in opex levels by the SA Government in the lead up to the sale of the transmission business (October 2000). In the post privatisation period opex levels were kept low by the new owners as they assessed the business.

Therefore ElectraNet believes that operating costs in the years before 2001-02 were not typical of the costs required to operate the stand-alone transmission business and cannot be relied on as a guide in establishing its opex allowance. It considers that 2001-02 is the most appropriate basis for establishing its opex costs for the regulatory period. It notes that its regulated opex in 2001-02 was $39 million (however, the Commission found that this amount included grid support costs of $3.7 million).

While noting the comments of ElectraNet, the Commission still considers that the historical costs of the transmission business remain relevant to its assessment of the appropriate opex allowance for ElectraNet. It considers that although the South Australian transmission business has had a number of different organisational structures, and a change in ownership in October 2000, its operations remain fundamentally the same.

Review of ElectraNet's historical opex levels

In its draft decision the Commission indicated that it would re-examine ElectraNet's opex allowance ($43 million per annum). This was based on concerns about differences in amounts reported by ElectraNet to the ESCoSA under the PI scheme and in its regulated accounts. As the information was received just before the release of its draft decision the Commission was unable to examine the differences in detail.

In its draft decision the Commission noted that the opex reported in the transmission businesses' annual reports appeared to have been steady since 1997-98 at around $40 million per annum, both before and after the change in ownership and despite inflation and capex. In its final submission, ElectraNet states that this is incorrect and that in fact opex has risen during the period to reflect the stand-alone operation of the transmission business. It states that the 1997-98 and 1998-99 figures taken from annual reports included approximately $12 million and $7 million (respectively) of ancillary service costs for ETSA Transmission.

Since the draft decision the Commission has obtained regulatory accounts for financial years 2000-01 and 2001-02. It considers these to be more useful than annual reports as they contain ElectraNet's regulated opex amounts for these two years, rather than all opex incurred by the company. ElectraNet's regulated opex was $39.5 million in 2000-01 and $39.0 million in 2001-02. The Commission notes that these figures include grid support and a number of non-recurring expenses in 2000-01.

To assess ElectraNet's opex allowance, the Commission is primarily interested in its base level opex-that is, the normal recurring expenses incurred by the business in providing prescribed or regulated services, excluding grid support costs.

In its response to the draft decsion ElectraNet stated that opex costs reported for the purpose of the PI scheme were not the same as regulated opex and therefore cannot be used as a guide to establishing its opex allowance. It states that the costs are different because of timing differences in the reporting periods[46] and some costs being outside the scope contemplated at the time the EPO was established.

The Commission accepts that the costs reported under the PI scheme are of a different scope to those reported in ElectraNet's regulated accounts. However, it did find that

[46] The reporting period for ESCoSA's PI scheme was the year ending 31 March, whereas the annual reports cover the year ending 30 June.

ElectraNet's regulated accounts for 2000-01 contained several one-off expenses. Removing these and grid support costs from the regulated accounts results in a base level opex of about $34 million.

The Commission has also reviewed ElectraNet's regulated accounts for 2001-02. It did not identify any one-off expenses but noted that the figures included grid support. Excluding grid support, the base opex for the year is about $35 million.

In determining ElectraNet's opex allowance for the forthcoming regulatory period the Commission considers that its historical opex is one of a number of key factors that it must consider. Its analysis (excluding grid support) indicates that historical opex is in the order of $35 million, rather than the $39 million considered by both the Commission and Meritec at the time of the draft decision.

Cost increases and new cost items

As stated in its draft decision, the Commission prefers to use efficient costs, rather than actual costs. If the Commission were to adopt cost-plus regulation then the details of individual cost components would be important. However a more heavy-handed interventionist approach to verification would be required. Under its light-handed approach the Commission prefers to focus on total opex rather than individual components.

Moreover, in a cost-plus approach, all costs would have to be reviewed. The Commission notes that ElectraNet starts with a base figure of $39 million and adds the cost increases to that figure. Such an approach ignores the fact that the figure of $39 million would also include items which may have reduced.

6.10.3 Commission's benchmarking analysis

The Commission is aware that several factors limit the usefulness of comparing transmission companies. These include varying load profiles, load densities, asset age profiles, network designs, local regulatory requirements, topography, climate and accounting practices.

The Commission notes ElectraNet's argument concerning the specific characteristics of the South Australian electricity market and its impact on benchmarking. In its draft decision the Commission understood and accepted that comparisons based on a single benchmark were not very meaningful. It noted that opex/electricity transported would show ElectraNet, which has low load density, in an adverse light compared to other TNSPs. Conversely opex/number of substation would show ElectraNet, which has a relatively high number of substations, in a favourable light.

However, different ratios can provide an indication of the reasonableness of ElectraNet's opex. Therefore the Commission undertook its own benchmarking, considering several different ratios to make a general assessment of ElectraNet's proposed opex.

As noted previously the Commission considers that components such as abnormal items, financing costs, depreciation and grid support should not be included in benchmarking assessments. These could inflate or deflate the ratios and may obscure the core operational expenditures of the business.

The Commission benchmarked ElectraNet against Powerlink, SPI and TransGrid. The results of the Commission's analysis are presented in table 6.4.

Table 6.4 Ratio analysis of ElectraNet compared to other TNSPs.

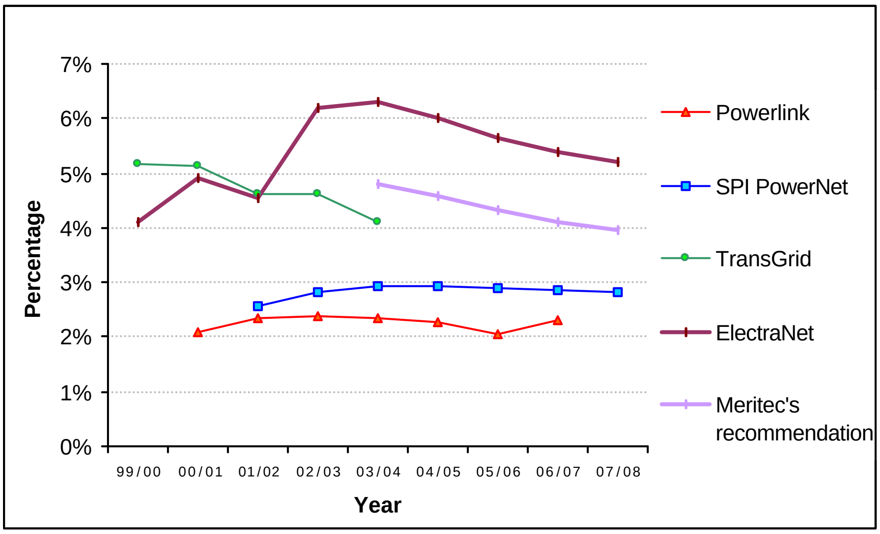
		2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Opex/line length	ElectraNet	6.42	9.10	9.93	9.96	10.04	10.22	10.22
($'000/km)	ElectraNet-Meritec recommended			7.60	7.58	7.65	7.75	7.80
	Powerlink	5.04	5.45	5.63	5.81	5.49	6.17	
	SPI PowerNet	7.07	8.00	8.56	8.68	8.62	8.71	8.79
	TransGrid	8.71	8.85	8.99				
Opex per	ElectraNet	526	746	815	816	823	838	838
Substation ($'000)	ElectraNet -Meritec recommended			623	621	627	636	639
	Powerlink	657	711	735	758	716	805	
	SPI PowerNet	1052	1191	1275	1293	1284	1298	1309
	TransGrid	1394	1417	1439				
Opex/asset base	ElectraNet	4.56	6.19	6.29	6.00	5.65	5.39	5.19
(%)	ElectraNet -Meritec recommended			4.82	4.57	4.30	4.09	3.96
	Powerlink	2.34	2.40	2.36	2.29	2.06	2.30	
	SPI PowerNet	2.58	2.82	2.95	2.94	2.88	2.86	2.83
	TransGrid	4.63	4.60	4.10				
Opex/MW peak	ElectraNet	12.56	17.80	19.43	19.48	19.64	19.99	19.99
($'000/MW)	ElectraNet -Meritec recommended			14.87	14.83	14.96	15.16	15.25
	Powerlink	8.48	9.18	9.49	9.78	9.24	10.39	
	SPI PowerNet	5.64	6.39	6.84	6.93	6.89	6.96	7.02
	TransGrid	9.21	9.35	9.50				
Opex/GWh	ElectraNet	3.00	4.26	4.65	4.66	4.70	4.78	4.78
($'000/GWh)	ElectraNet -Meritec recommended			3.56	3.54	3.58	3.63	3.65
	Powerlink	1.38	1.50	1.55	1.60	1.51	1.70	
	SPI PowerNet	0.90	1.01	1.09	1.10	1.09	1.10	1.11
	TransGrid	1.62	1.65	1.68				

Note: Refurbishments and grid support have been excluded from ElectraNet's, Meritec's recommended and Powerlink's opex figures.

Source: Powerlink opex figures from financial modelling ($real) used to develop final decision.
SPI opex figures from PB associates' *Review of SPI Operating Expenditure* ($real)
TransGrid opex figures from 25 January 2000 *NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04* decision ($nominal).
ElectraNet opex figures from application ($56m, real).
Meritec recommended opex figures from Meritec's *ElectraNet SA Operational Expenditures Review* ($43m, real).

Figure 6.1 shows ElectraNet's opex as a percentage of the asset base has been reasonable compared to other TNSPs in previous years but increases significantly above that of other TNSPs in the future. The Commission also notes that the opex amount sought by ElectraNet is similar to that of SPI and Powerlink, which have considerably larger asset bases.

Figure 6.1 Comparison of TNSP's opex per asset base



Note: Refurbishments and grid support have been excluded from ElectraNet's, Meritec's recommended and Powerlink's opex levels.

The graphs below (figures 6.2-6.4) show that ElectraNet's opex (as recommended by Meritec) is generally higher than that of other TNSPs. However, the Commission recognises that each TNSP operates a different network in a different environment. It considers that these differences may explain why ElectraNet's ratios (based on Meritec's recommended opex levels) are higher than that of other TNSPs.

Figure 6.2 Opex per GWh, per line length and per peak demand

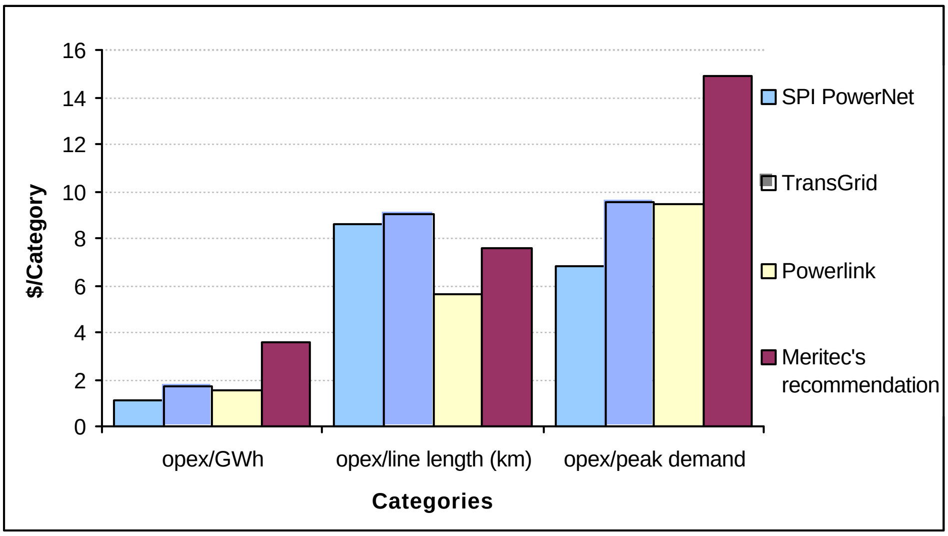


Figure 6.3 Opex per substation

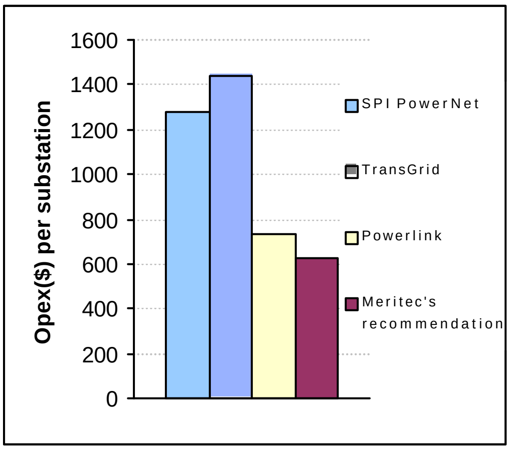
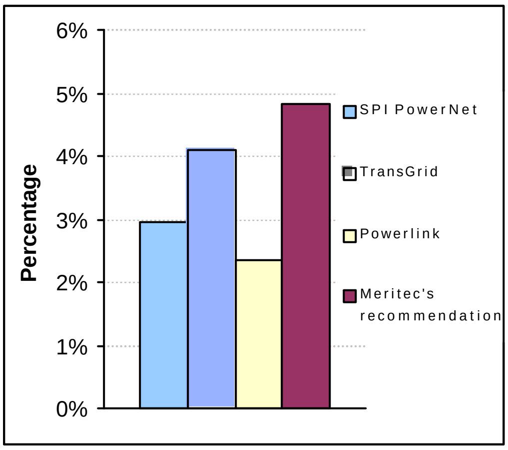


Figure 6.4 Opex/Asset base



ElectraNet gave many reasons why their network is different to other TNSPs operating in Australia. In particular it notes that it has a peaky load profile and that this has an impact on its opex requirement. The Commission understands that though a peaky load profile may require a larger asset base (due to the need to increase the capacity of the network) it has limited influence on opex.

It is possible to argue that a peaky load profile should result in a low opex/asset base ratio because:

- the network is under used most of the time making it easier to access, maintain and repair, lessening the need for live-line maintenance and out-of-hours maintenance
- the denominator will be large due to the asset base being sized for peak demand.

To demonstrate that the South Australian operating environment requires more assets to deliver the same network capacity, ElectraNet suggested that line length per MW peak and substation per MW peak should be used to assess its network and its proposed opex levels. ElectraNet states that line length per MW peak and substation per MW peak shows that South Australia requires 25 per cent larger lines than Queensland and 100 per cent more substations than Queensland to provide the same level of service to customers. Table 6.5 shows these figures.

Since the draft decision, ElectraNet has made several submissions, including an expert consultant's opinion, explaining the reasons for differences among TNSPs.

Table 6.5 Ratio Analysis of ElectraNet with TNSPs

	Powerlink	SPI	ElectraNet	TransGrid
Line length/MW peak	1.68	0.80	1.96	1.06
Substation/MW peak	0.01	0.01	0.02	0.01

The Commission notes that although ElectraNet has ageing assets, so do other TNSPs. While an ageing asset profile generally means greater maintenance, the replacement of old existing assets means that less intensive maintenance would be required for some assets.

Although the Commission’s benchmarking indicates that the opex levels recommended by Meritec are higher than the other TNSPs based on a majority of the ratios examined, this does not necessarily imply that this level of opex is inefficient. The Commission considers that the differences in operating conditions and scale may explain why the ratios are higher. However, the benchmarking shows that opex levels requested by ElectraNet in its application are very high (compared to other TNSPs and historical levels). Hence it is difficult to explain the differences as resulting from operational conditions or scale.

6.10.4 Trade-off between opex and capex

Several submissions question why, given the large increase in capex over historical levels, the need for opex would be higher. The Commission agrees that some capex will result in the need for less maintenance to be done on some assets, resulting in lower opex requirements. However, given the large increase in capex over historical levels, the Commission believes that ElectraNet will be required to maintain a greater number of assets resulting in increased opex. Overall, the Commission considers that the capex program is likely to result in a small net increase in opex. This is supported by Meritec’s analysis.

6.10.5 Opex efficiency dividend

The draft decision applied an efficiency dividend of 2 per cent per annum to ElectraNet’s operating expenses. ElectraNet states that the Commission has not applied an efficiency dividend in any of its other revenue cap decisions and that the application of the dividend appears to be based on in incorrect perception that ElectraNet’s opex costs are inefficient.

ElectraNet considers that there is little scope for further opex efficiency improvements and that the higher opex it has requested for the forthcoming regulatory period is necessary to carry out the increased volume of work required on the network. ElectraNet states that most of its total opex (75 per cent) is either fixed or based on competitive market prices. ElectraNet therefore considers that the efficiency dividend on opex should not be applied to it.

The Commission has reviewed its decision to apply an opex efficiency dividend to ElectraNet. Based on this review, and Meritec’s finding that ElectraNet’s ability to show significant efficiency gains between years within any given regulatory period is limited, the Commission has decided not to apply an efficiency dividend to ElectraNet’s opex at this time. The Commission notes, however, that Meritec considered that ElectraNet should be able to show efficiency gains between regulatory periods, particularly after a number of years had passed.[47] Therefore, the Commission flags the possibility of it introducing an opex efficiency dividend for ElectraNet at its next revenue reset.

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[47] Meritec, *ElectraNet SA Operational and Expenditure Review*, July 2002 (p.31, section 5.9).

6.10.6 Treatment of refurbishment expenditure

During its review of ElectraNet's capex, the Commission directed Meritec to consider refurbishments as part of capex ($77.4 million). However, in regard to this work Meritec recommended that some of this amount ($15.3 million) be included as opex. A more detailed discussion of the Commission's treatment of refurbishment expenditure can be found in section 5.8.2.

6.10.7 Grid support

An amount of $4 million per annum is allowed for grid support. The Commission will monitor this amount and it will be clawed back at the end of the regulatory period if it is not spent. Any requirement for grid support services over and above the $4 million per annum provided during the regulatory period will be considered by the Commission on a pass-through basis.

6.10.8 Pass-through events

ElectraNet requested that a number of potential additional costs be treated as pass-through events if and when they eventuate. In response to the draft decision ElectraNet requested that it would like to be treated similarly to SPI in terms of pass-through rules. While the Commission has some concerns about the muting effect that a pass-through mechanism has on incentives, it recognises that certain events are outside ElectraNet's control.

The Commission therefore proposes that ElectraNet develop a set of detailed pass-through rules and give them to the Commission for its consideration. Consistent with its other decisions the detailed pass-through rules may address four categories of events: a change in taxes event; a service standards event; a terrorism event and an insurance event.

However, until the Commission has approved a set of detailed pass-through rules for ElectraNet the Commission intends to be guided by the approach it outlined in its draft decision. That is, if ElectraNet can demonstrate that extraordinary contingencies have arisen, then the Commission will consider these case by case and will address them by way of a pass-through. ElectraNet will be required to obtain the Commission's approval prior to incorporating any pass-through amounts. It will also need to demonstrate to the Commission the materiality and reasonableness of such amounts.

6.10.9 Equity raising costs

As noted in chapter 3, the Commission has decided to allow ElectraNet an annual amount for equity raising costs over the regulatory period. These costs were calculated using the asset base and included in the revenue cap decision as opex. These costs, which average about $0.748 million per annum, have been included in ElectraNet's opex allowance (table 6.6).

6.11 Commission's decision regarding opex

In its draft decision the Commission allowed an opex of about $43 million per year (excluding grid support) across the regulatory period. This allowance was based on:

- a historical opex level of about $39 million (the Commission's review since the draft decision indicates that recent past figures are about $35 million)

- Meritec's recommendation of $43 million (given the time constraints, the Commission is unable to assess whether a reduction in the above opex would have made Meritec reduce this amount)

- the Commission's own benchmarking of opex ($43 million), which showed that this is on the high-side.

The Commission, however, notes that ElectraNet has claimed that it has to undertake significant 'catch-up' maintenance expenditure, amounting to on average about $4 million each year over the regulatory period. ElectraNet claims that this is a result of under-spending in previous years. The Commission is unable to verify this claim. The Commission is however aware of the importance of service quality issues in South Australia, and recognises that maintenance is an important driver of service quality.

Even though the Commission believes that a base level opex of $43 million is on the high-side it prefers to err on the side of the service provider and, for the purpose of this final decision, prefers not to reduce ElectraNet's opex further.

However, the Commission will monitor the maintenance expenditure through its annual reporting requirement. The Commission considers therefore that ElectraNet's base opex (excluding grid support and equity raising costs) should remain at $43 million.

6.12 Conclusion

After considering all of the above, the Commission considers that a figure of $48 million per annum (including $4 million per annum of grid support and $0.7 million per annum of equity raising costs) to be an appropriate opex allowance for ElectraNet over the forthcoming regulatory period (table 6.6).

Table 6.6 ElectraNet's opex allowance (Jan 2003-2007/08)

	Jan-Jun 2003 ($m)	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	2007-08 ($m)	Total ($m)
ElectraNet's proposal[1]	28.6	55.3	55.6	56.0	57.0	57.0	309.5
Meritec's proposal[1]	21.2	42.4	42.3	42.7	43.2	43.5	235.3
Equity raising costs	0.3	0.7	0.7	0.8	0.8	0.8	4.1
Grid support	2.0	4.0	4.0	4.0	4.0	4.0	22.0
Total Opex	**23.5**	**47.1**	**47.0**	**47.5**	**48.0**	**48.3**	**261.4**

1. Figures exclude grid support and refurbishment that has been capitalised.

7 Total revenue

The main elements of ElectraNet's revenue cap were discussed in previous chapters. This chapter explains the Commission's calculation of ElectraNet's allowable revenue from 1 January 2003 to 30 June 2008.

As explained in chapter 2, the Commission's role as regulator of transmission revenue is limited to determining the MAR. ElectraNet is responsible for calculating transmission network prices in accordance with chapter 6, part C of the code.

7.1 The accrual building block approach

The building block formula is:

$$\begin{aligned} AR &= \text{return on capital} + \text{return of capital} + \text{opex} + \text{tax} \\ &= (WACC * WDV) + D + \text{opex} + \text{tax} \end{aligned}$$

where:

where:	AR	=	allowed revenue
	WACC	=	post-tax nominal weighted average cost of capital
	WDV	=	written down (depreciated) value of the asset base
	D	=	depreciation
	opex	=	operating and maintenance expenditure
	tax	=	expected business income tax payable

However, in determining the MAR, the code requires the Commission to take into account the service standards that TNSPs are expected to maintain. Therefore, the Commission will adopt an annual service standard adjustment in the calculation of MAR, that is:

$$\begin{aligned} MAR_t &= (\text{allowed revenue}) + (\text{financial incentive}) \\ &= \left(AR_t\right) + \left(\frac{(AR_{t-1} + AR_{t-2})}{2} \times S_{ct}\right) \end{aligned}$$

Where:

MAR	=	maximum allowed revenue
AR	=	allowed revenue
S	=	service standards factor
t	=	regulatory period (see table 8.1)
ct	=	calender year (see table 8.1)

7.2 ElectraNet's proposal

In its application ElectraNet asked for a revenue cap of $194.5 million in 2002-03 (this amount increases to $200 million when EPO recovery costs are included), increasing to $239.9 million in 2007-08. In 2001-02 it earned $139 million (approved annually under the EPO). ElectraNet claims that this very substantial increase is mainly due to rises in:

- opening RAB due to revaluation of easements and bringing back of assets which were optimised previously (chapter 4)
- capex to cope with increased demand and to improve service reliability (chapter 5)
- opex to enhance maintenance and to accommodate cost increases (chapter 6).

7.3 Commission's assessment of building block components

7.3.1 Asset value

To establish the appropriate return on capital, the Commission modelled ElectraNet's asset base (over the life of the regulatory period) and WACC (estimated on the basis of the most recent financial information).

As explained in chapter 4, the Commission has determined the value of ElectraNet's assets as at 1 January 2003 to be $824 million.

7.3.2 Capital expenditure

As explained in chapter 5, the Commission considers that a capex allowance of $358.3 million (in real terms) over the regulatory period is reasonable for ElectraNet. This includes $62.1 million of refurbishment expenses classified as opex in ElectraNet's application.

7.3.3 Depreciation (return-of-capital)

The Commission used a straight-line depreciation method (based on the remaining life per asset class of existing assets and the standard life for new assets) to model economic depreciation. The resulting depreciation figures are shown in table 7.2.

7.3.4 Weighted average cost of capital

The Commission's estimate of ElectraNet's WACC is explained in chapter 3.

The Commission has given careful consideration to the nature of ElectraNet's business and its current financial circumstances in establishing its WACC. The Commission, however, notes that although there is a well recognised theoretical model for establishing WACC, there is less than full agreement on the precise magnitude of the various financial parameters used (table 3.6).

The Commission has applied a post-tax nominal return on equity of 11.17 per cent, which equates to a post-tax nominal WACC of 6.07 per cent.

7.3.5 Operating and maintenance expenses

As explained in chapter 6, the Commission has included an opex allowance of about $44 million per annum (in real terms) over the regulatory period. In addition, a grid support allowance of $4 million has been provided for, on the basis that any unspent amounts will be clawed back.

7.3.6 Estimated taxes payable

Tax estimates relate to the network's regulated activities only. The Commission anticipates that ElectraNet would be paying income tax during the regulatory period. This view is based on ElectraNet's tax depreciations profile. The Commission's assessment of taxes payable are based on the 60 per cent gearing assumed in the WACC parameters as opposed to ElectraNet's actual gearing. The Commission's estimates of ElectraNet's tax payments are shown in table 7.2.

7.3.7 EPO revenue adjustments

On 19 June 2002 the Commission approved ElectraNet's tariffs for the period 1 July 2002 to 31 December 2002. The EPO's rebalancing controls prevented the Commission from allowing ElectraNet to fully recover its performance incentive bonus scheme bonus and the under recovery of revenue from the previous period. ElectraNet was unable to recover the amounts shown in table 7.1.

Table 7.1 EPO revenue unrecovered by ElectraNet

	($m)
Performance incentive scheme	0.870
Under-recovery of revenue from 2001-02	2.302
Under-recovery of revenue for the period 1 July 2002 to 31 December 2002 resulting from the rebalancing control constraints	2.192
Total	**5.365**

ElectraNet has requested that $5.365 million be added to the AR over the transitional period (1 January 2003 to 30 June 2003). The Commission has allowed this amount.

7.4 Commission's considerations

The Commission proposes an unsmoothed revenue allowance that increases from $148.01 million in 2002-03 to $178.51 million 2007-08 as shown in table 7.2.

Table 7.2 ElectraNet's unsmoothed AR 2002-03 to 2007-08 (nominal)

	Jan-June 2003 ($m)	2002-03 ($m)	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	2007-08 ($m)
Return on capital	33.78	68.13	71.02	76.22	81.78	86.49	89.48
Return of capital	9.23	18.61	21.16	24.15	25.48	28.86	25.00
Operating expenses	28.82	48.17	49.17	50.18	51.22	52.29	53.37
Estimated taxes payable	9.28	15.47	16.86	18.71	20.14	22.15	21.32
Value of franking credits	4.64	7.73	8.43	9.35	10.07	11.07	10.66
EPO under recovery		5.365					
Unadjusted revenue allowance	**81.04**	**148.01**	**149.78**	**159.91**	**168.56**	**178.71**	**178.51**

7.5 Conclusion

The actual revenue earned by ElectraNet for 2001-02 was about $139 million based on the EPO. ElectraNet estimates that its earnings for 2002-03, based on the EPO, would be around $144 million.

The Commission has determined a revenue allowance for ElectraNet that increases from $148.01 million in 2002-03 to $180.38 million in 2007-08, as shown in table 7.3. The decision is based on forecast inflation and applies a smoothing factor of minus 1.96 per cent.

This decision allows ElectraNet to adjust the opening revenue figure of $148.01 million by actual inflation (the eight weighted capital city CPI).

Table 7.3 ElectraNet's smoothed AR, 2002-03 to 2007-08 (nominal)

	2002-03 ($m)	2003-04 ($m)	2004-05 ($m)	2005-06 ($m)	2006-07 ($m)	2007-08 ($m)
Smoothed AR	**148.01**	**153.98**	**160.19**	**166.66**	**173.38**	**180.38**

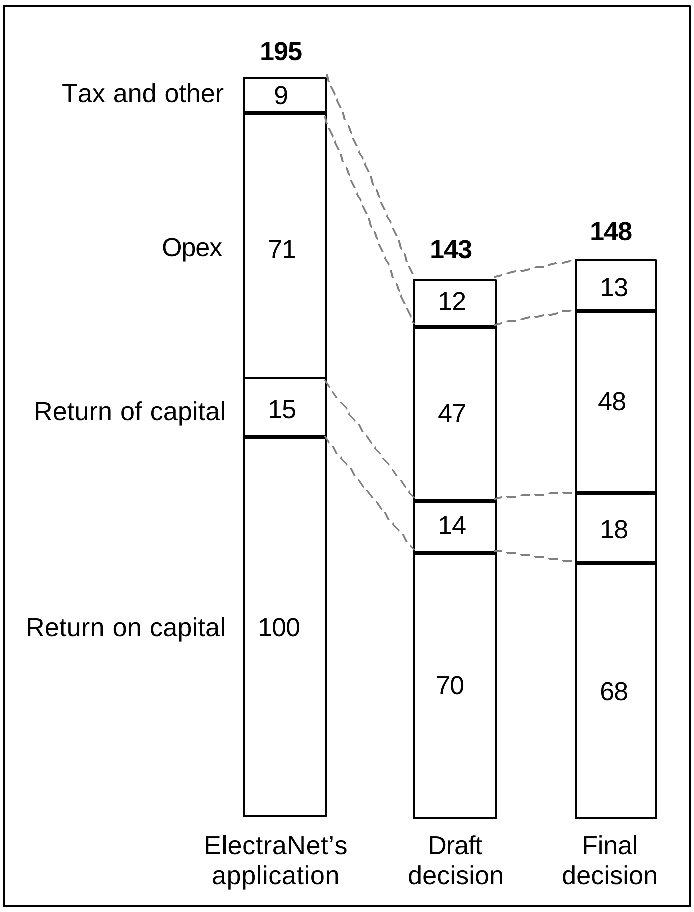
The final MAR will be determined by adding (or deducting) the service standards incentive (or penalty) amount to the above AR.

Commission staff estimate that this decision would result in a real price reduction of approximately four per cent from now to the end of the regulatory period. This reduction is mainly due to the increased electricity transported exceeding the growth in (real) revenues. The overall price decrease over the regulatory period consists of:

- an initial increase of under two per cent in the first year (mainly due to the EPO under recovery of about $5 million, this amount which actually relate to previous years is being recovered in the first year)
- subsequent reductions of about one per cent per annum on average during the rest of the period.

The figure 7.1 shows a rough comparison of ElectraNet's revenue cap for its first full year (2003-04), with the Commission's decision for the first six months of 2003, prorated for 2002-02. The diagram is for illustrative purposes only.

Figure 7.1 Comparison of the ARs (illustrative) ($m)



Return on capital reduction due to:

- changes in WACC parameters (table 3.6)
- changes to opening RAB (not accepting adjustments regarding easements and interest during construction) and capex (net reduction in proposed capex-chapter 5)

Opex, as indicated in the above figure, includes grid support ($4 million in the draft and final decisions). The reduction to Opex proposed in the draft decision is mainly due to:

- treatment of refurbishment expenses as capex (resulting in a reduction of about $11 million per annum)
- benchmarking against historical figures (about $13 million per annum).

The small increase in opex between that proposed in the draft and final decisions is mainly due to equity and debt raising costs.

The category 'tax and other' includes ElectraNet's under recovery from the EPO, which the Commission has allowed.

8 Service standards

8.1 Introduction

TNSPs provide a service and receive revenues not exceeding the AR determined by the Commission. Such service differs from state to state, usually explained by differing asset structures, topography, etc.

Under existing arrangements TNSPs do not have any incentive to improve service quality. In contrast, they have an incentive to minimise costs, as it would result in increased profits. By doing so the quality of service may decline, imposing much larger costs on other market participants.

Therefore TNSPs should be given an incentive to improve the quality of service. Likewise they should be penalised for reducing the quality of service.

The Commission intends to implement an incentive scheme to provide appropriate incentives for a TNSP to maintain or improve service quality. This scheme will provide an incentive (or penalty) in addition to the AR that a TNSP can earn.

The Commission engaged SKM to develop a service standard guideline. This decision is based on SKM's report and recommendations.

8.2 Code requirements

Clause 6.2.4(c)(2) of the code states that when the Commission sets a revenue cap it must have regard to:

- the service standards referred to in the code that apply to the regulated transmission network
- any other standards imposed on the network by agreement with the relevant network users.

Clause 5.2.3(b) states that a network must comply with the service standards specified either in schedule 5.1 or in a connection agreement. However if a connection agreement adversely affects a third network user, then schedule 5 would supersede it.

Schedule 5.1 outlines the planning, design and operating criteria that a network must achieve. The design of a network has a clear impact on its performance over time.

8.3 Performance targets and incentives

8.3.1 Introduction

The service standards proposed for ElectraNet are based on the SKM's recommendations.

The Commission engaged SKM to develop a service standards incentive scheme that will apply to all TNSPs under the NEM. SKM consulted extensively with all interested parties in developing the scheme. SKM's final report is now on the Commission's website. This scheme is consistent with the final report and recommendations.

The Commission will seek written submissions on SKM's final report and proceed to develop service standard guidelines that would apply to all TNSPs in the NEM.

Put simply, the Commission expects a TNSP to maintain the same quality of service it had delivered in the preceding three years. To measure the quality of service, the Commission selected five performance indicators. If the performance improved, the TNSP is rewarded. And if the performance deteriorates it is penalised. The maximum reward or penalty is one per cent of the TNSP's AR.

As rewards and penalties are based on changes over past performance, it is important to measure past and future performance in a consistent way (i.e. comparing like with like).

The following subsections and attachments explain the scheme, which is detailed and complex.

8.3.2 Indicators

SKM recommended the following.

1. Circuit availability
2. Loss of supply event frequency index
    - frequency of events lasting more than 0.2 system minutes
    - frequency of events lasting more than 1.0 system minute
3. Average restoration time
4. Minutes constrained (inter-regional)
5. Minutes constrained (intra-regional)

SKM and the ElectraNet jointly agreed on the definitions of these indicators to ensure consistency over time (see appendix 8.1).

8.3.3 Performance targets

SKM based performance targets on the historical data provided by ElectraNet. The yearly historical average of these indicators and targets are shown in Appendix 6 - Performance targets and incentives.

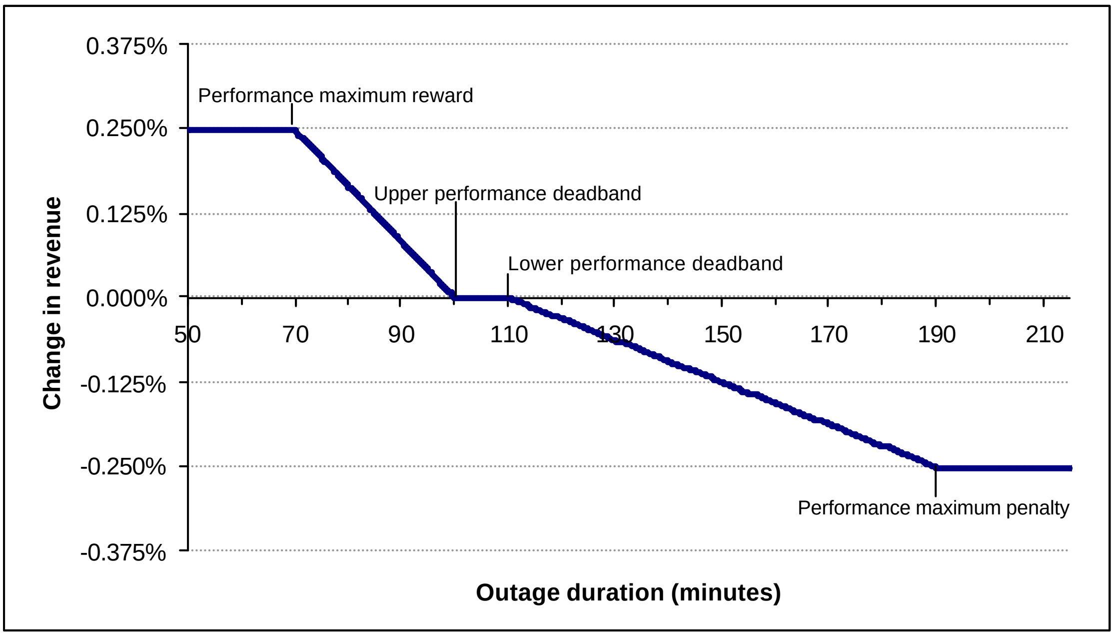
Historical information is not available for the constraints indicators (indicators 4 and 5). The Commission intends to collect this data over the first 3-5 years and then set the targets.

8.3.4 Financial incentives

The Commission considers that a one per cent increase per year in the AR would provide a large enough incentive (or penalty) for ElectraNet.

The Commission considers that the potential loss of one per cent of its AR does not materially affect ElectraNet's risk profile. The Commission chose this conservative amount taking into account the newness of the scheme. It believes that there is scope to increase the revenue at risk once enough experience has been gained about the scheme. Figure 8.1 illustrates the working of the scheme.

Figure 8.1 Change in the MAR due to average outage duration



Average outage duration during the past three years falls within the deadband from 100 to 110 minutes per annum. The deadband ensures that minor changes in performance do not result in incentive payments (or penalties).

Both penalties and incentives, for changes in outage duration, are caped at 0.25 per cent of the revenue. (The total incentives are capped at one per cent of AR.)

The slope of the graph in the top half is greater than in the bottom half. This indicates that incentives for improvement in performance are greater than penalties for deterioration. This recognises the fact that as TNSPs are generally achieving very low rates of outage, further improvements are less likely.

The amount of the reward can be calculated using appendix 3.

8.3.5 Incorporating the penalty or reward into the MAR

The Commission requires each TNSP to report annually on its service standards indicators. Accordingly ElectraNet must report the actual performance for the indicators defined in Appendix 7 - Equations linking performance and penalty/reward

In its draft decision the Commission proposed that the penalty or rewards will lag performance by one year. However ElectraNet noted that the code requires TNSPs to publish transmission prices before the beginning of the regulatory year. Therefore the Commission has incorporated ElectraNet's suggestion to measure performance in the calendar year and include the financial incentives in the regulatory year. That is, the MAR in regulatory year two will include the penalty/reward for the performance achieved in calendar year one.

Table 8.1 Timing of financial incentives

Allowed revenue [1] (Financial year) (t)	Financial incentive [2] (Calender year) (ct)
1 January - 30 June 2003	-
1 July 2003 - 30 June 2004	1 January 2002 - 31 December 2002
1 July 2004 - 30 June 2005	1 January 2003 - 31 December 2003
1 July 2005 - 30 June 2006	1 January 2004 - 31 December 2004
1 July 2006 - 30 June 2007	1 January 2005 - 31 December 2005
1 July 2007 - 30 June 2008	1 January 2006 - 31 December 2006

1. The allowed revenue for regulatory period t is based on the financial year listed
2. The financial incentive for regulatory period t is based the calender year listed

The MAR is calculated as follows:

$$\mathrm{MAR}_t = (\text{allowed revenue}) + (\text{financial incentive})$$

$$= \left(\mathrm{AR}_t\right) + \left(\frac{(\mathrm{AR}_{t-1} + \mathrm{A}R_{t\text{-}2})}{2} \times S_{ct}\right)$$

Where:

MAR = maximum allowed revenue

AR = allowed revenue

S = service standards factor

t = regulatory period in (see table 8.1)

ct = calender year (see table 8.1)

This calculation does not allow the effect of 'S' to be compounded into future periods. That is each annual service standards reward or penalty will only affect revenues in one year. Further, the calculation of the financial incentive matches the allowed revenue for the period in which performance is measured. That is, the revenue for the calendar year in which service standards are measured is the time weighted average of the relevant AR for the overlapping regulatory year.

Appendix 7 - Equations linking performance and penalty/reward shows how to calculate 'S'.

8.4 ElectraNet's application

ElectraNet did not propose specific performance targets. However its application outlined its views on transmission service standards.

ElectraNet noted that the Commission must consider the service standards in the code and in connection agreements when deciding revenue caps. It considers that any level of service higher than required by the regulatory compact deserves additional revenues.

8.4.1 Principles of performance standards and targets proposed by ElectraNet

ElectraNet proposed that network performance standards must:

- be reasonable and appropriate for each regulated TNSP
- apply only to performance that is controllable by TNSPs
- be consistent with network planning, development and operating standards
- recognise the importance of NEMMCO's role in power system security
- recognise that changing service standards require changing revenue
- recognise that the possibility of changing revenue increases the risk for TNSPs.

Though the application did not include specific targets it recognised that:

- TNSPs should deliver the performance targets over the long term
- setting performance targets requires long-term historical performance data
- care must be taken in interpreting historical data.

ElectraNet supports the careful use of output measures as reliability indicators in establishing and monitoring performance trends. Unsatisfactory trends should be analysed to discover the cause.

8.4.2 Financial incentives for network performance

ElectraNet believes that linking TNSP performance to its revenues should be done on an annual basis, with a low risk-reward framework and target short-medium term performance measures.

ElectraNet must also meet standards imposed by the South Australian transmission code, including exit point reliability standards and global output measures. ElectraNet remains committed to set performance standards for interconnectors and suggested the following indicators:

- connection point interruptions, both frequency and duration
- number of loss of supply events, greater than 0.2 and one, system minutes
- unplanned transmission circuit outage frequency
- interconnector available capacity factor.

8.5 Submissions by interested parties

EAG, ECCSA, NRG, Origin and TransGrid provided submissions on service standards.

TransGrid supports the Commission's service standards review and believes the Commission is the best placed regulator to administer the incentive scheme.

EAG noted that ElectraNet's application did not included specific performance data. It concluded that the Commission could not develop an incentive scheme without such data.

Origin Energy considers that the CPI-X framework provides the TNSP with an incentive to minimise costs and not to take account of the energy market more generally. Origin believes it is important to link the TNSPs revenue, decided in the regulatory decision, to its performance.

NRG supports linking ElectraNet's regulated revenue to its performance. It notes that TNSPs should be held accountable for performance under their control or where they are best placed to manage the risks. For example no one can control lightning strikes, however, the TNSP can ensure the network is protected (to the extent possible) to limit the impact of lightning.

NRG also considered increasing the firmness of the settlement residues by linking the TNSPs income to the residues.

ECCSA supports the Commission's service standards review. It considers that ElectraNet must pay a penalty if it cannot meet the standards prescribed in the code or the South Australian transmission code.

ECCSA further notes ElectraNet did not mention performance benchmarks in terms of its investing activities. ElectraNet must demonstrate that capex and opex allowances are spent wisely and sensibly.

8.6 Submissions in response to the draft decision

8.6.1 Submissions made by TNSPs

ElectraNet noted that it had provided SKM with additional historical data that was not accounted for in the draft decision. It believes that the Commission should account for this data in its final decision.

ElectraNet and TransGrid:

- were concerned that the incentive scheme could result in TNSPs being penalised when outages occur due to capital works undertaken to improve network reliability
- argued that TNSPs should be rewarded for operating at or near best practice
- noted that improvements in practice are difficult to achieve making it harder for the TNSP to receive benefits.

ElectraNet observed that the Commission's proposal for a one-year lag between performance and incentive payments would actually result in a two-year lag, because of a code requirement regarding publishing transmission prices. ElectraNet proposed a one-and-a-half year lag instead.

8.6.2 Submissions made by consumers

NRG, ECCSA and EUAA believed that introducing performance incentives on TNSPs is a step in the right direction. Performance incentives increase transparency and accountability, and are vital to the success of the NEM.

NRG stated that 1 per cent revenue at risk is not material and that the percentage should be increased by one or two points. This would be consistent with ESCoSA's intended plan for DNSPs in South Australia.

NRG accepts the use of performance measures regarding circuit availability, supply interruptions and outage duration. But is concerned that there may not be enough information on constraints to implement intra and inter regional constraint measures.

NRG and the ECCSA believe that additional measures should be designed to target interconnections. The ECCSA believes such performance measures would ensure firm supply.

NRG believes that the TNSPs are best placed to manage some risks they have no control over. This includes events such as foreseeable weather-related events and also generator failure.

NRG encourages the introduction of market impact performance measures. Further NRG Flinders suggests that market-based revenue should replace regulated revenue where possible.

The EUAA believes the proposed incentive scheme does not provide strong enough incentives. It believes that outcomes similar to the UK model should be achieved instead.

8.7 Commission's considerations

8.7.1 Perverse incentives

ElectraNet and TransGrid noted that capital work requires outages for which ElectraNet might be penalised. The Commission considers that ElectraNet must decide how to operate its network when undertaking capital works. The Commission expects that financial incentives for minimised outages and maximised availability should influence ElectraNet's decisions.

The Commission believes the performance targets have been set leniently to account for the newness of the incentive scheme. The performance targets will be reviewed when the Commission has had the chance to monitor ElectraNet's service levels over time.

8.7.2 Maintaining performance levels

ElectraNet and TransGrid noted that once ElectraNet achieves best practice, performance improvements are near impossible to achieve. This has been recognised by designing the scheme in such a way that performance improvements earn rewards more rapidly than performance deteriorations accrue penalties.

8.7.3 Market impact incentives

The consumers' submissions argued that market impact measures would provide better incentives for the TNSPs. The Commission accepts this. However it was impossible to include market impact measures due to unavailability of data and difficulties in establishing a causal connection between outage and TNSP actions.

The Commission will explore implementing market measures when the current scheme comes up for review.

8.7.4 Conclusion

After considering all of the above the Commission has decided to maintain the same scheme, the details of which are at section 8.3. It updated the targets for ElectraNet using the latest information provided by SKM.

9 Financial indicators

9.1 Introduction

Under clause 6.2.4(c) of the code the Commission must consider the relevant financial indicators in setting a revenue cap. Accordingly, it has examined the impact of this decision on ElectraNet's ability to manage its financial position. The Commission also has used this analysis to provide a reasonableness check of the AR. This approach is consistent with that outlined in the Commission's DRP, the NSW and ACT, and Queensland revenue cap decisions.

Financial indicator analysis is relevant in that investors, financiers and credit rating agencies use it when assessing a firm's credit-worthiness. However the Commission cautions on placing too much emphasis on financial indicators of regulated entities as they are not strictly comparable with entities in the competitive market.

More importantly ElectraNet has a revenue stream that is inflation indexed and almost guaranteed for the next five-and-a-half years. This is unlike firms in a competitive market whose revenue stream can vary. This important difference limits the usefulness of the financial indicator analysis for TNSPs.

9.2 Financial indicator analysis

To assess the implications of the total revenue assessed for ElectraNet, the Commission has used both qualitative and quantitative indicators. The former broadly described as the business profile and the latter as the financial profile. A firm with a strong business profile but a weak financial profile may achieve the same credit rating as a firm with a weak business profile but strong financial profile.

9.2.1 Business profile

A range of issues affect the assessment of a firm's business profile, including:

- the nature of the markets in which the firm operates
- the competitiveness of the firm
- the cost management systems of the firm
- the quality of key personnel of the firm.

It is not the Commission's role to comment on these factors. However the Commission considers that under the current revenue cap regime, TNSPs should be able to maintain a relatively strong business profile.

9.2.2 Financial profile

There are significant differences between the principles underlying the Commission's regulatory financial model and the models used to construct standard financial statements. However a high-level assessment could lead to reasonable conclusions.

The Commission has used a typical range of financial ratios measuring ElectraNet's profitability, gearing, and its ability to cover operating costs, service debts and finance new expenditure. These are shown in table 9.2.

9.2.3 Credit rating

To generate an indicative overall credit rating from the business profile and financial ratios, the Commission has applied the classifications normally used by S&P. Those ratings, and the way they are normally interpreted, are shown in table 9.1.

Table 9.1 Standard and Poor's key indicators

Utility business profile	Funds flow interest Cover (times)				Funds flow net debt payback (years)				Internal financing ratio (per cent)			
	AAA	AA	A	BBB	AAA	AA	A	BBB	AAA	AA	A	BBB
Excellent	4.00	3.25	2.75	1.50	4.0	6.0	9.0	12.0	100	70	60	40
Above ave.	4.25	3.50	3.00	2.00	3.5	5.0	7.0	9.0	100	80	70	50
Average	5.00	4.00	3.25	2.50	3.0	4.0	5.5	7.0	100	100	90	55
Below ave.	X	4.25	3.50	3.00	X	4.0	5.5	7.0	X	100	100	75
Vulnerable	X	X	4.00	3.50	X	X	4.0	6.0	X	X	100+	90

AAA Extremely strong capacity to meet financial commitments.
AA Very strong capacity to meet financial commitments.
A Strong capacity to meet financial commitments but somewhat susceptible to adverse economic conditions and changes in circumstances.
BBB Adequate capacity to meet financial commitments but more susceptible to adverse economic conditions however is not considered vulnerable.
Ratings in the BB, B, CCC, CC and C categories are regarded as having significant speculative business, financial and economic conditions.

9.3 Submissions by ElectraNet

ElectraNet regards any rating lower than BBB+ to be unacceptable. ElectraNet claims that an AR lower than it asked for in the application would adversely affect both its ability to fund required investments and financial viability.

In response to the draft decision ElectraNet argues that the Commission should adopt a dividend payout ratio of 86 per cent in its analysis, to reflect the actual circumstances of the business.

9.4 Commission's assessment

The Commission calculated a set of financial indicators, using AR and the costs determined in this decision (see table 9.2). It considers that ElectraNet's business profile lies between excellent and above average, given the likely stability of its earnings and the lack of competitors for its services. Considering both the financial and business profiles, ElectraNet is likely to have an overall credit rating that trends from AA to BBB over the regulatory period.

In calculating the financial indicators, the Commission used a benchmark gearing ratio of 60 per cent for ElectraNet. The Commission notes ElectraNet's actual gearing is about 80 per cent. However, as a matter of policy, the Commission uses a benchmark gearing ratio rather than the actual gearing of an individual business. It is also consistent with:

- the calculation of the WACC
- the treatment across all entities regulated by the Commission
- previous decisions made by the Commission.

In calculating the financial indicators, the Commission usually estimates the dividend payout ratio based on historical figures. Based on ElectraNet's and its predecessors' history the average ratio is about 86 per cent. However, since ElectraNet acquired the business in October 2000 the situation has changed materially making historical comparisons less useful. For example, ElectraNet paid no dividends in 2000-01.

The Commission notes that dividend policy is a matter for individual businesses. A dividend payout is usually a residual decision, which solely rests with the company. For example, S&P has stated that:

> Common dividend policy also has a direct bearing on liquidity and financing flexibility to the extent that sufficient cash is retained to reinvest in the business. High dividend payout ratios are viewed poorly, particular if a utility has a challenging construction program.[48]

However for the purpose of calculating ElectraNet's financial indicators, the Commission considers it would be appropriate to assume a benchmark dividend payout ratio of 50 per cent, like it did in the draft decision.

In October 2002 S&P stated that:

> The recent ACCC draft regulatory determinations for ElectraNet Pty Ltd and SPI PowerNet Ltd did not result in any rating action. Standard & Poor's believes that both companies can manage their operations within the terms of the draft determinations and retain their current ratings. The final determinations, due later this year are not expected to result in lowering of the revenue cap.[49]

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[48] Standard and Poor's, *Energy Australia & New Zealand*, November 2001, p. 19.

[49] Standard and Poor's, *Australian Report Card-Utilities*, 29 October 2002, p. 2.

The Commission notes that the AR in this final decision is higher than that in the draft decision. ElectraNet is therefore likely to retain its current credit rating.

Table 9.2 ElectraNet financial indicators

Financial Indicators	2003-04	2004-05	2005-06	2006-07	2007-08
EBIT to revenues (%)	57.80	60.90	62.94	65.61	62.31
EBITD to revenues (%)	71.54	75.98	78.23	82.26	76.17
EBIT to funds employed (%)	10.41	10.63	10.65	10.92	10.43
EBIT to regulated assets (%)	10.41	10.63	10.65	10.92	10.43
Pre-tax interest cover (times)	2.71	2.77	2.78	2.85	2.72
Funds flow net interest cover (times)	3.36	3.46	3.45	3.57	3.32
S&P rating (excellent business profile)	**AA**	**AA**	**AA**	**AA**	**AA**
S&P rating (above average business profile)	**A**	**A**	**A**	**AA**	**A**
Funds flow net debt pay back (years)	8.62	8.26	8.29	7.89	8.79
S&P rating (excellent business profile)	**A**	**A**	**A**	**A**	**A**
S&P rating (above average business profile)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
Internal financing ratio (%)	59.90	52.38	62.34	79.80	109.77
S&P rating (excellent business profile)	**BBB**	**BBB**	**BBB**	**BBB**	**BBB**
S&P rating (above average business profile)	**BBB**	**BBB**	**BBB**	**A**	**AAA**
Gearing	60.00	60.00	60.00	60.00	60.00
Payout ratio	50.00	50.00	50.00	50.00	50.00

Note: Financial indicators formulae:

EBIT/funds employed	EBIT/(debt + equity)
Dividend payout ratio	Dividends/NPAT
Funds flow interest cover	(NPAT + depreciation + interest + tax)/interest
Funds flow net debt pay back	(Debt - (investments + cash))/(NPAT + depreciation)
Internal financing ratio	(NPAT + depreciation - dividends)/capex
Pre-tax interest cover	EBIT/interest
Gearing	Debt/(debt + equity)

9.5 Conclusion

The Commission considers that AR in this decision would not adversely affect either the ongoing financial viability or the ability to access capital markets of ElectraNet.

Attachment A - Submissions in response to application

In response to the Commission's call for submissions on ElectraNet's application and the consultants reports, submissions were received from:

AGL

Conservation Council of South Australia

Electricity Consumers Coalition of South Australia

Energy Action Group

NRG Flinders

Origin Energy

Powerlink

SA Water

Transend

TransGrid

TXU

WMC Copper Uranium

Attachment B - Submissions in response to the draft decision

In response to the Commission's call for submissions on the draft decision, submissions were received from:

ElectraNet

Electricity Consumers Coalition of South Australia

Energy Action Group

Energy Users Association of Australia

Hydro Tasmania

NRG Flinders

Powerlink

SPI PowerNet

Transend

TransGrid

Appendix 1 - Scenarios and their assessed probabilities

Possible outcome	Notes	Probability
Additional Generation in the South of South Australia		
Low levels of additional generation	Only committed generation added (no wind generation).	20%
Medium levels of additional generation	340MW of additional generation (including wind)	40%
High levels of additional generation		40%
Additional Generation in the North and West of South Australia		
Low levels of additional generation	Only committed generation added (no wind generation).	80%
High levels of additional generation	490 MW of additional generation (including wind).	20%
Electricity Demand Growth		
Low demand growth	As in NEMMCO's 2001 Statement of opportunities.	20%
Medium demand growth	As in NEMMCO's 2001 Statement of opportunities.	80%
South Australian Magnesium Project (SAMAG Project)		
Proceeds	230 MW generation and between 20 MW and 170 MW load.	50%
Does not proceed		50%

Appendix 2 - ElectraNet's proposed capital projects (> $10 million)

Project Number	Project Name	Project Est. Total Cost ($m)	Probability. Prior to June 2008	Proposed Roll-in ($m)	Stated Reason	Proposed to commence
Section 1 - Network Augmentation						
1.1	Bungama/Brinkworth 275/132 kV (No SAMAG)	24.7	0.50	12.2	Required as alternative to rebuild of Playford- Bungama 132kV lines which are in very poor condition	
1.2	Playford relocation to Davenport	14.0	1.00	14.0	Required due to age and condition of existing Playford switchyard	July - Dec 2002
1.3	South East to Snuggery 132 kV Line	10.2	1.00	10.2	Required to maintain adequate voltage levels during first level contingency	2004-05
1.4	Uprate all ElectraNet lines designed for 49^{o}C operation	18.4	1.00	18.4	Required to release additional capacity in various lines in order to supply load growth.	2004-05
1.6	Eastern Hills Project	12.1	1.00	11.9	Required to prevent overloading of lines during first level contingency	2004-05
1.13	East Terrace - Magill 2nd 275 kV cable, plus East Terrace 2nd 275/66 kV transformer	45.3	0.80	34.8	Required to supply load increases on the east terrace supply point to Adelaide CBD	2004-05
1.21b	Southern reinforcement, Wilunga - Network part	17.7	0.67	11.8	Required to supply load increases in the area	2005-06
1.24	Establish Tungkillo 275 kV substation - Stage 1	11.0	0.40	4.4	Required to maintain network reliability to southern suburbs	2005-06
1.33	Eyre Peninsula 132 kV Reinforcement	67.5	0.33	22.1	Required to facilitate connection of wind generation. ElectraNet expect it to pass part (b) of ACCC's regulatory test	2004-05
1.36	Monash 275/132kV substation and Robertstown - Monash 275 kV transmission line	44.7	0.80	35.8	Required to maintain adequate voltage levels during first level contingency	July - Dec 2002
1.38	Heywood Augmentation	32.9	0.64	21.1	To facilitate connection of wind generation and to increase the capacity of the Victorian interconnection at Heywood to 650MW	2004-05
1.44	South East to Tungkillo 275 kV circuit	101.4	0.13	13.0	To facilitate the connection of wind powered generation	2006-07

Project Number	Project Name	Project Est. Total Cost ($m)	Probability. Prior to June 2008	Proposed Roll-in ($m)	Stated Reason	Proposed to commence
1.52	Victorian Border - Monash component of SNI	30.9	0.45	13.8	To provide additional interconnection capacity between SA and NSW	2003-04
1.55	Bungama/Brinkworth 275/132 kV (with SAMAG)	28.5	0.50	14.0	Required as alternative to rebuild of Playford - Bungama 132 kV lines which are in very poor condition (Note that this is a mutually exclusive alternative to project 1.1	July - Dec 2002
Section 7 - ETSA Utilities - post EPO						
7.8	Northfield third 225 MVA 275/66kV transformer	11.6	0.80	8.6	To increase capacity at the Northfield ETSA Utilities supply point in response to load growth in the area.	2006-07

Notes: A number of projects are included in ElectraNet's capex forecast with multiple roll-in dates with varying probabilities. In these cases, commencement dates are indicative only.

Appendix 3 - Meritec review of selected projects

Bungama/Brinkworth 275kV Project (Project Report No.s 1.1 and 1.55)

Meritec notes that these two mutually exclusive projects of similar value have been included for augmentation of the Bungama/Brinkworth network each with a 50 per cent probability of proceeding within the regulatory period. In notes that only one of the two projects will be required during the regulatory period, depending on whether the SAMAG project proceeds. Project 1.1 has an estimated cost of $24.7 million and Project 1.55 $28.5 million.

Meritec notes that these projects are driven by the age and condition of the Playford-Bungama 132 kV lines. It states that these lines are in the worst condition of any in ElectraNet's system and that ElectraNet has determined that rebuilding these lines would be more expensive than the option proposed and would result in voltage collapse during an outage of the Hummocks to Waterloo line.

If the SAMAG project does not proceed, the project consists of the installation of one 275/132 kV, 160 MVA transformer at Bungama substation, and replacement of the existing 275/132 kV, 60 MVA transformer at Brinkworth with a 160 MVA unit. At the same time an existing 275 kV line would be turned into Bungama and the redundant sections of the 132 kV line between Playford and Bungama removed. However, if the SAMAG project was to proceed, then 3 x 275/132 kV, 160 MVA transformers would be required at Bungama and the Brinkworth transformer would not be uprated.

ElectraNet proposes to commence either of the projects in the second half of 2002, for completion and roll-in during 2003-04. Meritec believes that this project is appropriate.

Playford-Davenport 132 kV Substation Supply Consolidation (Project No. 1.2)

This project has an estimated cost of $14 million with a probability of 1.0 (i.e. certain) of occurring within the regulatory period. Meritec notes that this project is driven by the deteriorating condition of the Playford switchyard as well as the need to exit the site, which is part of the disused Playford A power station. It also notes that it would allow consolidation of activities at the nearby Davenport substation.

The project involves rebuilding the Playford 132 kV switchyard at the Davenport substation and installing new 275/132 kV, 160 MVA tie transformers at Davenport. The 132/33 kV transformers servicing ETSA Utilities would also be moved.

ElectraNet proposes to commence this project in the second half of 2002, for completion and roll-in during 2003-04. Meritec believes that this project is appropriate.

Appendix 4 - capex to facilitate distributed generation

Project	Estimated total project cost ($m)	Probability of proceeding before June 2008	Proposed construction date
Eyre Peninsula	67.5	0.33	July 02-2007/08
South East 3rd 275kV line to Tungkilla	101.4	0.13	2006/07-2007/08
Split Cult-Davenport	8.0	0.12	2006/07-2007/08
Mintaro Brinkworth 132kV uprate protection[1]	0.01	0.16	2007-08
Mintaro Waterloo 132kV uprate protection[1]	0.01	0.16	2007-08
Black Range	8.0	0.40	2006-07

Source: Meritec capex report page 26.

1. Appeared in ElectraNet's application as opex.

Appendix 5 - Performance indicator definitions

Measure 1 Transmission circuit availability

Sub-measures	Transmission circuit availability (critical circuits) Transmission circuit availability (non-critical circuits) Transmission circuit availability (peak periods) Transmission circuit availability (intermediate periods) Transmission lines Transmission transformers Transmission reactive
Unit of Measure	Percentage of total possible hours available.
Source of Data	TNSP outage reports and system for circuit availability Agreed Schedule of Critical Circuits and plant Nominated peak/off-peak hours Currently peak-7:00 am to 10:00 pm weekdays Or as otherwise defined by the TNSP/NEMMCO Off peak-all other times May include intermediate time periods and seasonal periods
Definition/Formula	Formula: $$\frac{\textbf{No. hours per annum defined (critical/non-critical) circuits are available}}{\textbf{Total possible no. of defined circuit hours}} \times 100$$ Definition: The actual circuit hours available for defined (critical/non-critical) transmission circuits divided by the total possible defined circuit hours available. Note that there shall be an annual review of the nominated list of critical circuits/system components
Exclusions	Exclude unregulated transmission assets (e.g. same connection assets). Exclude from ‘circuit unavailability’ any outages shown to be caused by a fault or other event on a ‘3rd party system’ e.g. intertrip signal, generator outage, customer installation (TNSP to provide list) Force majeure events
Inclusions	‘Circuits’ includes overhead lines, underground cables, power transformers, phase shifting transformers, static var compensators, capacitor banks, and any other primary transmission equipment essential for the successful operation of the transmission system (TNSP to provide lists) Circuit ‘unavailability’ to include outages from all causes including planned, forced and emergency events, including extreme events

Measure 2 Loss of supply event frequency index

Unit of Measure	Number of significant events per annum
Source of Data	TNSP outage reports and system for circuit availability
Definition/Formula	Number of events greater than 0.2 system minutes per annum Number of events greater than 1.0 system minutes per annum Such that: ▪ a 0.2 system minute event has a return period of one year ▪ a 1.0 system minute event has a return period of two years
Exclusions	Exclude unregulated transmission assets (e.g. some connection assets) Exclude any outages shown to be caused by a fault or other event on a 'third party system' e.g. intertrip signal, generator outage, customer installation Planned outages Force Majeure events
Inclusions	All unplanned outages exceeding the specified impact (i.e. 0.2 minutes and 1.0 minutes) Includes outages on all parts of the regulated transmission system Includes extreme events

Measure 3 Average outage duration

Sub-measures	Transmission lines Transmission transformers/plant
Unit of Measure	Minutes
Source of Data	TNSP Outage Reporting System
Definition/Formula	Formula: $$\frac{\textbf{Aggregate minutes duration of all unplanned outages}}{\textbf{No. of events}}$$ Definition: The cumulative summation of the outage duration time for the period, divided by the number of outage events during the period
Exclusions	Planned outages Excludes momentary interruptions (< one minute) Force majeure events
Inclusions	Includes faults on all parts of the transmission system (connection assets, interconnected system assets) Includes all forced and fault outages whether or not loss of supply occurs

Measure 4 Transmission constraints (Intra-regional)

Unit of Measure	Hours per annum
Source of Data	NEMMCO and TNSP
Definition/Formula	Formula: Aggregate number of hours per annum that binding constraints exist on any part of the interconnected transmission system within a region (excludes interconnectors)
Exclusions	Hours of binding constraints at or near (>95 per cent) the capacity determined by the constraint equation describing all transmission elements in service Excludes connection assets Hours of binding constraints where non-credible generation contingencies coincide with previously notified planned outages Force majeure events
Inclusions	Includes binding constraints requiring 'out-of-merit-order' scheduling of generation or rotational load shedding Includes binding constraints from all causes including planned, forced and emergency events, including extreme events

Measure 5 Transmission constraints (Inter-regional)

Unit of Measure	Hours per annum
Source of Data	NEMMCO and TNSP
Definition/Formula	Formula: Aggregate number of hours per annum that binding constraints exist on an inter-regional interconnector. Hours of binding constraints to be accumulated against 'importing' TNSP.
Exclusions	Hours of binding constraints at or near (>95 per cent) the capacity determined by the constraint equation describing all transmission elements in service Hours of binding constraints where non-credible generation contingencies coincide with previously notified planned outages Any event which was clearly as a consequence of action or inaction of another TNSP Force majeure events
Inclusions	Events where binding constraints occur due to unavailability of interconnector support assets Includes binding constraints from all causes including planned, forced and emergency events, including extreme events

Definition of force majeure

For the purpose of applying the Service Standards Performance Incentive Scheme to ElectraNet, 'Force majeure events' means any event, act or circumstance or combination of events, acts and circumstances which (despite the observance of good electricity industry practice) is beyond the reasonable control of the party affected by any such event, which may include, without limitation, the following:

- fire, lightning, explosion, flood, earthquake, storm, cyclone, action of the elements, riots, civil commotion, malicious damage, natural disaster, sabotage, act of a public enemy, act of God, war (declared or undeclared), blockage, revolution, radioactive contamination, toxic or dangerous chemical contamination or force of nature

- action or inaction by a court, government agency (including denial, refusal or failure to grant any authorisation, despite timely best endeavour to obtain same)

- strikes, lockouts, industrial and/or labour disputes and/or difficulties, work bans, blockades or picketing

- acts or omissions (other than a failure to pay money) of a party other than the TNSP which party either is connected to or uses the high voltage grid or is directly connected to or uses a system for the supply of electricity which in turn is connected to the high voltage grid

- where those acts or omissions affect the ability of the TNSP to perform its obligations under the service standard by virtue of that direct or indirect connection to or use of the high voltage grid.

Force majeure, in this occurrence, excludes third party and natural events for which the TNSP can not reasonably be expected to cater for.

Appendix 6 - Performance targets and incentives

Indicator	Historical Performance 1996-97	1997-98	1998-99	1999-00	2000-01	2001-02	Performance for maximum penalty	Lower performance deadband	Performance target	Upper performance deadband	Performance for maximum reward	Weighting Factor	Maximum decrease in MAR (%)	Maximum increase in MAR (%)
Total circuit availability (%)	99.23	99.25	98.82	99.29	99.32	99.3	98.92	99.60	99.60	99.60	99.85	0.35	-0.35%	0.35%
Loss of Supply Event Frequency Index														
Number of events >0.2 system minutes	5	5	3	9	5	5	10	6	5	4	0	0.10	-0.10%	0.10%
Number of events >1.0 system minutes	3	2	0	2	1	1	5	2	2	2	0	0.30	-0.30%	0.30%
Average outage duration (mins)	239.1	205.7	82.7	70.9	141.3	108.6	211.04	130.00	100.00	90.00	61.40	0.25	-0.25%	0.25%
Minutes constrained (inter-regional)	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a
Minutes constrained (intra-regional)	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a	N/a

Appendix 7 - Equations linking performance and penalty/reward

In its annual notification to the Commission of its MAR, ElectraNet will include its calculation of ‘S’. ElectraNet will use the following tables to calculate ‘S’ at the end of each regulatory year. The Commission will audit ElectraNet’s calculation and approve ‘S’, making adjustments if necessary. The total ‘S’ factor is equal to the sum of the individual ‘S’ factors for each performance target.

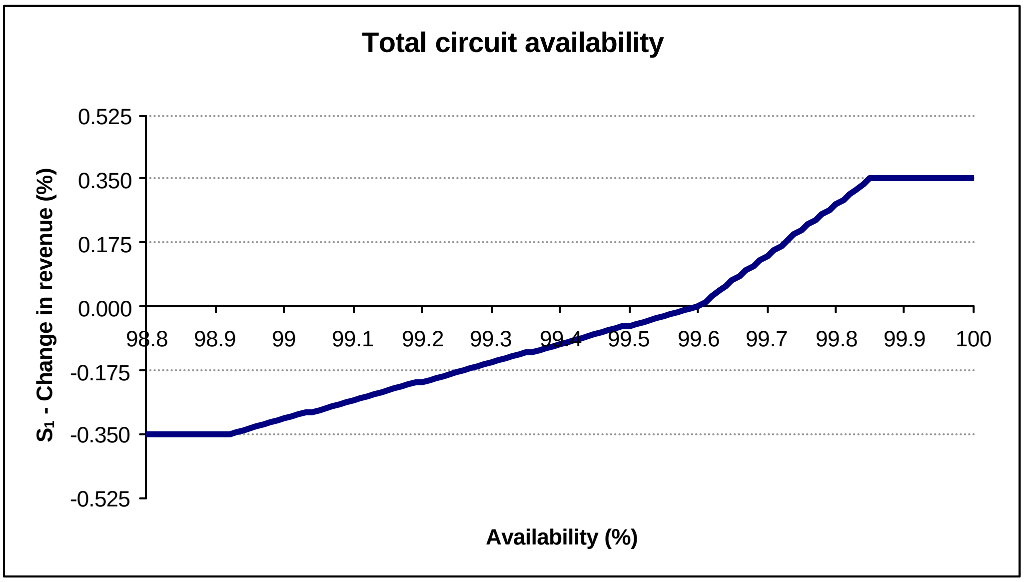
The MAR will be calculated as indicated in Chapter 8.3.5. The total ‘S’ is the sum of the individual S factors for each performance indicator, that is:

$$S = S_1 + S_2 + S_3 + S_4$$

Where the individual S factors are calculated using the following equations.

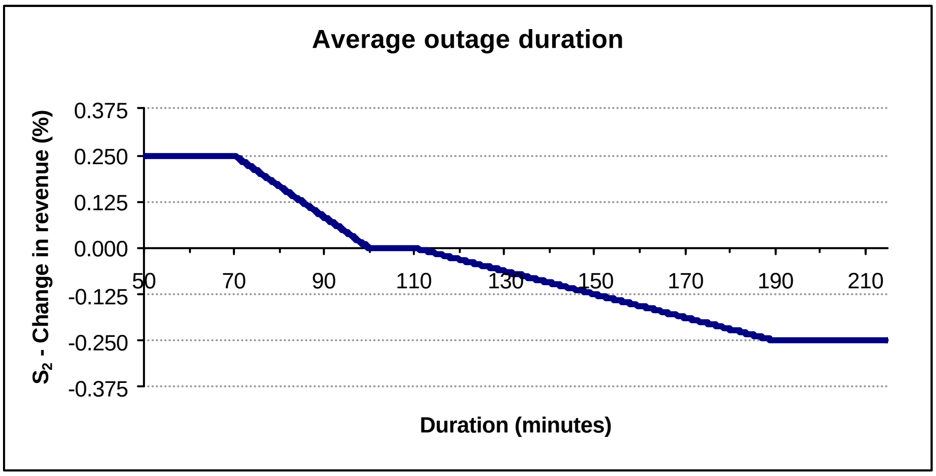
Total circuit availability (%)

							Where:			
S_1	=	-0.0035000						Actual availability	<	98.50
S_1	=	0.0046667	x	Actual availability	-	0.46317	98.50 ≤	Actual availability	≤	99.25
S_1	=	0.0000000						Actual availability	=	99.25
S_1	=	0.0100000	x	Actual availability	-	0.99250	99.25 <	Actual availability	≤	99.60
S_1	=	0.0035000					99.60 <	Actual availability		



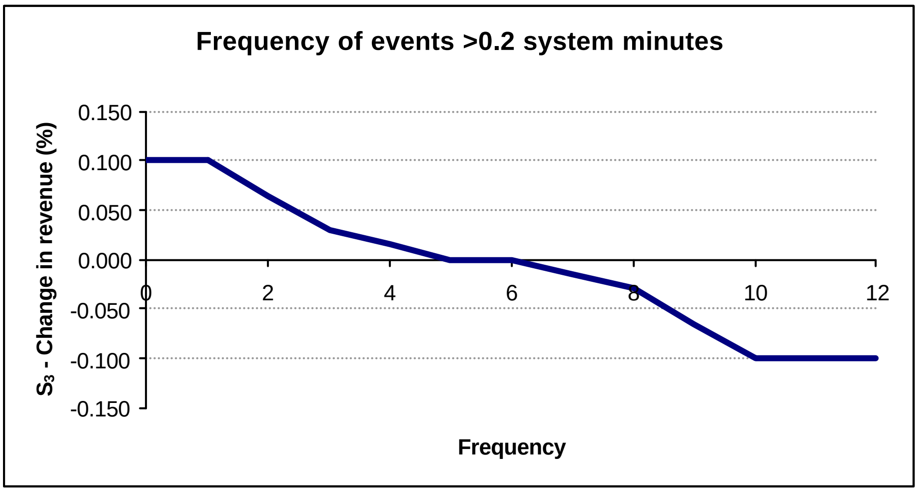
Average outage duration (mins)

					Where:			
S_2 = -0.00250000					190.00 <	Actual average outage duration		
S_2 = -0.00003125 x	Actual average outage duration	+	0.003437		110.00 <	Actual average outage duration	≤	190.00
S_2 = 0.00000000					100.00 ≤	Actual average outage duration	≤	110.00
S_2 = -0.00008333 x	Actual average outage duration	+	0.008333		70.00 ≤	Actual average outage duration	<	100.00
S_2 = 0.00250000						Actual average outage duration	<	70.00



Loss of supply event frequency index - >0.2 minutes per annum

			Where:		
S_3	=	-0.0010	Actual frequency	=	10
S_3	=	-0.0007	Actual frequency	=	9
S_3	=	-0.0003	Actual frequency	=	8
S_3	=	-0.0002	Actual frequency	=	7
S_3	=	0.0000	Actual frequency	=	6
S_3	=	0.0000	Actual frequency	=	5
S_3	=	0.0002	Actual frequency	=	4
S_3	=	0.0003	Actual frequency	=	3
S_3	=	0.0007	Actual frequency	=	2
S_3	=	0.0010	Actual frequency	=	1
S_3	=	0.0010	Actual frequency	=	0



Loss of supply event frequency index - >1.0 minutes per annum

			Where:		
S_4	=	-0.0030	Actual frequency	=	5
S_4	=	-0.0015	Actual frequency	=	4
S_4	=	-0.0005	Actual frequency	=	3
S_4	=	0.0000	Actual frequency	=	2
S_4	=	0.0008	Actual frequency	=	1
S_4	=	0.0030	Actual frequency	=	0