ETSA Utilities

ETSA Utilities' Submission re:
ESCOSA Draft 2005-10 Electricity Distribution Price Determination
Part A – Statement of Reasons

Delivering energy to South Australians

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Executive Summary

Whilst acknowledging the need to increase expenditure on the electricity distribution network, ESCOSA, in its Draft 2005 – 2010 Electricity Distribution Price Determination, proposes to reduce ETSA Utilities' revenue in the next regulatory period. Such a reduction would place extreme pressure on ETSA Utilities' ability to fund the required network investment and ultimately could place customers' reliability in jeopardy. The Draft Determination is in error by failing to comply with ESCOSA's legislative obligations and is not in the long term interests of customers or the South Australian community.

ETSA Utilities' Expenditure Submission

Since the commencement of the current regulatory period in 1999, South Australian electricity customers have received significant reductions in the distribution component of their electricity bill. These reductions will amount to more than 18% in real terms by the close of the current period in June 2005.

To a large extent, these price reductions resulted from the extraordinarily low expenditure allowances granted to ETSA Utilities over the period; less than half those of any other Australian distributor when compared on a like for like basis. Despite ETSA Utilities' commitment to maintain its position as one of the most efficient, low cost distributors in Australia, such low levels of expenditure cannot be sustained without impacting on service levels.

In our Expenditure Submission to ESCOSA, ETSA Utilities proposed significant increases to expenditure in order to upgrade and maintain the network to continue to meet growth in consumer demand, to optimise the long-term costs to consumers, and to continue to meet our community safety and environmental obligations and customers' service expectations. To support such expenditure increases, a small increase in distribution prices was proposed, less than $1/week for most residential customers. This price would still be 10% lower in real terms than the price in place when ETSA Utilities was privatised.

ESCOSA's Draft 2005 – 2010 Electricity Distribution Price Determination

In the Draft Determination, ESCOSA has acknowledged:

- The requirement to increase investment in the network; and
- ETSA Utilities' high level of efficiency in comparison with other distributors.

However, as part of the same determination, ESCOSA has proposed to reduce ETSA Utilities' revenues by an average of $10 million per annum over the next five years when compared with the previous five.

These revenue reductions have resulted largely from adjustments to a number of key parameters made by ESCOSA in the Draft Determination, namely:

- Reductions to return on equity; and
- Effective reductions to the regulatory asset base.

These adjustments have no technical or legal basis, and threaten to undermine investor confidence in the State.

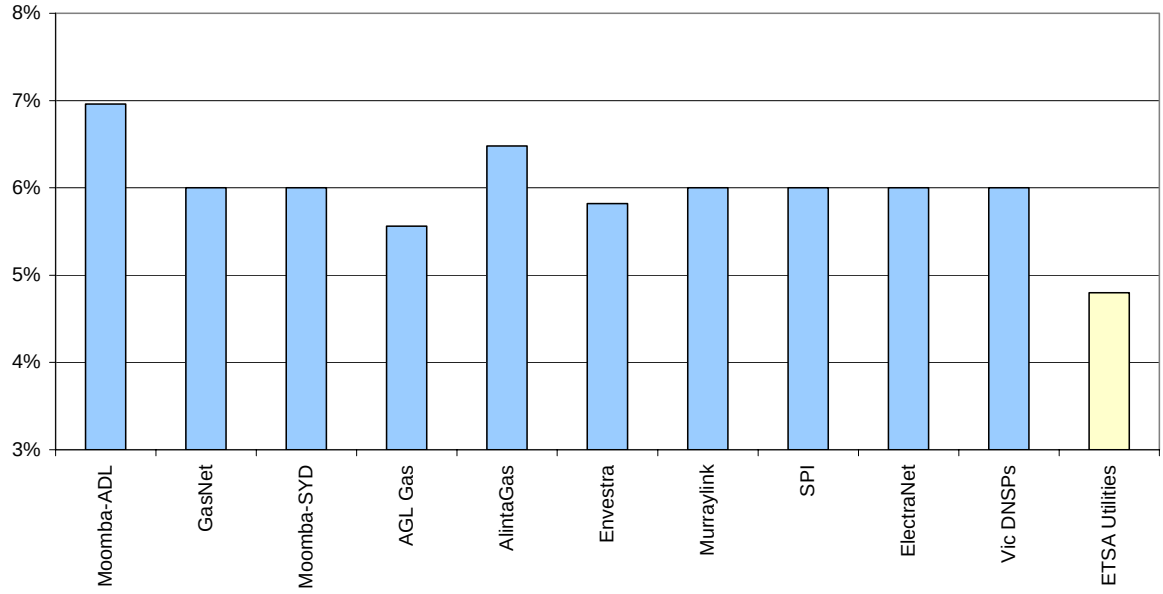
Revenue reductions driven by these factors have further been exacerbated by:

- Reductions to ETSA Utilities' proposed expenditure allowances; and
- Unrealistically high sales growth projections.

Return on equity

ESCOSA has significantly reduced ETSA Utilities' allowed return on equity such that other privatised, regulated Australian utilities, would be receiving, on average, 27% greater returns than that allowed by ESCOSA in the Draft Determination.

Figure 1. Return on equity of privatised Australian utilities[1]



This low return has largely been driven by ESCOSA's proposal to set the equity beta parameter of the weighted average cost of capital (WACC) at 0.8 when proper analysis of market evidence and determinations by other regulators would indicate a figure of at least 1.0. ESCOSA has also inappropriately considered the inter-relationships between market risk premium (MRP) and dividend imputations (gamma).

Imposing such a low return on equity would be a fundamental error by ESCOSA as it would place ETSA Utilities in a position of extreme difficulty in convincing current or future equity investors to continue to finance its substantial capital program. The correct regulatory decision by ESCOSA would require the expected return on equity investment over the life of those assets <u>not</u> to be materially different to that which could be obtained from other equity investments in a similar business.

In the Final Determination, ESCOSA must grant ETSA Utilities a return on equity consistent with a proper analysis of market evidence and consistent with the decisions of other regulators for privately owned distributors.

[1] Net of risk free rate (r_f).

Regulated asset base

ETSA Utilities' regulated asset base has effectively been reduced by $130 million by virtue of ESCOSA's decisions to:

- Alter the Building Block Formula; and
- Reduce the allowance for Working Capital.

These changes significantly undermine the jurisdictional asset base established by the South Australian Government and approved by the Australian Consumer and Competition Commission (ACCC).

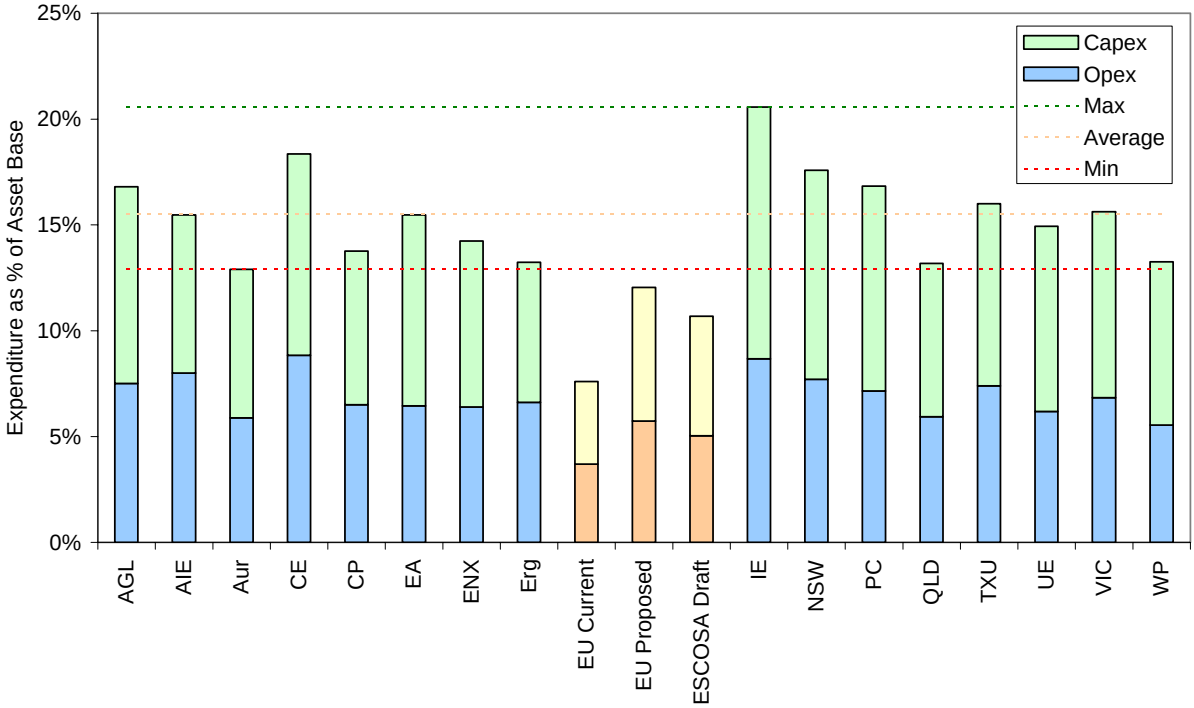
Further, ESCOSA has not complied with undertakings made to the purchasers of ETSA Utilities at the time of sale that easements would be properly valued at the time of the next price reset, in compliance with the regulatory regime.

ESCOSA must honour commitments made to ETSA Utilities' purchasers to value easements in a manner complying with the regulatory regime, and maintain investor confidence by delivering a determination that is consistent with current regulatory arrangements with respect to Working Capital and the Building Block Formula.

Expenditure allowances

ESCOSA has established expenditure benchmarks (allowances) that are set 17% lower on a like-for-like basis than the lowest allowances of any other Australian electricity distributor.

Figure 2. Capital & Operating expenditure allowances[2]



ESCOSA's proposed reductions to the Expenditure Submission are unreasonably severe and would provide ETSA Utilities with expenditure benchmarks that are inadequate to optimise long term expenditure on the distribution network.

[2] ETSA Utilities' figures show 2006 proposed expenditure. Other networks show 2005 allowances.

In particular, ESCOSA has:

- Failed to adequately consider benchmarking information in forming its views;
- Inadequately considered the drivers of costs, and particularly the impact of labour and services cost escalation; and
- Incorporated additional expenditure reductions beyond those recommended by its consultants in a review that ETSA Utilities considers was already overly aggressive in seeking cost reductions on the basis of flawed assumptions[3].

ESCOSA must reverse the inappropriate reductions made to ETSA Utilities' Expenditure Submission and provide an allowance for cost escalation consistent with reasonable economic and technical analysis.

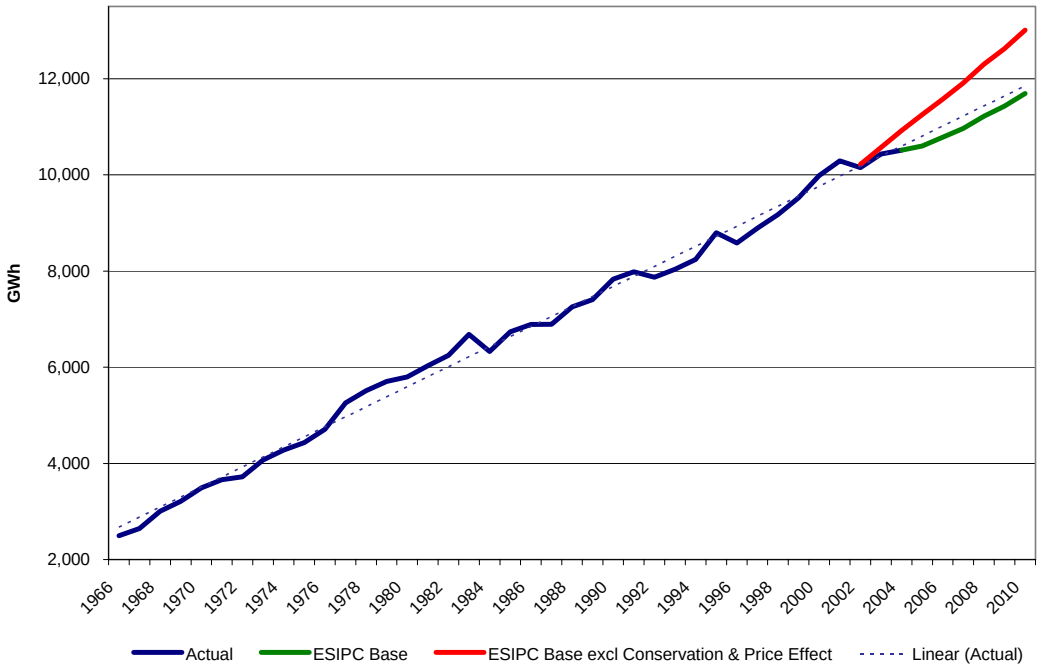
Energy Sales Forecasts

ESCOSA's Draft Determination includes sales growth forecasts averaging 1.7% over the next regulatory period. Such growth appears significantly higher than might reasonably be expected given the recent changes in consumer behaviour driven by AGL price rises and increasing energy conservation trends.

ETSA Utilities' revenues are extremely sensitive to assumptions about energy sales and appropriate sales forecasts are therefore critical to ETSA Utilities recovering allowable costs.

Growth forecasts conducted by ESIPC in September 2004 illustrated that after excluding the quantified amounts for price effects and energy conservation, the underlying growth forecast was inconsistent with historic trends.

Figure 3. Effective underlying total sales forecast[4]



[3] In their initial review, PB Associates inappropriately benchmarked ETSA Utilities on the basis of operating expenditure including transmission use of system (TUOS) fees, thereby overstating ETSA Utilities' benchmark position by a factor of two.

[4] Total sales with base price effect and conservation effect added back in.

ESCOSA has recognised that these forecasts may be too high given recent sales outcomes. The Draft Determination included a preliminary revision to the original sales forecast, and recognised that a further February 2005 sales forecast was needed to properly take account of a revised economic outlook and recent sales data.

ESIPC's re-forecast of energy sales currently being undertaken must appropriately address ETSA Utilities' concerns with the previous forecasts.

Financial impact on ETSA Utilities

ESCOSA suggest that ETSA Utilities' financial position would not be compromised by the Draft Determination however this assessment has been based on flawed and incomplete analysis. ESCOSA's detailed analysis in relation to financial ratios contains numerical errors that mask a real drop in ETSA Utilities' commercial viability relative to the current regulatory period.

Further, ESCOSA has failed to consider the impact on returns to ETSA Utilities' equity holders resulting from the determination. By virtue of:

- Reductions to return on equity;
- Changes to the building block formula; and
- Reduction to working capital;

ESCOSA's Draft Determination would reduce the value of the ETSA Utilities business by $330 million in net present value terms. It is an error to say that this would be an inconsequential financial impact.

ESCOSA must ensure that as a result of the Final Determination, ETSA Utilities' commercial viability is not negatively impacted. Such a conclusion must be based upon comprehensive financial analysis, including a consideration of the implications upon ETSA Utilities' equity investors.

Inability to finance required investment

Electricity distribution is a capital intensive business, with billions of dollars of investors' funds tied up in very long life assets.

In combination, the parameters established by ESCOSA in the Draft Determination and resultant revenue reductions would place extreme pressure on ETSA Utilities' ability to attract investors to fund the required network investment. Investors would be further deterred by ESCOSA's demonstrated willingness to change key regulatory parameters from one period to the next, thus creating a climate of regulatory uncertainty.

An inability to fund sufficient network investment will make it extremely difficult for ETSA Utilities to continue to maintain network reliability in the long-term. This is not in the long-term interests of South Australian electricity consumers. A failure, in the Final Price Determination, to ensure that the business can continue to attract investment would be a fundamental error by ESCOSA.

ETSA Utilities' EDPR Submission

In this document, ETSA Utilities further discusses the above critical issues and a range of further issues such as:

- **Allowable pass-through events:** that would ensure that ETSA Utilities and customers are not disadvantaged by treatment of uncertain events that may or may not occur during the regulatory period; and
- **ESCOSA's proposed Profit Share Scheme:** that would see ETSA Utilities receive only marginal incentives for pursuing non-regulated use of regulated assets.

ESCOSA's Final 2005 – 2010 Electricity Distribution Price Determination must address each of the issues raised in this submission in order to ensure that ESCOSA complies with its legislative obligations and deliver an outcome consistent with the long-term interests of the South Australian community.

A. Introduction

ETSA Utilities' Expenditure Submission

The 2005 Price Review presents an enormous challenge to ESCOSA. Not only is it the first electricity distribution price review that ESCOSA has undertaken, but it must be undertaken within a climate of tremendous public and political pressure to reduce electricity prices.

The public profile of electricity supply within South Australia is without parallel.

As a result of retail price rises initiated by AGL in 2002, and subsequent media and political attention, the South Australian public might reasonably perceive that they are being exploited by greedy electricity companies. This is unfortunate, as in reality it is some of the unique characteristics of the South Australian electricity market that tend to drive higher prices here than in other Australian states.

Nevertheless, distribution prices, driven by the unsustainably low expenditure allowances provided to ETSA Utilities, have reduced in real terms by nearly 18%[5] for residential customers since the commencement of the current regulatory period in 1999. ETSA Utilities has submitted that expenditure allowances must increase to allow the network to continue to meet growth in consumer demand, to optimise the long-term costs to consumers, and to continue to meet our customers' service requirements. In order to allow such expenditure increases, a small increase in distribution prices was proposed, less than $1/week for most residential customers. This price would still be 10% lower in real terms than the price in place when ETSA Utilities was privatised.

The levels of investment proposed would provide certainty that the network will be able to keep pace with projected growth in demand, particularly in rural and regional areas. As a result, the community could have confidence that customers will not have to suffer poor reliability in hot weather, or have state development constrained, by a sub-standard distribution network. We would also be able to address the issue of increasing numbers of assets reaching the end of their productive lives, thereby guarding against the alternative of deteriorating performance and increasing costs.

Our plans would also ensure that we continue to build levels of customer satisfaction and continue to build on our already significant achievements in relation to safety and the environment.

ESCOSA's Draft 2005 – 2010 Electricity Distribution Price Determination

In the Draft Determination, ESCOSA has acknowledged:

- The requirement to increase investment in the network; and
- ETSA Utilities' high levels of efficiency in comparison with other distributors.

However, as part of the same determination, ESCOSA has proposed to reduce ETSA Utilities' revenues by on average $10 million per annum over the next five years when compared with the previous five.

[5] Excluding the impacts of new functions such as Full Retail Contestability which cannot be considered in a like-for-like comparison.

These revenue reductions have resulted from ESCOSA establishing parameters in the Draft Determination which will see ETSA Utilities':

- **Return on Equity** reduced such that other privatised, regulated Australian utilities, on average, would receive 27% higher returns;
- **Regulated Asset Base (RAB)** effectively reduced by $130 million;
- **Expenditure Benchmarks** set 17% lower on a like-for-like basis than the lowest allowances of any other Australian electricity distributor.

These reductions are based upon analysis and reasoning that fails to comply with ESCOSA's legislative requirements and, as a result, would undermine ETSA Utilities' ability to fund the required network investment.

Such an outcome is not in the long term interests of South Australian electricity consumers and would be a fundamental error by ESCOSA.

A guide to reading this submission

In this report, we consider the key issues that have led to this unsatisfactory outcome, and point out errors that ESCOSA has made in undertaking its analysis and reasoning. The report is structured to consider in turn, the most significant issues of:

- Return on Assets;
- Expenditure Benchmarks (allowances); and
- Financial Impact Assessment.

The subsequent three sections deal with further issues that require redress including:

- Sales Forecasts;
- Pass-throughs; and
- Prescribed and Excluded Services, focussing primarily on the ESCOSA's proposed profit share scheme.

We acknowledge that in relation to sales forecasts, ESCOSA has already requested an updated forecast from its consultants. Our previously documented concerns in relation to the previous forecast are however restated within this document.

Minor wording, interpretational and technical issues have been excluded from this response with the expectation that discussions will continue with ESCOSA staff on these matters. A preliminary response on part B of the Draft Determination has been provided to ESCOSA however this cannot be completed until ESCOSA has finalised its determination on all other matters.

A number of appendices have also been included to provide independent support or additional information in relation to some of our key conclusions.

B. Return on Assets

B.1 Introduction

In Chapters 9 and 10 of the Draft 2005-2010 Electricity Distribution Price Determination, ESCOSA sets out its views in relation to return on assets, a function of decisions made in relation to the value of the regulatory asset base and the determination of the real pre-tax WACC. In its Draft Determination, ESCOSA has:

- Effectively reduced the regulated asset base by more than $130 million. This is through reductions in the required working capital allowance[6] and a change to the building block formula. The financial analysis in Chapter 14.1 assumes that ESCOSA can reduce the regulated asset base by more than $130 million without impacting on ETSA Utilities' capacity to finance its debt and provide a suitable return to equity holders. These changes significantly undermine the jurisdictional asset base established by the South Australian Government and approved by the ACCC.

- Reduced the margin allowed above the risk free rate by some 33 percent. ESCOSA has achieved this through further reducing the required return on equity, so much so that the return on equity above the average real risk free rate for other fully privatised NEM electricity network providers is now a full 27% above that allowed in the Draft Determination.

Despite offsetting increases resulting from increased expenditure benchmarks, ESCOSA's Draft Determination would see **ETSA Utilities' revenues reduced on average by $10 million per annum over the next regulatory period when compared to the last**.

In net present value terms, the implications of the Draft Determination are even more concerning and should be a serious concern to ESCOSA. Reductions to the allowance for return on equity compared to other privatized, regulated network providers equates to $200 million in net present value terms. This does not include the impact of changes from the current Electricity Pricing Order (EPO) such as reducing the market risk premium from 6.5 to 6.0 percent or increasing gamma from 0.3 to 0.5 but includes the reduction in the equity beta from 1.0 to 0.8. When combined with the effective reductions to the regulated asset base the total cost to ETSA Utilities' equity holders is around $330 million.

ESCOSA's Draft Determination has reduced the value of the business by around $330 million. Accordingly, the investors in the business will, contrary to the reasonable expectations, suffer a loss of $330 million on their investment with the prospect of further such serious losses if this regulatory trend is maintained in future price determinations.

These are extraordinary financial shocks that are being applied by ESCOSA. To compound the effect, there was no ability to prepare for them or even foresee them at the time of the original investment as they are completely inconsistent with the regulatory processes and signals from the State at that time. In addition, the financial analysis undertaken by ESCOSA in Chapter 14.1 is flawed and cannot be relied upon to address the impact of the Draft Determination on ETSA Utilities' commercial viability.

ETSA Utilities is concerned that inadequate consideration has been given to the long-term interest of customers or the South Australian economy which are closely aligned to ensuring continuing investment in the electricity distribution network.

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[6] When adjusted for inflation this is the approximate difference between the old working capital allowance and the new working capital allowance.

We address in this section matters of fundamental concern where ESCOSA has erred in the performance of its statutory function and misapplied the regulatory regime that governs the exercise of the price setting function. In particular, this section of the submission discusses the following matters:

- the parameter value applicable to equity beta;
- the interrelationship of market risk premium and gamma;
- the value attributable to substation land and easements; and
- the building block formula.

B.2 Equity Beta

ESCOSA's draft conclusion that the appropriate equity beta to be applied is 0.8 is wrong and should not be maintained in the final Price Determination. An appropriate equity beta in the circumstances should not be below 1.0.

B.2.1 Context

Under both the Electricity Pricing Order and the National Electricity Code, in the present circumstances ESCOSA is required to have regard to:

(a) the prevailing conditions in the market for investments having a similar nature and degree of business risk as those faced by ETSA Utilities (clause 6 of schedule 10 of the Electricity Pricing Order); and

(b) beta factors that can be observed for companies that have business risk profiles and capital structures similar to those of ETSA Utilities (clause 3.3 of schedule 6.1 of the National Electricity Code).

B.2.2 ESCOSA's Conclusions

ESCOSA has made at least 3 findings concerning the conclusion to be drawn from the 'current' or the 'latest' market evidence concerning equity beta namely:

(a) at page 171, ESCOSA concluded that "if the Commission were to have regard exclusively to the latest market evidence, it would adopt a re-levered equity beta of approximately 0.3"[7], apparently based on what is recorded in table 10.1;

(b) at page 172, ESCOSA concluded that "if the Commission were to place exclusive reliance on the current market evidence, a beta of 0.82 would be considered appropriate for a regulated Australian electricity distributor"[8], apparently based on what is recorded in table 10.2; and

(c) at page 177, ESCOSA also concluded that "the latest market evidence would suggest an equity beta… of less than 1.0, if regard is had to the estimates that are obtained at the end of each quarter of the period since September 1999".

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[7] ESCOSA however did not adopt an equity beta of 0.3 because of concerns about statistical imprecision, variation as a result of changes in the composition of a sample group and variation of individual beta estimates and the risk that such a beta factor may reflect a short term aberration.

[8] The 95% confidence interval for the 0.82 figure is, however, extremely broad being 0.35 to 1.29.

B.2.3 Appropriate Methodology

It should not be contentious that in order to make a proper evaluation of the appropriate equity beta, ESCOSA must:

(a) have reliable observations for a reasonable period of time such as 3 to 5 years;

(b) ensure that the definition of returns and market portfolio used are appropriate;

(c) pay regard to the trends observed in the beta factors;

(d) consider whether historical estimates of beta factors are likely to be a reliable predictor of the future, in the current circumstances;

(e) consider whether individual or groups of beta estimates are economically or commercially implausible and so should be excluded from any analysis; and

(f) apply standard statistical techniques such as standard errors and confidence levels to assess what market evidence is sufficiently precise and robust to be relied upon by ESCOSA given the risks associated with regulatory error in determining revenue controls for the South Australian distribution network.

Similarly, problems in determining equity betas from scarce or disparate market data which has some or all of the characteristics set out below, must be addressed in a methodologically and commercially sound manner:

(a) statistical imprecision in the estimation of equity beta;

(b) variation as a result of changes in the composition of the sample group;

(c) variations in individual beta estimates;

(d) the risk that beta factors may be affected by short term aberrations;

(e) the impact of the "technology bubble" on the stock market on observed betas;

(f) significantly differing levels of debt leverage requiring the application of re-levering procedures to ensure a true comparison;

(g) the implausibility of negative equity beta calculations.

ESCOSA has failed to take account of the need to refine its use of the market data given the existence of these characteristics notwithstanding that:

(a) of the 5 companies used in the comparative analysis 2 are, in addition to having electricity interests, gas retailers and distributors;

(b) the betas of the companies vary widely – 0.05 to 2.03 for weekly sampling and 0.19 to 0.73 for monthly sampling whereas the expectation for equity betas is that they are constant over long periods;

(c) the proxy group is a very small number of companies and, for the majority of the period September 1999 to March 2004, data for many of the companies was not available;

(d) removing outliers has a significant effect on the calculation of equity beta for individual companies. Some of the more influential outliers reflect data that is not representative of the long term position or likely to have any relevance to a "looking-forward" analysis;

(e) the confidence levels associated with a crude "averaging" of these values to obtain a "representative" industry beta, namely an outcome of plus or minus 0.47, emphasises the unreliability of the use of such data in this way;

(f) there is no allowance for the fact that ETSA Utilities operates substantially in rural areas and therefore has a higher risk level than the remainder of the sample and therefore requires a higher equity beta.

Accordingly it is ETSA Utilities' submission that ESCOSA has not taken account of the prerequisites for a proper analysis of the appropriate equity beta to be applied in this case.

Further, while there are well established or standard statistical techniques and practical adjustments that can be made to deal with or allow for the data problems referred to above, ESCOSA has failed to employ these techniques and make the required adjustments, in particular, to take a simple arithmetic average of the mid points of various confidence ranges without further analysis, consideration of the underlying data or adjustment to respond to the various characteristics detailed above, is methodologically unsound and therefore inconsistent with the requirements of clause 6 of schedule 10 of the Electricity Pricing Order and clause 3.3 of schedule 6.1 of the National Electricity Code.

As a result, ESCOSA's conclusions concerning what the "current" or "latest" market evidence shows are fundamentally flawed and wrong.

B.2.4 Correct Methodology

ETSA Utilities' contention is that if the market data is accurately and properly considered and adjusted to address the characteristics detailed above, ESCOSA would not conclude that an equity beta of less than 1.0 is appropriate.

ETSA Utilities relies upon the draft report of Professors Officer and Gray and the report of NERA (refer attachments 2 and 3) provided to ESCOSA in October 2004 to illustrate the errors in ESCOSA's approach to equity beta and notes that other jurisdictional regulators have recently made decisions supporting an equity beta of 1.0. Experts advising jurisdiction regulators have also concluded that an equity beta of 1.0 is appropriate.[9]

Whilst ESCOSA has listed other regulators' decisions on equity betas in table 10.4 and concluded that "regulators have adopted a range of between about 0.7 and 1.2, with many adopting 1 (or approximately 1)" (page 177) this is not an adequate analysis of this information.

ESCOSA's analysis is further undermined by the fact that what is stated to represent equity beta by way of a range in fact does not reflect the equity beta adopted by the relevant regulator but rather the range identified by the relevant regulator from which it derived an equity beta. Thus while the IPART, 2004 decision for NSW distributors is stated to be a range of 0.78 to 1.11 the final calculation of tariffs indicates that IPART in fact adopted an equity beta very close to 1.0[10].

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[9] See ACCC's Final Statement of Principles for the Regulation of Electricity Transmission Revenues dated 8 December 2004, in which an equity beta estimate of 1 is adopted. See also Allen Consulting Group, Electricity Networks Access Code 2004: Advance Determination of a WACC Methodology, Report to the Economic Regulation Authority, WA, dated January 2005 where ACG recommends an equity beta of 1.

[10] IPART provided a range of values for equity beta and other parameters. This provided for a range in the real pre-tax WACC of 6.1 percent using the low parameter values and 7.5 percent at the other end of the scale (the parameter range for equity beta was between 0.78 and 1.11 with the midpoint

It is fundamentally wrong where a regulator identifies a range for the purposes of ascertaining equity beta to say that any value within that range has equal integrity and credibility. In fact, at the extremities of the range there are lower levels of confidence and at the mid point of the range higher levels of confidence. As a result, in the instances where ESCOSA has relied upon a range, it has done so by ignoring the actual value of equity beta which was derived from that range. The same situation has occurred with respect to the equity beta used in the initial tariffs in the Electricity Pricing Order where the range reflects different gearing levels but the actual equity beta, reflecting the assumed gearing level, was 1.0.

Only 1 out of 20 decisions, being the QCA for electricity distribution, arrived at an equity beta factor as low as 0.71 and that was in relation to government business enterprises not private sector firms. Further, QCA has recently revised its equity beta estimate to 0.9.[11] Whilst it might be literally true to say that "regulators have adopted a range between about 0.7 and 1.2", to suggest, as ESCOSA does, that its choice of an equity beta of 0.8 for a private firm has validity and is appropriate because it is "within the range adopted by regulators", is to misuse that data.

In fact, properly evaluated and giving precedence to those decisions which relate to the private sector, the other regulators' decisions support the conclusion that an equity beta of at least 1.0 is appropriate in the present case.

ESCOSA must now, on its own analysis, reconsider its draft Price Determination because it can no longer rely on 0.71 as indicating one extreme in the data spread as that decision has now been revised to 0.9.[12] This data spread cannot properly be considered a range of decisions all comparable to the decision to be made by ESCOSA because a number of the decisions are specific to the relevant regulated entity. As ESCOSA acknowledges, decisions setting an equity beta for a Government owned and operated business are of little relevance to ETSA Utilities (making the QCA decision of 0.9, which in any event is specific to the circumstances in Queensland, not a valid comparison). In fact the most significant piece of data to be derived from the table is that the equity beta's for private sector industries are very close to or in excess of 1.0.

It is important for ESCOSA to acknowledge that the range of regulatory decisions on equity beta does not, of itself, create a basis or a platform for ESCOSA to select any value within that range. ESCOSA must make its own decision based upon the Electricity Pricing Order and National Electricity Code, the market data and the circumstances of the South Australia jurisdiction and the business conducted by ETSA Utilities within that jurisdiction.

The primary significance of the regulators' decisions is not the fact that they are other regulators' decisions. Their significance is that the regulators were engaged in the same exercise as ESCOSA, namely, determining an appropriate equity beta that reflects market conditions and business risk profiles for businesses similar to ETSA Utilities for the purpose of regulation of their revenue and pricing in the context of the Australian energy market.

As such, rather than just recording the results of the regulators' consideration, ESCOSA should also give cogent reasons for departing from those decisions in the present case, if ESCOSA has reached a different view as to the appropriate equity beta. To fail to do so would mean that ESCOSA is not complying with section 6(1)(b)(vii) of the Electricity Act given that this is an

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0.945). The real pre-tax WACC allowed by the Tribunal was set well above the mid-point of this range at 7.0 percent suggesting that the equity beta adopted by the Tribunal must also therefore be above the midpoint of 0.945 and hence was effectively set at very close to 1.0.

[11] See QCA: Draft Determination, Regulation of Electricity Distribution dated December 2004.

[12] QCA: Draft Determination, Regulation of Electricity Distribution dated December 2004

instance of the Electricity Pricing Order where there is such a consistency between the regulatory instruments that it is appropriate to maintain consistency with other regulators.

It is ETSA Utilities' position that, properly evaluated, the other regulators' decisions support the conclusion that an equity beta of at least 1.0 is appropriate in the present case.

Moreover, this is consistent with the "null-hypothesis" position, viz, absent compelling market evidence to the contrary, the assumed equity beta of a firm should be 1.0. As is clear from the analysis, the only way that ESCOSA can extract an equity beta of 0.82 is to assume a low confidence level consistent with a plus or minus margin of 0.47. This is not compelling market evidence which would support a deviation from the null-hypothesis of 1.0.

ESCOSA's analysis is also inconsistent with the guidance provided by Schedule 6.1 of the National Electricity Code that, where domestic beta data is not available, to use the beta factor estimated by observing comparable lists of Australian and overseas companies. The data of comparable overseas companies derived from a much larger sample group, as analysed in the reports previously provided by ETSA Utilities to ESCOSA and attached to this report, supports an equity beta of 1.0.

Finally, in terms of consistency, ESCOSA has not had regard to the provisions of the National Electricity Code which require it to have regard to decisions made in the determination of the initial tariffs – see clauses 6.10.2(g) and 6.10.3(iv)(A) of the National Electricity Code. As noted above, the equity beta assumed in determining the initial tariffs was 1.0 (not the range referred to by ESCOSA in its table on page 176). Further, the equity beta assumed in determining the initial tariffs moves closer to 1.2 when adjusted to reflect the 60 percent level of gearing assumed by ESCOSA in the Draft Determination.

ESCOSA has offered no evidence to suggest, if that was the appropriate market beta in 1999, that the market has changed so dramatically in respect of the differentiation between the business risk of ETSA Utilities as compared to a general market portfolio. There is no basis for taking the risk of undermining investor confidence in this business that arises from such a dramatic change from 1.0 to 0.8, particularly when the increase in the gearing assumption is taken into consideration.

B.2.5 Consequences for ETSA Utilities

ESCOSA has failed to acknowledge or appreciate the consequences of an error which underestimates equity beta.

Unlike other regulated entities, revenue on ETSA Utilities' regulated asset base represents some 50 percent of ETSA Utilities' total revenue. Moreover, a further investment of up to one third of ETSA Utilities' capital asset base will be required over the next five years. As such ETSA Utilities is highly vulnerable to a decision which determines equity beta lower than the correct value.

Not only is ETSA Utilities vulnerable to such an incorrect determination of equity beta, but so are the electricity consumers of South Australia. Section 6(1)(A) of the ESC Act specifies as ESCOSA's primary objective "the protection of the long term interest of South Australian consumers with respect to price, quality and reliability of essential services".

An equity beta of 0.8 will create an investment climate inconsistent with the long term interest of consumers with respect to the quality and reliability of distribution services. In this respect, the risk of regulatory error is asymmetric. Under estimating equity beta will have serious adverse effects upon the quality and reliability of the distribution network which, as the Queensland distribution network will attest, has significant adverse community

repercussions and takes a very long period of time to redress. On the other hand, over estimation of equity beta brings forward investment, a situation which can be largely addressed in subsequent price resets as a financial adjustment rather than the need to deal with the impact on the community of unreliability of the distribution network. Moreover, ETSA Utilities notes that there is no evidence in the Australian market that an equity beta of 1.0 has caused such over investment.

In the light of the errors in ESCOSA's Draft Determination detailed by ETSA Utilities in this submission and previously on this topic, ETSA Utilities request ESCOSA revise its conclusions in relation to the appropriate equity beta so as to properly analyse the data available and to comply with ESCOSA's obligations as arising under the Electricity Pricing Order and the National Electricity Code. When doing so, ESCOSA should also consider and set out explicitly its consideration of:

(a) the risk of regulatory error and the likely consequences of such error; and

(b) how its conclusions are in the long term interests of South Australian electricity consumers,

in relation to its final position on equity beta compared to other available choices of equity beta so as to justify that outcome as the most appropriate regulatory result.

B.3 The inter-relationship between Market Risk Premium & Gamma

ETSA Utilities in its response to the Return on Assets Preliminary Views Paper issued by ESCOSA in January 2004 strongly submitted in relation to market risk premium and gamma that ESCOSA had not provided sufficiently robust reason to depart from the parameter values initially set by the South Australian Government.

The parameter values initially set by the South Australian Government were 6.5 for market risk premium and 0.3 for gamma. For reasons set out in previous submissions, ETSA Utilities consider that these parameter values better reflect prevailing conditions in the market for investments having a similar nature and degree to ETSA Utilities' business risks, as required by Schedule 10 of the EPO, than the parameter values proposed by ESCOSA.

Nonetheless ESCOSA, in its Draft 2005-2010 Electricity Distribution Price Determination, retained its Preliminary Views Paper position. That is, parameter values have been seemingly set at the lower end of the reasonable range of values with market risk premium set at 6.0 and gamma at 0.5.

ESCOSA's Draft Electricity Distribution Price Determination is unclear as to whether the estimate of the market risk premium that has been adopted (6.0 percent) includes the value of franking credits.

If it is assumed that the 6.0 percent value attributed to market risk premium includes the value of franking credits then this implies that market risk premium from dividends and capital gains has been set at a level that is not only amongst the lowest in the developed world but more importantly dramatically lower than all available empirical evidence, however determined. Such a decision cannot be said to reflect 'prevailing conditions in the market' for investments having a similar nature and degree of business risks as those faced by ETSA Utilities' and accordingly is not in compliance with Schedule 10 of the Electricity Pricing Order.

The data sources quoted by ESCOSA to justify market risk premium at 6.0 percent do not include in their estimates the value of franking credits. Accordingly, it appears more likely that ESCOSA in setting market risk premium at 6.0 percent has not included the value of franking credits. Therefore, to the extent a value is attributed to franking credits (remembering ESCOSA has set gamma at 0.5), then this must be added to this estimate of market risk premium. In the case of gamma being set at 0.5, then market risk premium should be significantly higher than 6.0 percent.

ETSA Utilities requests ESCOSA specifically deal with this matter in its Final Determination. If ESCOSA retains a gamma at 0.5, then ESCOSA must, if it is to comply with Schedule 10 of the Electricity Pricing Order, either:

- reflect this value in the parameter value of market risk premium which does not appear to currently be the case; or
- advise why market risk premium from dividends and capital gains is to be set at a value that is amongst the lowest in the developed world.

B.4 Substation Land and Easements

It is the view of ETSA Utilities that:

- ESCOSA's proposed treatment of easements and substation land directly conflicts with the terms of the Electricity Pricing Order;
- ESCOSA's proposed treatment of easements and substation land directly conflicts with the terms of the National Electricity Code;
- ESCOSA's proposed treatment of easements and substation land directly conflicts with ESCOSA's treatment of other assets falling within the scope of clause 7.2(e)(iv) of the Electricity Pricing Order, namely working capital and work in progress when there has been a substantive 're-valuation' albeit to an amount not accepted by ETSA Utilities in the case of working capital;
- ESCOSA's proposed treatment of easements and substation land is directly inconsistent with the expectations created by the Government of the State of South Australia in the privatisation of the distribution network; and
- ESCOSA's proposed treatment of easements and substation land is in direct conflict with the principles for the determination of tariffs which permit a distributor to recover a reasonable return on the asset base used in the provision of distribution network services.

Accordingly, ETSA Utilities submits that if ESCOSA were to maintain this treatment of easements and substation land in its final Price Determination, these errors would invalidate its determination because of the operation of Section 35B(13) of the Electricity Act.

B.4.1 Meaning of "Value"

It is ETSA Utilities' position that ESCOSA has made an error in its application of the concept of "value" where appearing in both the Electricity Pricing Order and the National Electricity Code. In those instances, the word "value" has its normal meaning as described in the Shorter Oxford English Dictionary as:

> *"(1) that amount of some commodity, medium of exchange, etc., which is considered to be an equivalent of something else; a fair or adequate equivalent or return;*
>
> *(2) the material or monetary worth of a thing; the amount at which it may be estimated in terms of some medium of exchange or other standard of a like nature."*

ESCOSA has not provided an analysis showing that $6 million represents the value of easements in the sense either of their "worth" or in the sense of any other alternative method of "valuing" such easements.

Rather, ESCOSA relies exclusively on the fact that $6 million was used for the purposes of the calculation of the initial tariffs to show that this "necessarily" meant that the easements had been valued at that amount.

In this respect, ESCOSA has made the error of using "value" as having the same meaning as "amount" in the same way that when an algebraic formula is applied, particular "values" are attributed to particular elements of that algebraic formula.

This misapplication of the concept of "value" by ESCOSA means that its treatment of easements and substation land in the Draft 2005 Price Determination is in error.

B.4.2 Application of the Electricity Pricing Order and National Electricity Code

The Electricity Pricing Order was created as a result of a derogation to the National Electricity Code contained in clause 9.29.4 of the National Electricity Code. That clause permitted the distribution service pricing to be developed by the South Australian Government "in accord with its own specific criteria and methodologies". The terms of the derogation were consistent with general principles for distribution pricing contained in Chapter 6 of the National Electricity Code which expressly permitted differences in the price setting instruments for distribution pricing to reflect local conditions – see clause 6.10.1(a)(3) of the National Electricity Code.

As ESCOSA has pointed out, the emphasis given to the statements of policy contained in the Electricity Pricing Order was intended to be given effect to by subsequent jurisdictional regulators – see clause 6.10.2(g) of the National Electricity Code requiring that the jurisdictional regulator must give:

> *"reasonable recognition of pre-existing policies of governments which are Distribution Network Owners regarding distribution asset values, revenue paths and prices"*

and clause 6.10.3(iv)(A) which requires ESCOSA to have regard to:

> *"relevant previous regulatory decisions made by authorised persons including the initial revenue setting and asset valuation decisions made by a government at a time at which that government was a Distribution Network Owner in the context of industry reform pursuant to the Competition Principles Agreement"*

Accordingly, bidders in the privatisation process had good reason to rely upon the terms of the Electricity Pricing Order in relation to the subsequent price setting for distribution services. The State benefited from that reliance in the privatisation proceeds derived.

This is the context that the relevant terms of the Electricity Pricing Order must be considered.

B.4.3 The Pre-Existing Policy Position on Easements

Schedule 9 of the Electricity Pricing Order applies at the time of the 2005 price reset and any subsequent price reset. Schedule 9 has no role to play with respect to the initial tariffs.

Schedule 9 identifies those assets which have been the subject of a valuation in accordance with the National Electricity Code. Schedule 9 also explicitly nominates those assets which have not been valued. Those latter assets included easements and substation land.

It had not been possible for ETSA Utilities to provide a valuation of easements because, whilst it had engaged valuers to determine the value of those easements for particular regions, it was not in the position to take the "rates" of valuation applicable to a specific region within South Australia and apply them to easements in those regions as it lacked the data to do so. The SA Government had no choice but to proceed with privatisation without the valuation of easements at that time.

The solution was to attribute an amount of $6 million to the easements in the calculation of the initial tariffs and to provide in the Electricity Pricing Order for a procedure which:

- identified in Schedule 9 that easements had not been valued and therefore the amount attributed to easements in the initial tariffs was not "locked in" as was the case for the other assets listed in Schedule 9; and
- provided in clause 7.2(e)(iv) of the Electricity Pricing Order that consideration be given to valuing those assets which were not in the Asset Schedule, including easements.

What should be apparent from clause 7.2 and Schedule 9 is that there is no support for the view that the amount of $6 million represents the pre-existing policy position as to the "value" of the easements.

Although, in its Draft 2005 Price Determination ESCOSA did not do so, it is necessary to examine the source of the $6 million amount in order to see whether it represents any form of qualitative assessment of the "worth" of the easements such as to qualify the amount as a "value".

What has been identified from previous submissions of ETSA Utilities to ESCOSA (which is apparently now not contradicted by ESCOSA) is that the $6 million which appeared in the accounts of the government owned entity, ETSA Utilities Pty Ltd, did not represent an amount determined as a result of a valuation of any form. In fact, all the evidence is that ETSA Utilities was not, at that time, in a position to derive a value of the easements because it was not in a position to identify the extent of the easements in the various locations around the State so as to apply the valuation rates applicable to those regions.

What ETSA Utilities did at the time was to review an incomplete set of data as to costs incurred by ETSA Utilities in relation to acquisition of certain of its existing easements. It was incomplete in two respects namely:

- it reflected data held by ETSA Utilities as to expenses incurred in relation to the acquisition of certain of its easements; and
- in relation to those easements where the data was collected, it was incomplete as to those expenses.

Accordingly:

- the treatment of easements in the financial accounts of ETSA Utilities Pty Ltd, was entirely rational and logical. It was not a valuation because no valuation was available. It was not a record of costs incurred in acquiring all the existing easements because that information was not available;

- the SA Government faced with the reality of an inability to establish the value of the easements and simultaneously with the pressing program for privatisation, used the 'book value' for the purposes of calculation of the initial tariffs but then specifically recorded in the Electricity Pricing Order that there had been no valuation of the easements and that a value should be ascribed to those easements in the 2005 price reset.

This was never intended to be a windfall for the successful bidder for the distribution network. What was intended by the State was that bidders would have to make an assessment of the revenues for the 2005 to 2010 period for the purposes of their bid and the effect of easements being valued for the 2005 price reset would reflect positively in their bids. In effect, bidders were expected to "pay" for the treatment of easements in this fashion with the successful bidder being the one prepared to pay the most.

The absence of complete data as to the costs of acquisition of easements for a government owned distribution or transmission network is not unique to ETSA Utilities. Other jurisdictional regulators and the ACCC have had to deal with this problem when considering the treatment of assets for purposes of a regulated asset base. The approach adopted by the ACCC and elsewhere has been to recreate that historic cost by sampling the costs of acquisition of easements in particular cases, "benchmarking" those costs against best practice to ensure that the costs were not excessive, and then applying those benchmark sample costs across the extent of the easements held in relation to a particular electricity network.

By way of cross check to confirm that $6 million did not represent any meaningful representation of the cost of the easements, ETSA Utilities retained SKM to perform the same task for ETSA Utilities and determine the benchmark indexed historic cost of easements.

That analysis is contained in attachment 1. That attachment shows an indexed historic cost for easements of $118.8 million. What this illustrates is that the ACCC endorsed method of approximating indexed historic cost where complete data is not available produces an amount so greatly in excess of $6 million as to corroborate conclusively that $6 million has no relevance as an assessment of the worth of the easements for the distribution network in South Australia.

B.4.4 Correct Methodology

ETSA Utilities' position is that, as ESCOSA has failed to make out a basis for the use of $6 million as a valuation of the easements, ETSA Utilities is entitled to have a value ascribed to those easements.

ETSA Utilities' submission is that, unless ESCOSA undertakes a valuation of the easements in the manner consistent with clause 6.10.3(e)(5)(ii) of the National Electricity Code, this will constitute a fundamental error in the Price Determination. ETSA Utilities however acknowledges that there is some force to the arguments previously relied upon by the ACCC and other jurisdictional regulators that easements, being an interest in land, are different in character to "wasting" assets such as the physical infrastructure of the distribution network.

It is ETSA Utilities' position that this difference is best addressed by applying the optimised deprival method of valuation subject to one adjustment. That adjustment would distinguish

between the value of easements insofar as reflecting the value of the bundle of rights conferred on the distribution entity by the easements and that part of the value of the easement that reflects the value of the underlying freehold land on which the easement is located. It is the fact that in modern times freehold land values have increased substantially, particularly in areas of high local amenity, which has meant that the application of the optimised deprival method of valuation provides valuations which have been described as providing a "windfall" to distributors or "price shock" to consumers if applied unadjusted.

ETSA Utilities' submission is that it would be reasonable for ESCOSA to determine the value of easements on the basis of optimised deprival value having removed from that valuation all but a base element of the value of the freehold land on which the easement is located.

ETSA Utilities would be happy to assist ESCOSA in identifying the data necessary to undertake this form of valuation.

The ACCC has offered an alternative view namely that the indexed historic cost of acquisition of the easements should be used as a method of valuation.[13] For the reasons already mentioned it is not possible to establish the actual indexed historic cost of acquisition of all the existing easements.

However, as ESCOSA has noted on page 146 of the Draft Price Determination, the ACCC appears to have endorsed the view that electricity transmission assets could be valued at their current cost of acquisition. In this case ETSA Utilities' cost of acquisition of the easements and substation land is $276.2 million. If ESCOSA were minded to adopt that method of valuation then that would be an appropriate historic cost of acquisition for valuation purposes.

B.4.5 Commentary on specific elements of ESCOSA's draft decision

ESCOSA takes the position that clause 6.10.3(e)(5)(iii) of the National Electricity Code is not triggered because there is no "revaluation" of the easements occurring at this time. ESCOSA's view is that whilst, it must "ascribe" a value to the easements under clause 7.2(e)(iv), doing so by adopting the position consistent with the amount used for the purposes of the initial tariffs is not a "revaluation". Whilst it is not explicit from ESCOSA's Draft Price Determination, the inference from the reasoning is that ESCOSA justifies that position on the basis that, as there is no change between the two amounts, there is therefore no "revaluation".

ETSA Utilities' position is that the amount used in the initial tariffs was not a valuation and that clause 7.2(e)(iv) requires a value to be considered for the first time. In this situation ETSA Utilities submits that the value should represent some concept of worth.

It is therefore ETSA Utilities' position that the process to be applied by ESCOSA in relation to the 2005 Price Determination cannot, by definition, be regarded as the same process used to determine the initial tariffs.

On pages 145 to 149, ESCOSA seeks to support its conclusion that the appropriate value of the existing easements should be taken to be $6 million by reference to other statements of regulatory principle and decisions. The consistent regulatory position provides no support whatsoever for the retention of a value of $6 million.

[13] See ACCC Statement of Principles for the Regulation of Electricity Transmission Revenues ("SORP") – Background Paper, 8 December 2004, in particular pages 135-136.

ESCOSA's statement at page 145 of the Draft Price Determination that the ACCC has never issued a final version of the draft Statement of Principles for the Regulation of Transmission Revenues is no longer correct. A final decision and background paper were issued by the ACCC on 8 December 2004. While the valuation of easements is touched upon in various places, Appendix C (pp. 135 – 136) deals specifically with the issue.

For various reasons, the ACCC concludes that the DORC methodology "may be inappropriate"[14] for valuing easements and considers that the indexed historic cost approach is "the most appropriate asset valuation methodology for easements" (ACCC background paper 8 December 2004 page 135). Where records of historical costs actually paid are unavailable or incomplete, the ACCC recommends a benchmarked indexed historical cost approach.[15]

ESCOSA's characterisation (at page 147 of the Draft Determination) of regulatory decisions concerning distribution networks as "reasonably consistent – in particular, easements have either not been ascribed any value, or only a nominal value (consistent with a book value for the asset)" is neither a fair summary of the decisions nor relevant as at least one has little if any applicability in the present case. Indeed, such a characterisation is inconsistent with ESCOSA's summary of the "weight of precedent" being in favour of the indexed historical cost methodology.

In particular:

(a) The Victorian Government's decision in 1995 not to include a separate value in respect of easements in the opening regulatory asset bases (page 147 of the Draft Determination) and instead to use an aggregated value of land and infrastructure is irrelevant. The South Australian Government adopted a contrary approach in the Electricity Pricing Order - see in particular, clauses 7.2(e)(iv) and 7.3(b)(iv). Further it is difficult to perceive how the Victorian Government's position is consistent with the National Electricity Code and clause 7.2(k)(i) of the Electricity Pricing Order.

(b) The final QCA decision referred to by ESCOSA at pages 148 and 149 adopted an indexed historical cost approach. Again, it is an error to characterise this as ascribing no value or only a nominal value to easements.

B.4.6 Reconsideration by ESCOSA

In the light of:

(a) the errors in ESCOSA's Draft Determination identified above; and

(b) ETSA Utilities' submissions made in this submission and previously,

ETSA Utilities requests ESCOSA to revise its conclusions in relation to the valuation of the existing easements so as properly to take into account this material and so as to comply with ESCOSA's obligations including those arising under the Electricity Pricing Order and the National Electricity Code.

[14] The ACCC does not say that it should never be used.
[15] See page 136 of the ACCC SORP 8 December 2004 background paper.

B.5 The Building Block Formula

ESCOSA, in its Draft 2005-2010 Electricity Distribution Price Determination, set revenue benchmarks in accordance with what is termed Equation 2, as set out on page 153 of the Draft Determination. This is a significant departure from the methodology applied in setting the revenue benchmarks for the initial tariff period, where return on capital was set in accordance with what ESCOSA refer to as Equation 1 (also defined on page 153).

The impact of changing the building block formula is to reduce the regulatory asset base, upon which the return on capital is determined, by more than $70.0 million.

It is ETSA Utilities' position that, if this methodology was maintained in the final Price Determination, it will be inconsistent with the EPO and NEC and therefore invalid by virtue of the operation of Section 35B(13) of the Electricity Act.

B.5.1 The Electricity Pricing Order

Interpretation of the regulatory regime without regard to its context is an error highlighted in the EPIC Energy Case[16] where the court held the regulator had not interpreted the *Gas Code* correctly by relying exclusively on the principle of economic efficiency in its determination of the asset base. The court found the regulator failed to have regard to the reasonable expectations of investors and stated:[17]

> *"the nature and conditions of the tender process by which the State sold and Epic purchased the DBNGP would be circumstances which might properly be considered."*

The Electricity Pricing Order is the prime element of the regulatory process that ESCOSA must apply in making its Price Determination. Its intent was to minimise investor risk by providing a high degree of regulatory certainty, particularly with respect to determining the asset base at future reviews. In particular, investors' attention was drawn to the certainty conferred by the Electricity Pricing Order that, in both of the next two regulatory periods, the asset base would only be adjusted within carefully defined parameters.

The Draft 2005-2010 Electricity Distribution Price Determination, in changing the building block formula, is plainly inconsistent with the intent of the Electricity Pricing Order as it produces an outcome that was not and could not reasonably have been anticipated on privatisation and is inconsistent with the State's decision on the building block formula as applied in the initial tariff period. Contrary to the requirements of Clauses 6.10.3(iv)(A) and 6.10.2(g) of the NEC ESCOSA has not had regard to the policy decision to adopt Equation 1 made by the initial Regulator in setting the initial tariffs. ESCOSA is in error in not acting consistently with that original policy decision.

The intention of the Electricity Pricing Order to provide regulatory certainty is evident from the Second Reading Speeches made by the Treasurer of South Australia in connection with the introduction of the legislation restructuring the South Australian electricity industry. In the second reading speech, introducing the Independent Industry Regulator Bill, the Hon RI Lucas (Treasurer) stated on 6 August 1998:

> "*The Independent Regulator's powers in respect of pricing will be subject to an electricity pricing order to be issued by the Government to provide certainty for buyers and consumers in the transition to a privatised industry.*"

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[16] Re: Dr Ken Michael AM; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231.
[17] Ibid paragraph 172.

The Treasurer stated on the same day, in respect of the Electricity (Miscellaneous) Amendment Bill:

> "*The proposed new section [section 35D] empowers the Treasurer to make an initial electricity pricing order. A date is to be fixed by proclamation before which any such order must be made. It will then take effect on the day fixed in the order and will not be capable of being varied or revoked except by amendment of the Act. …The Industry Regulator will be responsible for making calculations and determinations under the order from time to time and is to enforce the order in the same way as a pricing determination made by the Industry Regulator. While the order is in force the Industry Regulator's powers with respect to pricing determinations will be restricted to the extent specified in the order.*"

Comments of a similar nature were made by the Treasurer in June 2000 when it was found necessary to amend the Electricity Pricing Order by legislation to correct calculation errors. An example appears in Hansard on 29 June 2000 where, speaking about the Electricity Pricing Order made under section 35B(1) of the Electricity Act and the provision prohibiting any variation of that order contained in section 35B(7)(b) of the same Act, the Treasurer stated:

> "*This provision was included to give some certainty to both electricity supply participants and their customers at a time of considerable change brought about by the introduction of the National Electricity Market and the privatisation of the State's electricity businesses.*"

Investors were encouraged to place considerable weight on the certainty of the Electricity Pricing Order in their valuations of ETSA Utilities in order to be competitive in the bidding process for the distribution network. The change to the building block formula effectively reduces the regulatory asset base upon which the business earns its annual revenues in a manner that could not have been foreseen on privatisation and causes a real loss to the business. In doing so it undermines the intent of the Electricity Pricing Order and is inconsistent with the initial revenue setting policy of the initial Regulator which investors would reasonably expect to be followed by subsequent Regulators by virtue of the Code provisions quoted above and clause 1.11 of the EPO.

Investors expectations were cultivated by a number of documents (either public or provided to bidders in the privatisation process) issued prior to sale. They emphasised the Electricity Pricing Order's purpose of promoting regulatory certainty. These documents include the Information Memorandum issued by the Treasurer in 1999, which states: [18]

> *"For the two regulatory periods that immediately follow the first regulatory period, the SAIIR must use the asset base set out in Schedule 9 of the EPO (which is based on the valuation of the distribution network assets undertaken by Sinclair Knight Merz), adjusted to account for inflation, depreciation, capital expenditure and disposals in the ordinary course of business, as well as other assets necessary to enable ETSA Utilities to provide prescribed services, including easements;"* (emphasis added)
>
> "*Under the EPO, ETSA Utilities' revenue will be regulated using a revenue yield and CPI - X approach, building on the experiences in Victoria and the United Kingdom, to provide increased incentives and certainty. … Increased regulatory certainty is also provided at the reset for the next regulatory period from 1 July 2005 through guidance being provided to the SAIIR in respect of the determination of the rate of return and the Regulated Asset Base.*" (emphasis added[19])

The Information Memorandum when highlighting the key risks to investors asserts:[20]

> *"Beyond 2005 the SAIIR will set tariffs for future regulatory periods. However, the EPO gives guidance to the SAIIR by specifying broad regulatory parameters with which the SAIIR must abide in making future price determinations for subsequent regulatory periods. These parameters include:*
>
> - *the value of initial assets;"*

That the initial asset base was intended not to be the subject of an arbitrary downward adjustment is supported by the analysis carried out by NERA, the ACCC's consultants at the time the Electricity Pricing Order was authorised. NERA's (1999) review of the Electricity Pricing Order states: [21]

> *"the initial asset base of ETSA Utilities cannot be optimised in the next two regulatory reviews (or at least ETSA Utilities will not bear any revenue loss if these assets are optimised)."*

This intent to provide future asset base certainty is embodied in Clauses 7.2(e) and 7.3(b) of the Electricity Pricing Order. To the extent there may be room for different interpretations of these clauses, section 22 of the *Acts Interpretation Act 1915* requires that ESCOSA interpret them with regard to the purpose of the Electricity Pricing Order, which as demonstrated by the documents quoted from above, was clearly to provide asset base certainty for the next two regulatory periods.

In a competitive bidding process investors had to rely on the initial valuation methodologies and the building block formula to calculate their return on capital for the next two price resets. To now change the formula, and effectively reduce the asset base upon which a return on capital is determined, was not and could not reasonably have been anticipated at the time

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[18] Electricity Reform and Sales Unit, *ETSA Utilities and ESTA Power: Information Memorandum*, Vol. 1, 30 August 1999.

[19] Volume 1, page 5.

[20] Provision 8.8.1.

[21] NERA, The South Australian Electricity Pricing Order: A Review – Final Report for the ACCC, November 1999, p52.

of privatisation and is inconsistent with the intent of the Electricity Pricing Order and the NEC. The Electricity Pricing Order does not contemplate altering the methodology by which the benchmark revenue allowance is determined. To change the building block formula undermines the assurance provided by the Electricity Pricing Order in relation to the value of the regulatory asset base.

ESCOSA is of the view that a prudent investor would have assumed that a future regulator would reassess the approach taken in determining the tariffs applying in the first regulatory period.

ESCOSA is essentially arguing that a prudent investor should have foreseen that a future regulator would seek to undermine the regulatory asset base by more than $70.0 million, through a change to the building block formula, and in doing so depart from the methodology used to derive initial tariffs. This reasoning is flawed and is directly contrary to the expectations created by Clauses 6.10.2(g) and 6.10.3(iv)(A) of the Code and clause 1.11 of the EPO.

A prudent purchaser, to whom representations had been made that the Electricity Pricing Order had been enacted to promote regulatory certainty and certainty as to the asset base upon which the return on capital is determined, would rightly assume ESCOSA would apply that Order in a manner consistent with its purpose.

The building block formula applied by the Government and its advisors to calculate the benchmark revenue at privatisation was known to investors through material in the Information Memorandum and the submission by the South Australian Electricity Reform and Sales Unit to the ACCC on the Electricity Pricing Order.

As this formula was critical to understanding the impact of future regulatory decisions, and given the espoused purpose of the Electricity Pricing Order, it was reasonable for investors to assume that ESCOSA would retain the formula for at least the next two price resets.

The proposal to change this formula causes a significant loss to investors. This loss is not consistent with the underlying purpose and intent of the Electricity Pricing Order as read in the context of the distribution pricing principles contained in Chapter 6 of the NEC.

ESCOSA's proposed change effectively reduces the asset base, is inconsistent with the intent of the Electricity Pricing Order and NEC and introduces another level of regulatory risk. This regulatory risk is exacerbated by ESCOSA's statements to the effect that Equation 2 over-compensates for the cost of capital. These risks are not compensated for in the allowed rate of return and further increase the chance that the long run cost of capital is higher than ESCOSA's allowed return on capital.

B.5.2 Regulatory Practice

ESCOSA remarks that other Australian energy regulators generally adopt either one of two target revenue formula, referred to as Equation 2 and 3 on page 153 of the Draft 2005-2010 Electricity Distribution Price Determination. However, ESCOSA is in error in considering the formula in isolation from the other elements of the modelling used in the other jurisdictions.

Equation 3 expresses the ACCC's current methodology for providing a return on capital in allowable revenues. ESCOSA's analysis is in error in that it overlooks the explicit return on capital expenditure provided by the ACCC in any given year. Examination of the ACCC's recently released new post-tax revenue model suggests that the ACCC's methodology is

similar to ESCOSA's current return on capital formula, ie Equation 1[22]. The ACCC has stated that it is reasonable to assume that:

> *"the commissioning date for investment projects is spread evenly over the year, providing half vanilla WACC on the cost of capital projects adequately compensates the TNSP"*[23]

The effect is the ACCC does not include the cost of capital for new capital expenditure in the revenues for the year; instead the capital expenditure is scaled up by (½*WACC) when it enters the asset base at the end of the year. In effect the ACCC provides a return on capital similar to Equation 1 with:

- WACC*Open AV_t given in revenue in year t: and
- WACC $*\left(\frac{Capex_t}{2}\right)$ capitalised in the asset base at the end of year t.

Australian regulators have, both at a jurisdictional regulator and ACCC level, attempted to preserve the integrity of initial asset valuations. IPART recently considered this very question in evaluating whether or not to revalue the asset base in its draft decision for electricity distributors. IPART's decision not to adjust the asset base was influenced by the argument that revaluations which are not specifically mandated in the relevant regulatory regime (and therefore, by definition, unforeseeable) added an unnecessary degree of regulatory uncertainty as well as being inconsistent with the financial view of the asset base.[24]

The absence of a statement of policy in the EPO that a change to the building block formula was to be considered at subsequent tariff re-sets has given rise to a reasonable expectation that no change would be made to the methodology for deriving the revenue benchmarks. Given this expectation at the time investors bid for ETSA Utilities, it would be an error to assume it did not influence the price paid to the South Australian government or that there would be a windfall effect if Equation 1 continued to be applied in the 2005 Price Determination.

B.5.3 Draft 2005-2010 Electricity Distribution Price Determination

ESCOSA state:

> "*However, the Commission considers that the current methodology is incorrect and provides a windfall to ETSA Utilities. This is inconsistent with the objectives and principles outlined in the NEC, including the objectives of prevention of monopoly rent and of having regard to the principle of balancing the interests of Distribution Network owners and network users with the public interest".*

ESCOSA suggest that the building block formula adopted in the first regulatory period is self-evidently inappropriate and accordingly should be varied, a position which puts it directly in conflict with Clauses 6.10.2(g) and 6.10.3(iv)(A) of the NEC. The current building block formula that is reflected in the Electricity Pricing Order adopts the normal commercial conventions used by businesses, analysts and investment bankers – including using spreadsheet software with its own 'assumptions' built into the way in which standard formulae are programmed. ESCOSA implies that a potential investor should have been aware that such a

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[22] ACCC, PTRM electricity module and handbook, 22 December 2003.
[23] ACCC, Post-Tax Revenue Model – Electricity Module Handbook, December 2003, p 14.
[24] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09: Draft Report, January 2004, p 46.

variation would need to be made to the building block formula. In response to this we note that:

(a) the approach taken as to the appropriate building block formula (and other matters in the Electricity Pricing Order) was consciously determined by the Treasurer of South Australia and the Treasurer's advisers in exercise of the explicit authority contained in the NEC[25] to adopt pricing methodologies specific to South Australia;

(b) the approach was approved by the ACCC in approving the Electricity Pricing Order; and

(c) the approach was protected by Clauses 6.10.2(g) and 6.10.3(iv)(A) of the NEC.

In respect of paragraph (a), we note the following remarks made by the Treasurer in a letter to Allan Asher (then Deputy Chairman of the ACCC) dated 2 December 1999:

> "*The South Australian Government believes the rate of return used in the EPO to be reasonable …*
>
> *With respect to the other significant parameters underlying the initial revenue determinations … critical elements of the underlying parameters, such as the valuation of assets, have been reviewed independently, and I believe that work undertaken by advisers and consultants to the South Australian Government as part of the process of developing the EPO has involved significant and expert review of all other relevant matters.*
>
> *…the regulatory regime is in fact both innovative in the way it incentivises industry participants to make efficiency gains and in the best interests of South Australian consumers.*"

In short, having regard to the detailed development and approval process which surrounded the creation of the Electricity Pricing Order, ETSA Utilities considers ESCOSA is in error in concluding that the approach taken to the building block formula in the Electricity Pricing Order is intrinsically wrong or inequitable. The methodologies used to establish the initial tariffs represent conscious policy positions taken by the South Australian government as to the manner in which distribution network tariffs should be determined. The fact that different regulators, applying different pricing instruments, may choose to adopt a different approach does not render the decisions taken by the South Australian government incorrect or inappropriate to follow in relation to distribution pricing in this jurisdiction.

[25] See clause 9.29.5 of the NEC (as it existed at the time of the EPO), clause 6.10.1(a)(3) and 6.10.1(f) of the NEC.

C. Expenditure Benchmarks

C.1 Introduction

In the Draft Determination, ESCOSA has proposed to establish expenditure benchmarks that represent reductions of approximately 17% to the Expenditure Submission put forward by ETSA Utilities.

This sizeable reduction has resulted from the acceptance of the majority of recommendations of ESCOSA's consultants, PB Associates and PKF, and the application of additional reductions considered appropriate by ESCOSA's Commissioners.

In undertaking a review of ETSA Utilities' proposed expenditure, ESCOSA has indicated[26] that it is required to determine the "operating and capital expenditures that an efficient distributor [operating in South Australia] would need to incur over the regulatory period", giving consideration to:

- Benchmarking;
- Cost Drivers; and
- Trend Analysis (comparing expenditure incurred in the current regulatory period to that proposed by ETSA Utilities).

ETSA Utilities believes that ESCOSA's proposed reductions to the Expenditure Submission are based on fundamental errors, namely that they are unreasonably severe, do not adequately address the items requiring consideration, and would provide ETSA Utilities with expenditure benchmarks that are inadequate to optimise long term expenditure on the distribution network.

In particular, ESCOSA has:

- Failed to adequately consider benchmarking information in forming its views;
- Inadequately considered the drivers of costs, and particularly the impact of cost escalation, that collectively have led to ETSA Utilities proposing significant expenditure increases in the next period; and
- Incorporated <u>additional</u> expenditure reductions beyond those recommended by its consultants in a review that ETSA Utilities considers was already overly aggressive in seeking cost reductions on the basis of flawed assumptions[27].

These issues are addressed in the following sections.

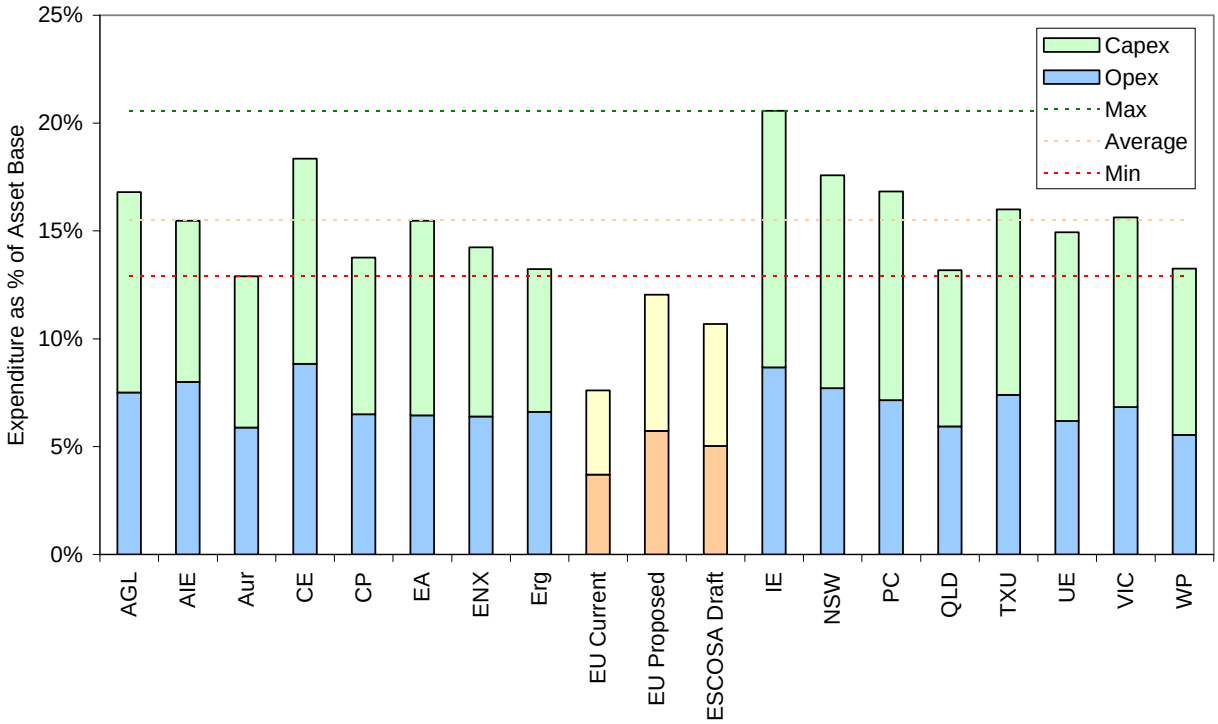
[26] Electricity Distribution Price Review Framework, Discussion Paper, March 2002, p14 – 15.
[27] In their initial review, PB Associates inappropriately benchmarked ETSA Utilities on the basis of operating expenditure including transmission use of system (TUOS) fees thereby overstating ETSA Utilities' benchmark position by a factor of two.

C.2 Benchmarking

ETSA Utilities appreciates that benchmarking is only one of the factors used to evaluate the expenditure plans submitted by ETSA Utilities. Our plans were developed from a "bottom-up" basis, and PB Associates also undertook their review in this fashion. Nevertheless, benchmarking is an important contextual factor that must be considered when undertaking a review.

The diagram below shows ETSA Utilities' current allowances, proposed expenditure, and ESCOSA's Draft Determination "benchmarks" in relation to other Australian distributors.

Figure 4. Capital & Operating expenditure allowances[28]



Although some commentators have criticised ETSA Utilities for selectively showing benchmarks in relation to the regulated asset base, alternate benchmarking undertaking by PB Associates illustrates the same result, as do a range of other indicators.

The conclusions that can be drawn are clear:

- ETSA Utilities' current allowances have been significantly lower than industry norms; and
- ESCOSA's Draft Determination still provides ETSA Utilities with allowances that are significantly lower than the rest of the industry.

The first point is critical as it puts the expenditure increases proposed by ETSA Utilities into context. They are required to bring ETSA Utilities' expenditure back into line with industry norms and to levels that are sustainable and efficient in the long term. It is important to understand also that these expenditure plans had already been moderated by ETSA Utilities from those developed bottom-up from a technical basis as it was recognised that such a large ramp-up in expenditure could not occur in such a short time-frame.

[28] ETSA Utilities' figures show 2006 proposed expenditure. Other networks show 2005 allowances.

PB Associates did not acknowledge this context until late in their review. Their initial benchmarking had indicated that ETSA Utilities' operating expenditure was around industry norms, but this was because they had inadvertently included TUOS in the figures thereby doubling ETSA Utilities' apparent expenditure. ETSA Utilities believes that PB Associates' failure to reflect this context in their analysis led them to follow an unreasonably aggressive approach to cost reductions in their review. Despite numerous subsequent representations by ETSA Utilities, these aggressive reductions have flowed through to ESCOSA's Draft Determination.

ESCOSA appears to acknowledge this context, and has stated that benchmarking indicates:

> *"… despite the significant increase in operating expenditure submitted by ETSA Utilities, the business would remain relatively efficient in comparison to many other electricity distribution businesses in Australia."*[29]

As illustrated above, ETSA Utilities would not only remain "relatively efficient", but would remain the <u>most</u> efficient.

Nevertheless, ESCOSA has chosen to reduce ETSA Utilities' submitted expenditure by some 17% on the basis of "more detailed assessment". The flaws in this assessment are discussed in the following sections.

C.3 Expenditure Increases & Cost Drivers

In the next regulatory period, ETSA Utilities' costs will be influenced by a number of key cost drivers including:

Capital Expenditure:

1. The need to significantly increase **Reinforcements and Upgrades** expenditure, having undertaken a range of initiatives in the current regulatory period that have led to uncharacteristically low expenditure;
2. Continued increases in volumes of **Customer Connection** work, and increased net costs of this work, resulting from ESCOSA's proposed changes to the customer contribution calculation methodology in combination with general economic growth; and
3. A need to begin addressing the emerging issue of growing numbers of assets reaching the end of their effective lives, driving increased **Asset Replacement and Refurbishment** expenditure.

Operating Expenditure:

4. Expenditure required to fulfil ETSA Utilities' responsibilities in relation to **Full Retail Contestability**;
5. New costs associated with piloting **Demand Management** schemes; and
6. Some increased **Maintenance** expenditure to better optimise maintenance programs by reducing maintenance backlog and increasing inspections to deal with recently identified risk factors.

[29] Draft 2005-2010 Electricity Distribution Price Determination, Part A – Statement of Reasons, Nov 2004, p11.

7. Requirements to implement ESCOSA's new **Service Standard Framework** including implementation of the Outage Management System and a significantly expanded Guaranteed Service Level scheme;

And more broadly:

8. Increasing expenditure requirements associated with real escalation of labour and services costs over the next regulatory period.

Although ESCOSA has accepted increased expenditure associated with some of these drivers, ESCOSA has not taken account of others, or proposed significant reductions in the expenditure proposed.

In particular:

- **Reinforcements & Upgrades** expenditure has been cut by $44 million[30] based on PB Associates (flawed) analysis that suggested some projects could be delayed;
- **Labour cost escalation** has been curtailed to levels inconsistent with any reasonable expectations;
- **Services cost escalation** has been curtailed to CPI; and
- No expenditure has been allowed to implement the new **Service Standard Framework**.

These issues are considered in detail in the following sections.

C.4 Reinforcements & Upgrades

This cost category relates to the upgrade or construction of new substations and lines to deliver increased network capacity in response to general demand growth, not associated with any specific new customers. General demand growth could occur, for example, in line with increasing demand per customer due to installation of increasingly large air-conditioners and a range of other factors.

In its Draft Determination, ESCOSA has reduced ETSA Utilities' proposed expenditure on reinforcements and upgrades from $239.3 million to $195 million. This is a reduction of some $44 million; accounting for nearly 35% of the capital expenditure reductions proposed by ESCOSA.

ESCOSA's expenditure benchmarks are based largely on analysis undertaken by PB Associates, who in their final report stated that ETSA Utilities' proposed expenditure increases in the Reinforcements and Upgrades cost category reflect a position that is conservative and will reduce ETSA Utilities' risk profile over the next regulatory period.

ETSA Utilities has rejected this position in previous submissions to both ESCOSA and PB Associates but have still not received a substantive response. We re-state our key points below:

- ETSA Utilities <u>is</u> seeking significant increases in this area of expenditure. We can therefore appreciate why considerable scrutiny has been applied in this area. We agree that this is entirely appropriate.

However, it must be understood that:

[30] Including $13 million of potential pass-through amounts in relation to connection point projects.

- Plans in this area are developed from the "bottom-up" to ensure that network capacity can meet customer demand growth in specific areas of the network. They follow a set of defined rules known as "planning criteria" to identify network constraints - areas where supply cannot meet demand.
- Although the cost driver (Peak Demand Growth) in South Australia has remained quite steady over a long period, capacity related expenditure may experience peaks and troughs due to the nature of the planning process.
- In the next regulatory period, capacity related expenditure must significantly increase from the current period. This is required because:
    1. Various initiatives over the recent past have led to artificially low substation related capacity expenditure as excess capacity in the network has been utilised[31]. This means that on average, we have been installing less capacity than required to match customer growth, thereby increasing asset utilisation. This cannot occur indefinitely.
    2. Expenditure on the sub-transmission network is extremely peaky due to the low number of lines in the network and their high level of interdependence. Large proportions of the network tend to become overloaded at the same time. Major components of this network must be upgraded within the next regulatory period.

In developing our plans, ETSA Utilities has proposed:

- No change to our current planning criteria, which effectively define the level of risk under which we operate the network, thereby containing the risk of significant supply interruptions to customers.
- No change to our risk profile from the commencement to the end of the new period other than minor shifts which occur from year to year as a result of projects being undertaken and/or new constraints arising.
- A slight increase to our asset utilisation over the next regulatory period.

PB Associates has stated that once projects are more fully analysed, significant cost reductions or deferrals may be possible. PB Associates provide a list of potential "solutions" in their report that may allow such reductions or deferrals to occur.

These solutions however would create a range of risks including:

- A requirement to alter ETSA Utilities' planning criteria and risk profile thereby increasing the risk of major supply interruptions to customers;
- A reliance on demand management or embedded generation solutions that CRA have already indicated are unlikely to realise net gains in the next regulatory period;
- No consideration of additional costs resulting from the proposals;
- Failure to optimise whole-of-life costs; and
- In some cases, a breach of the Transmission Code.

Furthermore, no consideration is given to other factors that may increase costs over those forecast or require projects to be advanced rather than deferred.

[31] To a large extent, this has been enabled through delaying capital projects by introduction of mobile substations. This provided a one-off gain that cannot be expected in future periods.

As a result of their analysis, PB Associates proposed significant reductions to ETSA Utilities' expenditure in this area. This would be a fundamental error given that PB Associates' review found:

- No areas where an inappropriate solution has been proposed;
- No network or substation constraints that are incorrect or exaggerated; and
- No projects that are not required according to ETSA Utilities' published Planning Criteria.

To achieve the cost reductions indicated, PB Associates has proposed that an unprecedented level of risk be adopted in ETSA Utilities' Planning Criteria for contingency conditions. Deferrals of the magnitude recommended will also lead to overloads of line assets at peak load times. That is, the network could be overloaded under peak load conditions, even without a contingency event (fault) occurring.

The only solution to such overloads is to disconnect customers ("load-shed"). For example, if the Southern Suburbs project were delayed by three years as recommended by PB Associates, the Happy Valley to Panorama 66kV lines will become overloaded under peak load (heat-wave) conditions, requiring up to 10,000 customers to be disconnected from supply.

Furthermore, despite a common misconception that such impacts would be spread evenly across all customers, this is not the case. Customers within the regions affected by specific constraints arising during the period will receive extremely poor service, with a significantly increased risk (or certainty in some cases) of having to be disconnected during heat wave conditions, whereas the service levels to other customers in non-constrained areas would be entirely unaffected.

We believe that the adoption of such a philosophy will be detrimental to business confidence in South Australia through lack of certainty in the reliability of the State's electricity supply infrastructure. Residential customers will also become highly frustrated as a result of outages occurring primarily during heat-wave conditions.

ETSA Utilities seeks that reductions to Reinforcements and Upgrades expenditure, on the basis of inappropriate and unsubstantiated project deferrals or reductions, be reversed in ESCOSA's Final Determination.

C.5 Internal Labour Cost Escalation

This section has been removed from the publicly available version of ETSA Utilities' submission owing to the sensitive commercial nature of its content.

C.6 External Goods & Services Cost Escalation

This section has been removed from the publicly available version of ETSA Utilities' submission owing to the sensitive commercial nature of its content.

C.7 Implementation of the new Service Standard Framework

In the Draft Determination, ESCOSA propose in regard to Business Relations expenditure that:

> *"The Commission supports expenditure by ETSA Utilities on educating consumers of their rights and obligations and in promoting safety awareness. However, it believes that escalation of current allowances is an appropriate level of funding for this purpose."*

By purely escalating (rolling forward) current allowances, and allowing no expenditure on additional initiatives, ESCOSA fail to take into account the considerable analysis that ETSA Utilities has undertaken to determine and focus on customer needs and will provide ETSA Utilities with no allowance to undertake research to further refine service provision over the next period.

Further, such an assessment fails to acknowledge the real additional costs that ETSA Utilities will need to incur in the implementation of the new Service Standard Framework, the scope, complexity and administrative burden of which will require:

- A re-write of ETSA Utilities' Customer Charter and a significant education effort so that customers understand their new rights;
- Additional personnel and systems to administer the scheme;
- An expectation of greater levels of customer enquiries to both ETSA Utilities and the Electricity Industry Ombudsman in relation to the new scheme.

It is noted that PB Associates approved such expenditure whilst ESCOSA has chosen not to take account of their advice.

The new Service Standard Framework is seen as a significant move forward by ETSA Utilities, but it will not be successful unless adequate funding is devoted to its communication and administration.

ESCOSA must re-instate reasonable expenditures in order for ETSA Utilities to comply with its obligations to implement the new Service Standard Framework.

C.8 Detailed Issues

Further to these high level issues, a number of reductions to expenditure have been proposed by PB Associates and/or ESCOSA that appear to be arbitrary and/or have no clear basis.

a. Mobile Radio Network Replacement

On pages 100 and 101 of ESCOSA's Draft Determination, reference is made to ETSA Utilities proposing to upgrade its SCADA system and implement a "customer relationship management" (CRM) system. PB Associates are described as not deeming either of these projects to be prudent.

As referenced in prior correspondence to ESCOSA and PB Associates, these projects were withdrawn from ETSA Utilities' Expenditure Submission part-way through the review as it was identified that urgent asset replacement work should receive a higher priority and the two projects were replaced by the Mobile Radio Network replacement project. Despite ETSA Utilities' continuing requests, both ESCOSA and PB Associates continue to reference the SCADA and CRM projects, and no evaluation has been carried out on the Mobile Radio project.

ETSA Utilities' Mobile Radio Network comprises a statewide system of (generally) single channel analogue repeaters and is used to coordinate switching on the electrical network between field crews and ETSA Utilities' Network Operations Centre. The system can also be used as a back-up to other communications systems (eg. the public telephone network) in emergency situations or when crews are out of range of other commercial mobile phone services.

The system is critical for ETSA Utilities' operation of the network and the safety of personnel. Public networks cannot be used owing to the risk of them becoming overloaded under emergency or state disaster situations.

The current network has been in place for between 20 and 30 years and contains equipment which is becoming obsolete and is no longer supported by manufacturers. ETSA Utilities' own spares holdings have now also become depleted and short-term replacement is essential so as to ensure the radio network is not subject to long-term outages thereby placing ETSA Utilities under operational risk, and resulting in associated safety and reliability issues for customers.

ETSA Utilities seeks to have this project properly reviewed and the project expenditure reinstated in our expenditure allowances for 2005 – 2010.

Table 1. Proposed Mobile Radio Replacement Capital Expenditure ($000)

	2005/06	2006/07	2007/08	2008/09	2009/10
Mobile Radio Network Replacement	4,340	4,694	1,927	-	-

b. NEMMCO B2B Interfaces

In PB Associates' review of ETSA Utilities' Expenditure Submission, and subsequently in ESCOSA's Draft Determination, expenditure for upgrades to systems to comply with NEMMCO requirements has been disallowed.

In their report, PB Associates incorrectly (as has been pointed out in previous communications) assumed that the B2B capital expenditure is associated with the manual processing work-arounds discussed in our operating expenditure submission.

This is not the case. These expenditure items are independent.

The B2B capital expenditure is required for compliance with NEMMCO requirements, and reflects implementation of a new NEMMCO "information portal". This is an industry-wide requirement from NEMMCO and not just specific to ETSA Utilities.

ETSA Utilities is required to comply with these NEMMCO obligations[32] from the 23 October 2005 for all Tier 2 customers. NEMMCO are proposing to extend these obligations for Tier 1 customers by means of a Code Change in 2005. These procedures will then be the default procedures for Tier 1 customers unless there is unilateral agreement between the Retailer and the Distributor. Regardless of what arrangements will occur with respect to Tier 1 customers, we must implement the new systems for Tier 2 customers. Our submitted expenditures are to allow for this to occur.

These system changes represent an additional interface layer, above and beyond that currently implemented within ETSA Utilities, and will not replace current interfaces or negate the need for manual processing.

ETSA Utilities seeks to have this expenditure re-instated in our capital expenditure benchmarks.

Table 2. Proposed NEMMCO B2B Interface related expenditure ($000)

	2005/06	2006/07	2007/08	2008/09	2009/10
NEMMCO B2B Interfaces	2,384	1,192	993	795	993

c. Substation Fencing

The Electricity (General) Regulations 1997 state that all substations must be designed, installed, operated and maintained to be safe for the electrical service conditions and the physical environment in which they will operate. Further, the Regulations require that fences "must be constructed of a substantiative material (such as brick, masonry, sheet metal or galvanised chain-wire mesh) and be at a minimum height of 2.5m".

ETSA Utilities is legally required to meet its general duty of care obligations. Failure to do so exposes ETSA Utilities to the risk of significant claims for damages and financial penalties resulting from injury or death. In the event of a serious breach of its duty of care, resulting in death, there exists the possibility of manslaughter charges. Sentences of imprisonment can be imposed under current OH&S Legislation.

The findings from a recent interstate court case (following the fatality of a child within a substation) on what constitutes a reasonable level of security for a substation fence concluded that such fencing should exceed the minimum requirements outlined in the applicable Australian Standards (AS1725).

[32] NEMMCO published their final determination in relation to the MSTATS Procedures B2B procedures on the 23 December 2004. This is available on the NEMMCO website.

Subsequently, the Electricity Supply Association of Australia (ESAA) embarked on producing the "National Guidelines for Prevention of Unauthorised Access to Electricity Network". This guide recognises that "no fence will prevent access by a determined person, persons with tools or persons with intent". It adds that the "purpose of the guide is to provide a reasonable level of security … to limit the likelihood of access by unskilled intruders such as children".

Whilst this guideline is still in draft form (as at February 2005), the principles have already been adopted by a number of interstate Distribution and Transmission Authorities. In appropriately exercising our duty of care and managing ETSA Utilities' legal risks, it is imperative that we can demonstrate consistency with standards applied by other industry participants.

ETSA Utilities' current fencing generally meets or exceeds the requirements of the Electricity Regulations however upgrades are required to comply with the new ESAA guideline. It has been proposed that a program be undertaken over 10 years to undertake upgrades to meet the guideline, with an initial focus on sites of particularly high risk.

In their review of ETSA Utilities' proposed expenditure, PB Associates, following from discussions with the Office of the Technical Regulator (OTR), stated that:

> *"The OTR is fully aware of the ESAA work and has provided verbal confirmation to PB Associates that the guideline does not place any additional mandatory requirements on ETSA and that the decision to upgrade substation fences, on the basis of the ESAA guideline, should be at the discretion of ETSA.*
>
> *PB Associates defers to the OTR in this matter and therefore concludes that the decision to upgrade substation fences is a business decision for ETSA based on their normal business risk management strategy and any cost-benefit considerations associated with good asset management practice …"*

ETSA Utilities agrees with the OTR's assessment however disagrees with the conclusion that the expenditure is therefore "imprudent" and/or would not reasonably be incurred by "an efficient distributor". We seek to have this expenditure re-instated in our expenditure benchmarks.

Table 3. Proposed Substation Fencing Capital Expenditure ($000)

	2005/06	2006/07	2007/08	2008/09	2009/10
Substation Fencing	2,522	2,571	2,623	2,676	2,945

d. Bushfire Self-insurance

In ETSA Utilities' Expenditure Submission, a notional insurance cost was included in relation to self-insurance for bushfire related claims under the $5 million deductible currently incorporated into ETSA Utilities' bushfire insurance policy[33].

In relation to this item, ESCOSA has asserted in the Draft Determination that:

> *"… there does not appear to be any material change in circumstance from the 2000-2005 regulatory period that could justify an increase in expenditure above current levels."*

On this basis, the expenditure was disallowed.

[33] It should be noted that such insurance and self-insurance specifically excludes any provision for recovery of costs associated with damage to distribution infrastructure resulting from such bushfires.

Further clarification of the issue with ESCOSA has led to an understanding that the disallowance was on the basis that it had been assumed that expenditure in relation to self-insurance was already in the "base" expenditure[34] submitted by ETSA Utilities.

Although the base expenditure did include some self-insurance provision, this was largely that related to the typical claims received each year by ETSA Utilities.

Actual expenditure in the current regulatory period is however not necessarily a good predictor of appropriate notional self-insurance costs in the next period.

There are in fact two issues here:

1. Whether notional self insurance costs should be an allowable expense to a regulated business; and
2. How such costs might be determined.

In relation to the first issue, in the ACCC's recent (December 2004) release of its "Statement of principles for the regulation of electricity transmission revenues", the ACCC has stated in relation to self-insurance that:

> *"Insurance is a legitimate cost of doing business. The ACCC will recognise an efficient allowance for insurance. Self-insurance implies that rather than paying a premium to an underwriter to accept a risk, the business has decided to accept the risk itself. The decision to self-insure rather to obtain insurance from a third party or remove risk altogether by building out, is a commercial decision.*
>
> *The ACCC would like TNSPs to respond to regulatory efficiency incentives by seeking the most economical way to manage the risks that they face. If self-insurance is the most efficient way to manage a risk, then the ACCC would like to ensure that TNSPs are able to pursue this course." (p69)*

It is important to note that the ACCC recognises that the level of self-insurance does not relate to the level of risk that the business is exposed to, it is purely a means of managing a risk.

In the case of the bushfire insurance deductible (up to $5 million), ETSA Utilities has determined that self-insurance is the most efficient means to manage this risk.

In relation to the second issue of how the cost of such self-insurance might be determined, ETSA Utilities has sought to use the market value of such insurance as a proxy for such self-insurance costs. As we have been unable to source a market premium for the full deductible between $0 and $5 million, we have incorporated instead the value of a policy to reduce the deductible to $1 million. As such, this represents a very conservative view of the notional market value of such self-insurance.

We seek to have this reasonable allowance re-instated into our expenditure allowances for the next regulatory period.

Table 4. Proposed Bushfire Self-Insurance Expenditure ($000)

	2005/06	2006/07	2007/08	2008/09	2009/10
Bushfire Self-Insurance	812	820	828	837	845

[34] Comprising actual expenditure for the first half of the financial year 2003/04 and forecast expenditure for the second half.

e. Access to Electricity Meters

As a component of our Expenditure Submission, ETSA Utilities' proposed additional expenditure to enable compliance with ESCOSA's recent decision to enforce requirements under the Metering Code to undertake at least one physical read every 12 months (rather than estimating consumption) for customers whose meters could not readily be accessed.

Under the proposal, customers would be provided with an additional notification on the 3rd estimated read and special arrangements would be made on the 4th read (assuming 3 monthly reads). Follow-up would also be undertaken after the 4th read if required. These new requirements would require additional personnel and changes to computer systems, thus increasing costs.

PB Associates did not include these costs within their recommendations for ETSA Utilities' expenditure, based on advice from ESCOSA.

Discussions are continuing with ESCOSA as to whether it wishes to build such costs into ETSA Utilities' prescribed expenditure benchmarks, or would seek for us to recover them through an excluded services charge.

We would anticipate that we will be given the opportunity to provide appropriate costings for inclusion in our expenditure benchmarks at such time, and if, ESCOSA determine that such costs should be recovered by ETSA Utilities within prescribed revenues.

D. Financial Impact of Draft Determination on ETSA Utilities

This section has been removed from the publicly available version of ETSA Utilities' submission owing to the sensitive commercial nature of its content.

E. Sales Forecasts

E.1 Introduction

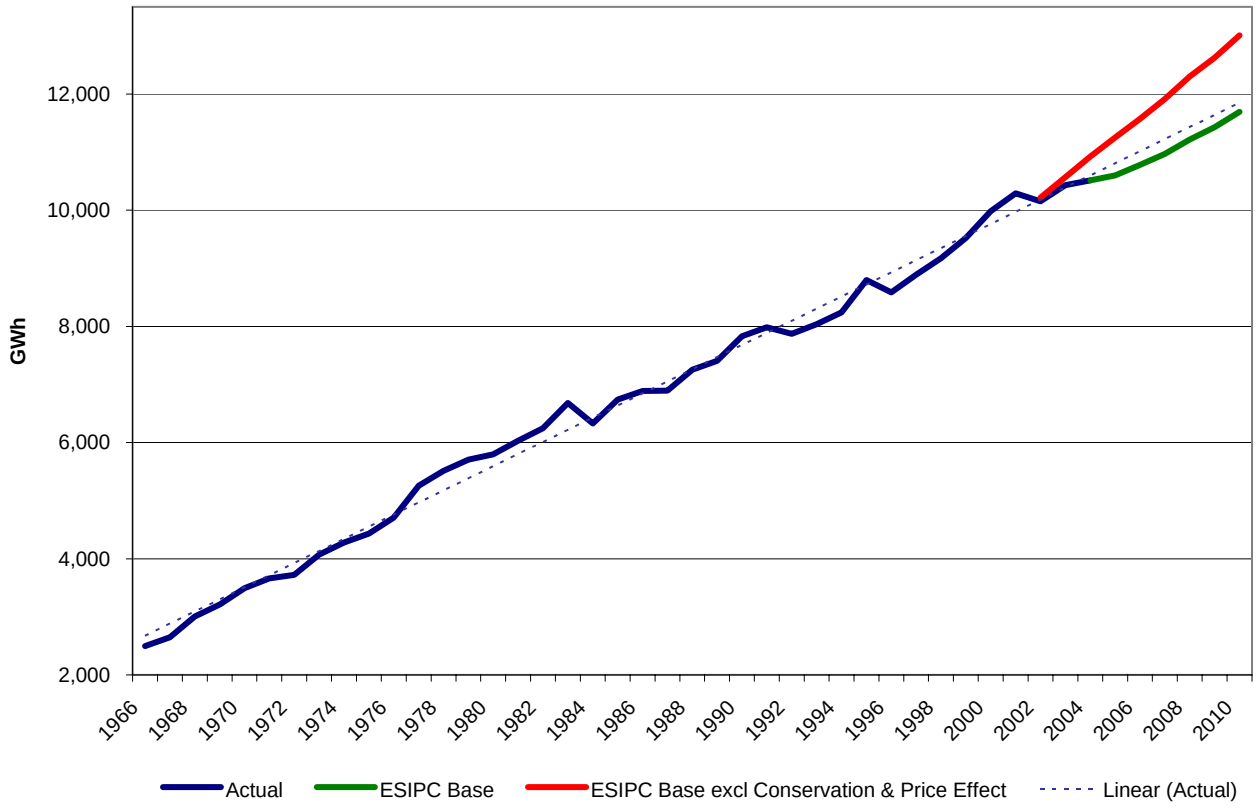
Sales forecasts for ETSA Utilities will be a critical part of the final determination. Depending on the revenue control mechanism, a significantly higher forecast than is actually experienced will prevent ETSA Utilities from recovering its allowable costs. Conversely, forecasts that are too low will unreasonably increase prices for customers.

In the current regulatory period, ETSA Utilities has experienced significant sales shortfalls arising from customer responses to electricity retail price rises and from changing attitudes to the environmental implications of electricity usage. These changes were beyond the reasonable control of ETSA Utilities and did not reduce ETSA Utilities' costs.

The task of forecasting electricity usage is inherently difficult as evidenced by the experience of the current regulatory period.

In response to the original sales forecast provided by ESIPC in September 2004, ETSA Utilities expressed concern with the underlying sales growth projections, particularly given the current Government policy focus on energy efficiency related to achieving reductions in greenhouse gas emissions.

Figure 6. Effective underlying total sales forecast[35]



ETSA Utilities' October 2004 response also provided additional information and analysis in relation to sales data and trends that was not available for the original forecast.

[35] Total sales with base price effect and conservation effect added back in.

In response to ETSA Utilities' concerns and in consideration of the new data, ESCOSA requested that ESIPC conduct an interim re-forecast, based on the most recent information in the areas of observed electricity sales, customer number trends, South Australia's economic performance and so on. The Draft Determination utilised the 'interim' sales re-forecast, and required that a more comprehensive re-forecast be conducted in February 2005.

ETSA Utilities' key concerns with the original ESIPC September forecast are summarised below.

E.2 Starting Point of Forecasts

ETSA Utilities believes that the sales forecasts should utilise the weather-adjusted sales history in determining the starting point for the next period, and exclude the effects of the 2004 leap-year. The original ESIPC forecast used actual 2003/04 sales as the starting point of its forecasts.

E.3 Price Effect

The original ESIPC forecast quantified the observed and projected impact of the 2003 electricity retail price rise. However, when weather adjustments are made to recent sales outcomes, the quantified impact of the price rises appears insufficient to account for the level of reduction in ETSA Utilities' actual sales, suggesting that the actual price-related sales impact is greater than has been estimated by ESIPC.

E.4 Customer Numbers

ESIPC's own projected trends in ETSA Utilities' residential customer numbers imply average growth of nearly 1.8% pa. This is higher than the long-term history of customer growth of about 1.0% pa. The ESIPC forecasts appear to overstate likely customer growth rates for South Australia, thereby contributing to an overstated sales forecast.

E.5 Other Issues

ETSA Utilities identified three issues that need to be considered in any re-forecast of sales:

- **A shift in the water heating market, away from electric water heating**. The shift has been evident for some time involving the use of gas and solar electric, and will accelerate when new housing design standards are introduced.
- **Increasing economic pressures upon South Australia's traditional industrial manufacturing sector**. The high Australian dollar, global competition, historic under-investment in plant and equipment and high real estate values all negatively impact on the outlook for this sector and associated electricity sales.
- **The high probability that South Australia is already in the early stages of an unprecedented energy conservation response to global warming**. The range of government, media, educational and community stakeholder energy conservation initiatives is increasing in number and scale, with a material long-term impact on electricity usage per customer. The ESIPC forecast takes account of the known initiatives however other new initiatives are likely including the Solar Cities program and Productivity Commission initiatives on Energy Efficiency.

E.6 Summary

Realistic sales forecasts are critical to ensuring that ETSA Utilities can recover its allowable costs.

ESIPC's re-forecast of energy sales currently being undertaken must appropriately address ETSA Utilities' concerns with the original forecast.

F. Regulated pass-through

F.1 Introduction

ESCOSA has allowed for a number of defined pass-through events within chapter 13 of the Draft Determination however the defined pass-through events do not effectively address issues raised by ETSA Utilities in our Expenditure Submission and subsequent response to the ESCOSA Issues Paper in relation to that submission. These issues relate to:

1. Undergrounding of 66kV Powerlines;
2. Relocation new substations;
3. Retailer of Last Resort responsibilities; and
4. Regulatory Fees.

In its Issues Paper, released in response to ETSA Utilities' Expenditure Submission, ESCOSA proposed that pass-through events should satisfy the criteria that they:

- Are outside of ETSA Utilities' control;
- Are material in their financial impact; and
- Represent an outcome that cannot reasonably be predetermined.

ETSA Utilities considers that each of the events listed above meet ESCOSA's stated criteria and therefore seek that they be incorporated into the 2005 – 2010 Price Determination as either additional pass-through events or within the definitions of the currently proposed pass-through events.

ETSA Utilities also seeks clarification in relation to what ESCOSA might consider are "material" extraordinary events and proposes that the materiality of such events should be judged in relation to the cash impact on ETSA Utilities.

These issues are discussed further within the following sections.

F.2 66kV undergrounding

ETSA Utilities' Expenditure Submission only allowed for erecting new or augmenting existing 66kV powerlines overhead. The Technical Regulator must grant exemptions to the clearance requirements under the Electricity Act 1996 for the proposed level of expenditure to be adequate to complete all the planned 66kV powerline projects contained within our submission.

The Technical Regulator has previously granted exemptions to upgrading existing 66kV lines overhead and we anticipate that some new 66kV powerlines will also be granted an exemption to the Electricity (General) Regulations to enable them to be erected overhead. If the Technical Regulator failed to grant such exemptions, all new or augmented 66kV powerlines would require undergrounding and an additional $120 million in capital funding would be required over the next regulatory period.

We consider that a failure by the Technical Regulator to grant an exemption to erect a 66KV powerline overhead would not currently be classified as a "decision" by a Government body to permit an application for a pass-through under ESCOSA's proposed definitions. On this basis, the defined pass-through events need to include an item that would allow ETSA Utilities

to apply for a pass-through of the additional costs for a undergrounding a 66kV powerline where the Technical Regulator does not provide an exemption after application by ETSA Utilities.

ETSA Utilities is also required by Legislation to submit all new and upgrades to existing 66kV powerlines to the Development Assessment Commission for planning approval. It is conceivable that even where the Technical Regulator has granted an exemption the DAC process will require that the 66kV powerline to be installed underground. This could be via the DAC granting the approval subject to the powerline being installed underground and thereby satisfying the requirements of the current pass through definition "as a decision made by Government body". Alternatively, the undergrounding could be agreed by negotiation with Council, DAC Officers and administratively approved and therefore not meet the proposed definitional requirements of a pass-through. ETSA Utilities considers that where we are to underground a 66kV powerline through either negotiation or by decision we must be allowed to recover the additional costs as a pass-through.

F.3 Relocation of new substations

ETSA Utilities has planned the establishment of 6 new substations within the reset period 2005 to 2010. Given recent experience[36], it is possible that some of these substations will require relocations with the associated additional costs of land acquisition, relocation of existing tenants, site development costs, and extension of cable routes to the substation. The indicative cost of such a relocation is $3 – 4 million per site.

ETSA Utilities is required to submit a development application to the Development Assessment Commission (DAC) to establish a new substation on a greenfield site. We consider that a decision by DAC would constitute a decision by a Government Body and therefore we would be entitled to apply for a pass-through. However, ESCOSA has indicated its preference that ETSA Utilities and the Council(s) concerned negotiate an acceptable outcome to both parties. Once the outcome is agreed the DAC Officers would approve the application administratively.

We consider that this negotiation and joint application would not constitute a "decision" by Government and therefore would not be allowed as a pass-through under the current definitions. If ETSA Utilities were required to pursue a development application without change to accommodate community concerns, to ensure that DAC made a decision that would enable us to apply for a pass-through, then our business relationships with Councils and DAC would deteriorate. This deterioration we consider would ultimately lead to higher costs for customers as the process to achieve the outcome could no longer be negotiated.

[36] A substation proposed at Hope Valley has recently had to be re-situated as a result of resistance from residents and council despite ETSA Utilities' having acquired the land 40+ years ago, prior to residential development, and having installed clear signage indicating that the future use of the site would be as an ETSA Utilities substation.

F.4 Retailer of Last Resort (RLR) obligations

ESCOSA has currently included $1 million per annum for RLR establishment costs. This cost is currently only an estimate and a pass-through should be allowed for a reduction or increase in the establishment costs, once determined.

Further, ETSA Utilities is required by the Electricity Act and associated regulatory instruments to be kept financially neutral in the event of a RLR occurrence. We consider that it would be prudent to allow for the residual costs associated with a RLR event to be permitted as a pass-through as attempting to charge RLR customers additional costs after the RLR event would be impractical and costly.

F.5 Regulatory fees

We are concerned that a change in Regulatory Fees is excluded from being a pass-through event for the next regulatory period given that the new National Energy Regulator (NER) is likely to be established at some stage during that period. The costs and fees associated with the NER are totally unknown as this stage and it is not possible to estimate the fees that ETSA Utilities will be required to pay.

Further, it is noted that Distribution License fees have historically increased at a rate greater than inflation. In the current period, ETSA Utilities has had to contribute an extra $4.7 million above the amount established as the Distribution License fee at the commencement of the period. This represents an amount of approximately $1 million greater than would have been the case if only CPI related adjustments to fees had been made.

F.6 Extraordinary events

ETSA Utilities considers that whether a pass-through event is judged to be material should be considered with respect to the cash impact on ETSA Utilities and not just the annualised cost of the event.

ETSA Utilities establishes its funding at the commencement of each regulatory period for the projected expenditure during that period. Accordingly, funding difficulties can arise in response to an extraordinary event regardless of whether the expenditure is capital or operating in nature.

ETSA Utilities agrees with ESCOSA's proposal not to precisely define the threshold cost for an event to be accepted as a pass-through. However, we believe that there needs to be some guidance in respect to what events would be considered as material by ESCOSA. ETSA Utilities proposes that events which have a cash impact in the order of $1 million or greater should be considered as material.

F.7 Summary

In order to ensure that neither ETSA Utilities nor customers are disadvantaged by the treatment of uncertain events that may or may not occur within the next regulatory period, it is appropriate that such events be treated as pass-throughs.

ESCOSA's currently proposed pass-throughs do not include a number of events that ETSA Utilities' considers clearly satisfy the criteria defined by ESCOSA. On this basis, we seek that the events described above be incorporated into the 2005 – 2010 Price Determination as

either additional pass-through events or within the definitions of the currently proposed pass-through events.

Further, we propose that materiality be more clearly defined by ESCOSA in relation to the "Extraordinary events" pass-through, and recommend that such materiality be judged on the basis of cash impact on ETSA Utilities with an indicative cash impact in the order of $1 million being considered material.

G. Profit Sharing Factor

G.1 Introduction

As part of the revenue control formula detailed in Part B, ESCOSA has proposed the introduction of a profit sharing factor, such that an amount equal to 40% of the previous year's pre-tax profit from the provision of unregulated services which utilise prescribed distribution infrastructure is deducted from the current year's prescribed revenue.

ETSA Utilities believes the proposal represents poor regulatory practice, is without legal support, is poorly defined, and lacks balance. These concerns are discussed further below.

G.2 Poor regulatory practice

ETSA Utilities remains of the view that profit sharing is precluded by clause 7.2 of the EPO. The purpose of this clause was to provide regulatory certainty to the party which purchased the privatised distribution business as to the matters that would be taken into account by the Regulator in the price reset for the subsequent pricing period.

To this end, it is our view that clause 7.2 represents an exhaustive and exclusive list of those matters. The inclusion of a profit sharing factor in this determination, a factor that is not specified in clause 7.2, would therefore constitute an error of law.

The proposed profit sharing mechanism would apply to revenue streams that were in place at the time of privatisation and which are subject to current contracts. This is entirely inappropriate given that such a mechanism could not have been reasonably anticipated at the time of acquisition of the business, or at the time the contracts were formed.

A premium was paid for the business on privatisation based on the valid assumption (confirmed by clause 7.2 of the EPO) that revenues generated from these activities would remain with the business.

To apply the proposed mechanism to these existing contracts is therefore a change that materially affects ETSA Utilities and represents a significant increase in regulatory and sovereign risk. ESCOSA has expressed concern that if existing contracts are excluded, ETSA Utilities will seek to put in place new contracts prior to the next regulatory period commencing in July 2005. This concern is unfounded as no new contracts have been put in place since the Working Conclusion in relation to this matter was issued nor are any being considered over the next six months. However, to overcome ESCOSA's concern, ETSA Utilities proposes that if the profit sharing factor is to apply, although ETSA Utilities argues that it should not, it should only apply to contracts put in place since the issue date of the Working Conclusion on Prescribed and Excluded Services.

G.3 Excessive sharing ratio

Under the proposed scheme, the provision of pre-tax profits to customers provides for an inequitable sharing of gains. Customers receive 40% of overall gains, effectively tax free, whereas ETSA Utilities must still pay company tax on the full profit, including the customers share. This is not a reasonable position to be taken by ESCOSA especially considering that:

- ETSA Utilities is taking the initiative to increase the utilisation of its assets and is subject to the associated business risk;
- such activities help sustain the commercial viability of the organisation and therefore help to protect the long term interests of customers; and
- our withdrawal from the provision of such services would not be in the interests of customers or the economy.

The Draft Determination offers no discussion as to ESCOSA's justification for such an excessive sharing ratio.

G.4 ESCOSA's intention

ETSA Utilities has a good understanding of the types of services that ESCOSA had intended to be captured by this profit sharing factor. This understanding is based on the discussion in Part A of the Draft Determination, together with the Prescribed and Excluded Services Discussion Paper and Working Conclusions Paper, as well as discussions with ESCOSA staff in relation to this topic.

It is our understanding that ESCOSA had intended to capture unregulated and excluded services revenue that ETSA Utilities earned from providing access to prescribed electricity infrastructure. Specifically, the sources of revenue of concern to ESCOSA are:

- pole rental charges for the mounting of street lights on stobie poles;
- pole rental charges for the mounting of mobile phone antennae on stobie poles; and
- pole and duct rental charges for the provision of access to telecommunications carriers.

These services are characterised by the provision of access to prescribed assets (ie. our poles and ducts) at very little incremental cost to ETSA Utilities.

Our reading of Part B shows that only some of these charges are captured by the proposed definitions. The current definitions of the profit sharing factors do not include the excluded services component of this revenue.

In our comments on Part B of ESCOSA's Draft Determination, ETSA Utilities has proposed wording to ensure that the profit sharing factors (Pt, PAt, and PBt) encompass only profits from the provision of unregulated and excluded pole and duct rental services, should ESCOSA continue to pursue such profit sharing.

If, as we understand it, Excluded Services are to be included in the profit sharing arrangements, then a further issue arises which is the interrelationship between the profit sharing mechanism and the assessment of the overall profitability of the Excluded Service group.

We propose that where an Excluded Service is subject to the profit share arrangement then that profit should be excluded from the assessment of the "overall profitability".

G.5 Profit sharing factor summary

ETSA Utilities remains of the opinion that the profit sharing scheme is precluded by the EPO and should be withdrawn. If ESCOSA do not accept ETSA Utilities' advice in relation to this matter, then as a minimum, it must:

- Not introduce the scheme in a retrospective manner;
- Reduce the profit share percentage to a more equitable proportion; and
- Not include any profits subject to the profit sharing scheme in its assessment of the profitability of ETSA Utilities' Excluded Services.

H. Attachments

1. "Valuation of Network Easements – ETSA Utilities, SKM, May 2004

2. "The Equity Beta of an Electricity Distribution Business", Professors Officer and Gray, October 12, 2004

3. "Regulatory precedent in the use of market data in estimation of the equity beta for regulated businesses", NERA, October 2004

4. "Critique of the internal labour escalation factor adopted by ESCOSA for ETSA Utilities", NERA, February 2005 *(confidential)*

5. Non-internal labour cost escalation: a critique of ESCOSA's Draft Determination", NERA, February 2005 *(confidential)*

6. "Review of ESCOSA's analysis of the Draft Determination's financial impact on ETSA Utilities", NERA, February 2005 *(confidential)*

Attachment 1

Valuation of Network Easements – ETSA Utilities

VALUATION REPORT

MAY 2004

- Final
- 17-May-04

Valuation of Network Easements
ETSA Utilities

VALUATION REPORT

MAY 2004

- Final
- 17-May-04

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Contents

Document history and status

Revision	Date issued	Reviewed by	Approved by	Date approved	Revision type
Draft	13th May 2004	J Juchniewicz	D Wells	13th May 2004	
Final	17th May 2004		D Wells	17th May 2004	

Distribution of copies

Revision	Copy no	Quantity	Issued to
Draft		Email	P Turner, Johnson Winter Slattery
		E-mail	P Makinson, ETSA Utilities
Final		E-mail	P Turner, Johnson Winter Slattery
		E-mail	P Makinson, ETSA Utilities

Printed:	11 February 2005
Last saved:	17 May 2004 02:35 PM
File name:	Document2
Author:	D F Wells
Project manager:	D F Wells
Name of organisation:	Johnson Winter & Slattery
Name of project:	Valuation of Network Easements - ETSA Utilities
Name of document:	Valuation Report
Document version:	Final
Project number:	QH59502

1. Executive Summary

By letter dated 24th February 2004, Johnson Winter & Slattery asked SKM to "provide advice in relation to the valuation of easements held by ETSA Utilities as at the 1 July 1999 calculated using an indexed historical cost" and to "perform a valuation of registered easements held by ETSA Utilities as at 1 July 1999".

The scope of the assignment was subsequently increased to include the valuation of licences held by ETSA Utilities as at the 1 July 1999 and to benchmark compensation against the historic value for compensation allowed by the ACCC in their decisions in other jurisdictions.

The valuation is in two parts, compensation and acquisition costs.

Compensation represents payments made to landowners by ETSA Utilities for the granting of registered easements or licences to allow the construction, maintenance and operation of their lines. The compensation value benchmark rates were developed from data available in the recent ACCC revenue resets decisions for SPI PowerNet and Powerlink Queensland and in ElectraNet SA reports to the ACCC as part of their recent revenue reset submissions. The benchmark rates took into account the narrower easement widths for the 66kV and 33kV lines operated by ETSA Utilities.

Acquisition costs are associated with obtaining the easements and licences and include real property survey and preparation of survey plans, valuation by registered valuers of the compensation to be paid to landowners, negotiations with landowners and registration of the agreements in the case of registered easements. Sinclair Knight Merz has obtained and compared the costs of the routine route acquisition activities of recently constructed transmission lines in three different states of Australia and has used this data as a benchmark for this assignment. These benchmark costs were adjusted as appropriate for application to the sub-transmission and distribution lines operated by ETSA Utilities.

The rates for acquisition adopted in this valuation reflect "historic" rates, in that they are based on the practices and statutory requirements that existed at the time the easements and licences were acquired. The rates adopted are not Modern Equivalent Asset (MEA) replacement costs and do not reflect present practices associated with the acquisition of easements and do not include extensive costs for environmental impact assessment, native title considerations and public consultations.

The results of the valuation are shown in Table 1.

Table 1 - Valuation of Easements and Licences

Compensation	$14.4 million
Acquisition	$104.4 million
Total	$118.8 million

SKM considers that the total valuation of $118.8 million is reasonable.

2. Approach to the Assignment

The valuation is in two parts,

- valuation of compensation paid to land owners for the granting of registered easements and licences and
- valuation of the costs associated with the acquisition of easements and licences.

For both compensation and acquisition valuations, historic rates were developed. These rates are not included in the MEA rates that were established for assessing the replacement value of the lines constructed on the easements or routes covered by licences.

The historic values reflect the practices and statutory requirements that existed at the time the easements and licences were acquired. They do not include the now significant costs for environmental assessment, obtaining planning and statutory approvals, public consultation and dealing with native title and heritage issues.

The approach for valuing costs associated with the acquisition of easements and licences involved,

- verification of the database,
- reviewing past practices for easement/licence acquisition and past statutory requirements,
- analysing a recent ETSA Utilities' project for acquiring easements and deducting costs for activities that were not required at the time the easements were obtained,
- benchmarking these costs against an independent SKM assessment based on experience with similar assignments,
- calculation of the historic value.

3. Historic Benchmark Value of Compensation

3.1 Approach

SKM was asked to assess the value of compensation paid to landowners for the granting of easements for ETSA Utilities' lines by benchmarking against the historic values for compensation adopted in other jurisdictions by the ACCC.

The benchmark unit used in this assessment is *$ per hectare of easement*. Use of *a $ per km of easement* was not appropriate because the only consistent data available on historic compensation values are from the most recent revenue reset decisions of the ACCC. These decisions are for transmission utilities that operate lines at voltages from 132kV to 500kV (easement widths 30m to 75m) compared with the ETSA Utilities' sub-transmission and distribution lines (average easement widths approximately 16m). The use of *$ per hectare* as the benchmark unit allows the transmission historic compensation values to be scaled down to appropriate values for the ETSA Utilities' network. Submissions to the ACCC by TransGrid, SPI PowerNet, Powerlink Queensland and ElectraNet SA were analysed.

In the case of Powerlink Qld., SPI PowerNet and TransGrid, the historic values for easements used in this assessment were the values allowed by the ACCC in the most recent revenue reset decisions for each utility. Theses values were obtained using the approach preferred by the ACCC, ie, the historic purchase costs rolled forward at the appropriate Consumer Price Index (CPI).

In the case of ElectraNet SA, the values for compensation used in this assessment were taken from the ElectraNet SA submission to ACCC, Oct 2002, "Historic Easement Compensation Cost based on SPI PowerNet Costs".

SKM has reviewed the ETSA Utilities' records and database and considers that they accurately reflect the ETSA Utilities asset quantities used in the assessment.

3.2 Assessment of benchmark unit rate

Table 2 shows the results of the analysis for Powerlink, SPI PowerNet and TransGrid.

Table 2 – Historic compensation values for other jurisdictions

Utility	Line length(1) (circuit km)	Estimated easement area (ha)	Historic easement value(2) ($m)	Estimated easement unit rate ($/ha)
Powerlink	12 551	35 095	1 14.4	3 260
SPI PowerNet	6 332	21 565	79.7	3 696
TransGrid	12 338	39 904	321	8 044

Notes

(1) Published data in ESAA and utility annual reports.

(2) Values allowed for easement compensation in decisions by the ACCC for utility revenue resets. The valuation of easements followed the approach preferred by the ACCC for the valuation of easements, ie, the historic purchase cost rolled forward as appropriate.

There is reasonable agreement between Powerlink and SPI PowerNet. It was not clear in the TransGrid submission whether their costs included transaction costs or not. In addition a significant proportion of TransGrid lines are located in the relatively high population regions of Newcastle, Sydney and Wollongong. These are considered factors contributing to the higher rate for TransGrid.

ElectraNet SA also made submissions to the ACCC on the value of compensation paid to landowners for their easements as part of submissions for their revenue reset in 2002.

Table 3 shows the estimated easement unit rate per hectare calculated on the same basis as that used in the calculations for Table 2.

Table 3 – Compensation values for ElectraNet SA(3)

Utility	Line length(1) (circuit km)	Estimated easement area (ha)	Assessed historical easement value ($m)	Estimated easement unit rate ($/ha)
ElectraNet SA(4)	5 540	15 462	53.9	3 486
ElectraNet SA(5)	5 540	15 462	27.5	1 779

Notes

(3) ElectraNet SA submission to ACCC, Oct 2002, “Historic Easement Compensation Cost based on SPI PowerNet Costs”.

(4) Assessed historic easement value based on simple prorating with SPI Powernet historic value

(5) Assessed historic easement value based on simple prorating with SPI Powernet historic value with adjustment for differences in land values between South Australia and Victoria.

The approach adopted by ElectraNet SA for their assessment of historic compensation was that recommended by the South Australian Minister for Energy "to include a fair and reasonable value of the easements in the asset base." The approach involved benchmarking against the historic value for SPI PowerNet and adjustment for differences in real estate values between Victoria and South Australia.

It is considered that the appropriate value from the ElectraNet SA assessment for this assignment is $3 486/ha. This recognises that the average real estate values for land occupied by ETSA Utilities' lines would be higher than the average real estate values for ElectraNet SA because of the closer proximity of ETSA Utilities' lines to populated areas. For this assignment it has been assumed that the average real estate values for land occupied by SPI PowerNet and ETSA Utilities lines are equivalent.

3.3 Calculation of historic benchmark compensation.

The calculation of the historic benchmark value for compensation was based on the following,

- a rate of $3 500 per ha for 66kV and 33kV easements,
- a rate of $1 050 per ha (30% of the 66kV rate) for 11kV and 19.1kV easements,
- average easement width of 16 metres for 66kV and 33kV easements and
- average easement width of 10 metres for 11kV and 19.1kV easements.

Table 4 shows the value calculated for easement compensation benchmarked for compensation allowed by the ACCC in its decisions in other jurisdictions.

- **Table 4 – Historic benchmark compensation**

Voltage	Historic benchmark compensation
66kV and 33kV	$11.6 million
11kV and 19.1kV	$2.8 million
Total	$14.4 million

SKM considers that a valuation of $14.4 million is reasonable.

4. Acquisition of Easements and Licences

4.1 Background

This part of the valuation covers two categories,

- costs associated with the acquisition of registered easements and
- costs associated with the acquisition licences.

ETSA utilities acquired licences from landowners as a matter of course for the installation and maintenance of distribution network infrastructure. This was standard practice from the 1950's to the 1980's when easements began to be acquired for 11kV and 19.1kV lines.

Prior to the 1950's the consent/compensation arrangements were handled by informal agreement of which no records currently exist.

The reason for the transition from licences to easements in the late 1980's was that the licences were considered to be subject to a legal impediment, namely that they did not necessarily bind subsequent owners of the land who were not party to the original licence.

In response to that situation the South Australian Government passed Amendment Act N0. 38 of 1988. The effect of this provision was to deem a statutory easement to exist whenever distribution network infrastructure was located on land which was not owned by ETSA Utilities.

In effect, the statutory easement created in 1988 was a legally enforceable way of continuing the effect of the licences and earlier agreements as against subsequent landowners. For this reason "licences" has been adopted as an asset class in Section 4.2.

This valuation includes only those lines that were subject to licences and where records are currently available.

4.2 Easement/Licence Asset Classes

Asset classes were established as follows,

- easements for 66kV and 33kV,
- easements for 11kV and 19.1kV (metro and rural),
- licences for 11kV and 19.1kV (metro and rural) and
- easements for padmount transformers and switching cubicles.

SKM has reviewed the ETSA Utilities' records and database and considers that they accurately reflect the ETSA Utilities asset quantities used in this assessment.

4.3 Asset Class Rates

In establishing the rates to be used in valuing the various asset classes, the practices and statutory requirements that existed at the time the easements and licences were acquired were taken into account. The rates do not include the now significant costs for environmental assessment, obtaining planning and statutory approvals, public consultation and dealing with native title and heritage issues.

Acquisition costs historically include,

a) real property survey,

b) preparation of survey plans,

c) costs associated with valuing the easements,

d) costs associated with independent valuations by land owners where these are accepted by ETSA utilities (not all land owners take up this option),

e) ETSA Utilities' costs associated with negotiations with land owners and

f) easement registration costs.

For licences, items a), d) and f) were not included.

Table 5 shows the rates used for the calculation of the value of acquisition of easements and licences.

Table 5 – Rates for acquisition of easements and licences

Asset Class	Rate[1]
66kV and 33kV easements	$20 000 per easement km
11kV and 19.1kV easements metro	$2 900 per easement
11kV and 19.1kV easements rural	$3 600 per easement
11kV and 19.1kV licences metro	$900 per licence
11kV and 19.1kV licences rural	$1 200 per licence
Easements for padmount transformers and switching cubicles	$300 per easement

Note 1 - Rates adjusted to December 1999 values

Acquisition costs for 66kV and 33kV lines

In determining the appropriate historic benchmark rate for valuing the ETSA Utilities' 66kV and 33kV easements data, the following sources were evaluated,

- SPI PowerNet submissions to the ACCC in relation to their recent revenue reset (2002)
- Powerlink Queensland submissions to the ACCC in relation to their recent revenue reset (2001)
- ETSA Utilities acquisition costs incurred on the Starfish Hill 66kV line project (2002)
- SKM independent assessment of acquisition costs (2002)

Table 6 shows the results of the evaluation.

- **Table 6 – Acquisition rates**

Data source	Rate	Reference date
SPI PowerNet	$10 900 per easement	1997
	$21 800 per easement km	
Powerlink Queensland	$20 000 per easement km	2001
ETSA Utilities' Starfish Hill 66kV line project	$24 800 per easement km	2002
SKM independent assessment	$18 000 per route km	2002
	$24 300 per easement km	

In considering the rates in Table 6 it is noted that,

- ETSA Utilities have a higher proportion of their lines in developed/urban land zones than do SPI PowerNet and Powerlink.
- The Powerlink rate includes environmental, native title and public consultation costs. However this is considered to be offset by Powerlink lines being on average much longer than ETSA Utilities lines and through more open and less densely populated areas.
- The ETSA Utilities' rate based on the Starfish Hill project is not for the total cost for acquisition of the route and does not include costs associated with environmental, native title and public consultation. The rate calculation has been based on actual costs for the Star Fish Hill line (length – 24.6km) as this is the only recent example since the early 1990's of 33kV and 66kV easements registered by ETSA Utilities.
- The ETSA Utilities costs based on Starfish Hill do not include the costs of owner initiated valuations (not all owners choose to do this) which are normally met by the utility. In this case, these costs were covered by the project developer (for a wind farm project) and the costs are conservative.

- The SKM rate is not for the total cost for acquisition of the route and does not include costs associated with environmental, native title and public consultation. The SKM benchmark rate based on the current cost of acquisition including costs associated with environmental, native title and public consultation is $58 400 per easement kilometre.

Based on the above data it is considered that a reasonable historic benchmark rate for acquisition of 66kV and 33kV easements (not including current acquisition costs for environmental studies, native title surveys and negotiations and public consultations) is $20 000 per easement kilometre (June 1999).

Easements for 11kV and 19.1kV

The rate calculation is based on a current cost build approach *per easement* and is GST exclusive. In addition it is based on actual estimated hours and actual fees as applicable. The number and length of 11kV and 19kV line easements reflect easements held at 1 July 1999 and have been sourced directly from the ETSA Utilities Real Estate Branch's Easement Register. The data is considered accurate.

Two *per easement* rates have been provided – one being for metro easements and the other for rural/country easements. The costs associated with a metro easement are less than those for rural/country easements as the survey costs are increased due to travel and accommodation requirements for rural/country projects.

The percentage applied to the break up of metro and rural/country easements (ie 10 percent metro and 90 percent rural/country) has been based on data provided from the ETSA Utilities Network Department's Geographical Information System (GIS).

Licences for 11kV and 19.1kV

The number of licence agreements held at 1 July 1999 have been sourced directly from the Real Estate Branch's Easement Register and the data is considered accurate.

The calculation has been determined on a percentage of the cost build approach of labour costs applied with respect to 11 and 19kV easements. The percentage has been set by ETSA Utilities Real Estate Branch and assumes that costs associated with establishing a licence would require approximately half the labour hours required for establishing an easement. SKM supports this approach.

Easements for padmount transformers and switching cubicles

The number of padmount transformers, switching cubicles and ground level transformer stations held at 28 January 2000 have been sourced directly from Network's Geographical Information System (GIS). The data is considered accurate and the best estimate of numbers as at 1 July 1999.

No compensation is paid to establish these easements but ETSA Utilities has to negotiate the establishment of the easement with the developers. ETSA Utilities that the labour hours applicable today to establish such a registered easement would be in the order of 4.0 hours.

4.4 Valuation of historic acquisition costs

Table 7 shows the valuation for the historic acquisition costs.

- **Table 7 – Valuation of historic acquisition costs**

Asset Class	Valuation
66kV and 33kV easements	$44.1 million
11kV and 19.1kV easements metro	$1.8 million
11kV and 19.1kV easements rural	$20.6 million
11kV and 19.1kV licences metro	$2.7 million
11kV and 19.1kV licences rural	$33.0 million
Easements for padmount transformers and switching cubicles	$2.2 million
Total	$104.4 million

SKM considers that a valuation of $104.4 million is reasonable.

Attachment 2

STEPHEN GRAY (SFG CONSULTING) &

BOB OFFICER

The Equity Beta of an Electricity Distribution Business

DRAFT REPORT PREPARED FOR ETSA UTILITIES

October 12, 2004

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1. EXECUTIVE SUMMARY

We have been retained by ETSA Utilities to conduct some analysis and to comment on the appropriate equity beta to be used in estimating the weighted-average cost of capital of ETSA. Estimates of individual company equity betas are extremely imprecise and do not provide a high degree of reliability. The null hypothesis whenever one is estimating beta is that of the average equity beta of 1.0. Parenthetically, we note that no Australian regulator has used an equity beta less than one for a fully privately-owned electricity distribution business. The estimates set out in the accompanying paper support the conclusion that the appropriate equity beta for the electricity distribution business trading in circumstances similar to ETSA is not less than one. After full consideration of all of the available evidence, we believe that an appropriate estimate of the equity beta is at least one. In particular, the average relevered equity beta of Australian comparable firms has been 1.0 until very recent times, characterized by unusual market circumstances that have had a pronounced effect on the way betas are estimated. Also, the relevered equity beta of the much larger set of U.S. comparable firms is very close to 1.0. Moreover, ETSA's systematic risk is likely to be at least as high as that of other comparables as ETSA has significant operations in rural areas[1].

We have been asked to comment on a number of specific questions, which appear below.

1.1 MARKET DATA

Is the market data available to determine β_e such as to provide a high level of statistical reliability from which to derive β_e?

The standard techniques for estimating market betas produce estimates with large standard errors. Typical confidence intervals are extremely wide. Moreover, estimates can change significantly if a slightly different data period is used or even if a single observation were omitted. In no sense could these estimates be considered to achieve a high level of statistical reliability.

1.2 MARKET SAMPLE

Is the set of listed companies from which market data as to β_e can be produced of a sufficient size and the measurement period sufficiently long as to generate statistically reliable information?

A representative portfolio of five companies might be used to estimate the equity beta of an Australian energy distribution business. This is an extremely small number of comparable firms and although it could be expected to improve the reliability of beta estimates beyond those for individual firms it is unlikely that the estimate will be statistically reliable. Moreover, the majority of these five comparables do not even have returns data (on which

[1] Users of electricity in rural and outer urban areas tend to be associated with resource processing, manufacturing and rural industries. These industries are more exposed to international markets and therefore tend to vary more with business cycles than service oriented industries which occur more commonly in urban areas. This, in turn, may increase the systematic risk of electricity distribution to such users.

the estimates are based) for the full four or five year estimation period. Therefore, a portfolio or average beta will also be statistically unreliable.

To enhance our conclusions with respect to the Australian market we have examined evidence from the U.S. market where the number of listed electricity companies is large compared to Australia. The evidence also supports a β_e of at least 1.0.

1.3 REPRESENTATIVE DATA

Do the four companies that fall within the market data group provide market evidence that is representative of the whole of the market described in clause 6 of Schedule 10 of the EPO?

The current set of listed comparables numbers four (after the delisting of United Energy). These are not the four companies that are most comparable to the electricity distribution market, nor are they the most comparable to ETSA. They are simply the four companies that happen to be listed on the ASX.

1.4 A SINGLE VALUE

Does the market evidence that is available generate a single prevailing value for β_e that represents the whole of the investment market referred to in clause 6 of Schedule 10 such as to be able to be inserted in the WACC formula contained in Schedule 10?

The market evidence does not generate a single prevailing value for the equity beta. However the equity beta is estimated, it must not be considered to be a calculation or measurement – it is an estimate. The standard regression approach does not compute the true equity beta, it merely narrows it down to within some probabilistic range around a point estimate.

1.5 MARKET DATA FOR A SPECIFIC β_E

Is there credible market data for determining an β_e at a value less than 1?

It is not possible to conclude that the available data supports a conclusion that the equity beta of an Australian electricity distribution business is statistically less than one.

1.6 ESTIMATION

In the context of and for the purposes of the application of the WACC model in Schedule 10 of the EPO and assuming that there is no credible market evidence to establish a single value for β_e, that is representative of the whole of the investment market referred to in clause 6 of Schedule 10, what is an appropriate estimation of β_e?

The regulatory consensus is that $\beta e = 1.0$ is an appropriate estimate of the equity beta of an Australian electricity distribution business with a capital structure of 40% equity and 60% debt . In particular, the ACCC has recently examined the available evidence on the equity

beta of electricity transmission and concluded that an appropriate equity beta estimate is 1.0.[2] In the absence of any persuasive statistical evidence suggesting that the appropriate equity beta is significantly different from one, this same value should be retained. Moreover, the average relevered equity beta (relevered or regeared from an asset β) of comparable Australian firms has been βe = 1.0 until very recent times, characterized by unusual market circumstances that have a pronounced effect on the way β's are estimated. Also, the relevered equity beta of the much larger set of U.S. comparable firms is very close to 1.0. For these reasons, we believe that 1.0 remains an appropriate estimate of the equity beta of an Australian electricity distribution business.

[2] See the ACCC's final determinations on South Australian Transmission Network Revenue Cap 2003-2007/8, Tasmanian Transmission Network Revenue Cap 2004-2008/9, Victorian Transmission Network Revenue Cap 2003-2008,

2. OVERVIEW

In the Australian regulatory environment, the regulated firm's revenue requirement is constructed using a building block approach. One important component of the revenue requirement is the return on capital. This often represents more than 40% of the regulated firm's revenue requirement. The return on capital is computed as the product of the regulatory asset base (RAB) and the weighted-average cost of capital (WACC) which depends on the firm's cost of debt and equity capital. Australian regulators have used the Capital Asset Pricing Model (CAPM) to compute the cost of equity capital. The CAPM provides an estimate of the return that investors would require to compensate them for the risk that is involved in holding shares in the firm. In this context, the appropriate measure of risk is the equity beta. Beta essentially measures the relationship between the returns that are generated by the firm and the returns generated by a broadly diversified market portfolio.

3. ESTIMATING EQUITY BETAS

Equity betas cannot be *observed* or *measured*—they must be *estimated*.

The standard method for estimating equity betas is an ordinary least squares (OLS) regression of stock returns on market returns. Most commercial data sources use four or five years of monthly stock returns and monthly returns on a broad stock market index portfolio. The slope coefficient from a standard OLS regression of stock returns on market returns is then used as an estimate of the equity beta.

As with any regression, the estimated coefficient is not a precise calculation, but simply an estimate. The standard statistical (and legitimate) interpretation of the estimated coefficient from any regression is that the true value of this parameter comes from a normal distribution with mean equal to the parameter estimate and standard deviation equal to the standard error of the estimate. That is, the regression approach does not compute the true beta, it merely narrows it down to within some probabilistic range.

The width and range of this depends on how precisely the coefficient can be estimated. It is the standard error of the regression estimate that measures the precision with which it has been estimated. Typically equity beta estimates, computed by regressing stock returns on market returns, have large standard errors. This means that they are imprecisely estimated and cannot be relied upon with any great confidence.

ESCOSA has noted this in their Preliminary Views Paper (2004) where they note that, "beta estimates are also subject to substantial statistical uncertainty" (p. 53) and that, "other regulators have expressed concern about the degree of statistical imprecision with the available beta estimates for the comparable Australian listed entities" (p. 54).

The imprecision of equity beta estimates has also long been recognized in the academic literature and in practice. For example, the Centre for Research in Finance (CRIF) at the Australian Graduate School of Management computes OLS betas as well as Scholes-Williams betas. The Scholes-Williams procedure provides a statistical correction for non-trading. This correction is designed to correct for the fact that a particular stock may trade more or less frequently than the average stock in the index. The AGSM-CRIF Explanatory Notes explain that, "OLS can only be used when the data used satisfies the assumptions which underlie the regression analysis. One assumption, which is of potential importance in the Australian environment, is that the company and index rates of return should be measured contemporaneously; that is, over exactly the same time intervals. Since we are using monthly data, this is equivalent to assuming that all stocks have a trade (establishing the current price) right at the end of each month. While this might be the state of affairs for BHP, it is not so for many of the companies listed by the ASX. In fact, some listed companies exhibit infrequent trading to the point where they do not trade even at regular monthly intervals.

In fact, the problem is even worse than this. Many of the stocks that are included in the index also trade infrequently. Therefore, even if we are trying to estimate the beta of a stock that is large and liquid and trades continuously, there is still a mis-match with the trading frequency of the index. The index likely contains stock prices from its smaller constituents. The CRIF Explanatory Notes also recognizes this:

"This thin trading phenomenon may introduce biases into the OLS estimates. A number of statistical methods exist for estimating beta in the presence of the thin trading phenomena. The CRIF betas are computed using a version of the method first suggested by Scholes and Williams (1977), this technique adjusts for thin trading inherent in both the stock *and* the market index". However, we cannot simply rely on these Scholes-Williams betas for at least three reasons:

1. They tend to be estimated with even less precision than standard OLS betas (i.e., they are designed to correct for non-trading bias, not statistical imprecision);
2. The Scholes-Williams technique is only one of many statistical adjustments to OLS betas that have been proposed (see below); and
3. The Scholes-Williams technique often produces extreme results, at lest relative to standard OLS betas, but there is no consistent relationship between the two. For example, in the most recent CRIF report (March, 2004), the Scholes-Williams beta is no different from the OLS beta for Envestra, 30% higher for Alinta, and 8 times as large for AGL!

Another reputable data source, Bloomberg, provides a different statistical adjustment. The Queensland Competition Authority (QCA) had regard to this Bloomberg Adjustment in its most recent Electricity Distribution Determination (2001, pp. 95-96). "The Authority adjusted betas in accordance with the approach applied by Bloomberg as follows: *Adjusted beta = 0.33 + raw beta * 0.67*". The QCA then recognized that no statistical adjustment will provide a reliable and robust estimate given the nature of the data that are involved. The QCA concludes (p. 96) that, "The difficulties outlined above merely serve to highlight that the calculation of WACC using CAPM to estimate the return on equity involves some degree of imprecision. However, the Authority considers that in applying CAPM in a regulatory setting, regard must be had to the risks of allowing too low a rate of return. Consequently, the Authority has considered adjusted (as well as raw) betas in the assessment of the rate of return for the electricity distribution businesses".

Three substantial pieces of work that document other variations in the way that betas are estimated in the Australian context are The Allen Consulting Group's report for the ACCC (2002), the NERA (2002) response to this report and the research monograph by Brailsford, Faff and Oliver (1997). These sources document more than 20 alternative statistical approaches that have been proposed to estimate equity betas.

Clearly, there is no single consensus approach for estimating equity betas. The very existence of so many alternative approaches is evidence that none are satisfactory, accurate, or robust. This is perfectly consistent with the approach that has been adopted by ESCOSA in the Preliminary Views paper (2004), "while ESCOSA considers there to be sound reasons for relying to the extent possible on objective market evidence when deriving all of the inputs into the cost of capital, it is concerned at the apparent lack of precision with current market evidence" (p. 57)", and that ESCOSA should not depart from the determinations of other Australian regulators "in the absence of convincing market data".

In addition, the ACCC has recently addressed this issue in its Victorian Transmission Revenue decision. After consideration of the presently low values of the estimates of betas for comparable firms, the ACCC noted the statistical unreliability of these estimates and the range of statistical approaches that might be used to estimate equity betas and assessed that an appropriate estimate of the equity beta for electricity transmission is one.

In our view, there is no "convincing market data" that leads to the conclusion that an appropriate estimate of the equity beta is less than the estimate of one that has been used recently by the ACCC and other Australian regulators.

4. THE SIZE OF ESTIMATION ERRORS IN EQUITY BETA ESTIMATES

4.1. OVERVIEW

All Australian regulators recognize that equity betas are estimated with potentially large measurement errors. ESCOSA (2004) notes that beta estimates are "subject to substantial statistical uncertainty" (p. 53). However, not all stakeholders may appreciate just how large these estimation errors can be. In this section, we:

1. Quantify how imprecise beta estimates are;
2. Illustrate how much standard beta estimates vary over time;
3. Show how much beta estimates change if the length of the estimation period changes; and
4. Demonstrate the effect of a small number of outlier observations.
5. Show how much beta estimates can vary with different estimation techniques.

One approach that has been adopted to reduce estimation error is to compute the beta for an industry or group of stocks. We also examine this approach at some length.

4.2. STATISTICAL IMPRECISION IN BETA ESTIMATES

The CRIF Explanatory Notes document provides details about the estimation procedures that have been used in their calculations and some explanation of how to interpret the results that they report. The standard report format includes point estimates for the equity beta using the standard OLS and Scholes-Williams method. Also reported is a one standard error confidence interval around the point estimate. This is reported to allow standard statistical inference to be applied to the estimates.

It is standard statistical practice to compute a 95% confidence interval around estimated coefficients. The proper interpretation then, is that the true value of the parameter that is being estimated is likely to lie within this range. Alternatively, one can test the hypothesis that the true value of the parameter is x, by examining whether x lies within this confidence interval.

If we examine the most recent report from CRIF (and we argue strongly below that there are many reasons to examine a much broader set of data) we can demonstrate that just how imprecise these beta estimates are. Table 1, below, contains point estimates and the upper 95% confidence interval (CI) for four listed comparables.

Table 1: Point Estimates and Confidence Intervals for AGL, Alinta, Envestra and APT.

Company	OLS		Scholes-Williams	
	Beta Estimate	Upper 95% CI	Beta Estimate	Upper 95% CI
AGL	-0.02	0.54	-0.16	1.04
Alinta	0.36	0.98	0.47	1.69
Envestra	0.28	0.78	0.29	1.39
APT	0.33	0.77	0.51	1.49

Source: Risk Measurement Service Beta Report, March 2004, CRIF, AGSM.

The huge width of these confidence intervals illustrates just how imprecise these estimates are. Recall that the Scholes-Williams estimates correct for thin trading in the stocks being examined and in the benchmark index of stocks. For none of the four companies in Table 1 can we reject the hypothesis that the equity beta is equal to one. Of course, for none of them can we reject the hypothesis that the equity beta is zero, either. If the regulator were to set the equity beta to zero i.e. $\beta e = 0.0$, equity investors are assumed to be satisfied with an expected return that is no higher than the risk-free rate (R_f). This is clearly nonsense and some degree of pragmatism and common sense must be applied. That is, although no point within the confidence interval can be statistically rejected, some points are clearly inconsistent with common sense and with the objectives of regulation and can therefore be rejected on this basis. The point here is that the standard statistical confidence intervals are so wide as to provide very limited guidance on the choice of an appropriate beta estimate. Therefore, to choose an appropriate beta estimate, we need to examine other data. This may include an expansion of the period of data being examined, an increase in the number of firms, a method of averaging the beta estimates of comparable firms, or examining other sources of data and including regulatory precedent. All of these possibilities are examined in the remainder of this section.

4.3. TIME VARIATION IN BETA ESTIMATES

To further illustrate the unreliability of beta estimates reported at a particular point in time (such as those reported in Table 1) we demonstrate the time variation in comparable betas over the last 10 years. Figures 1 – 5 contain OLS betas, Scholes-Williams beta estimates and upper 95% confidence intervals reported in the CRIF beta reports over the last ten years for AGL, Alinta, Envestra, United Energy and APT respectively.

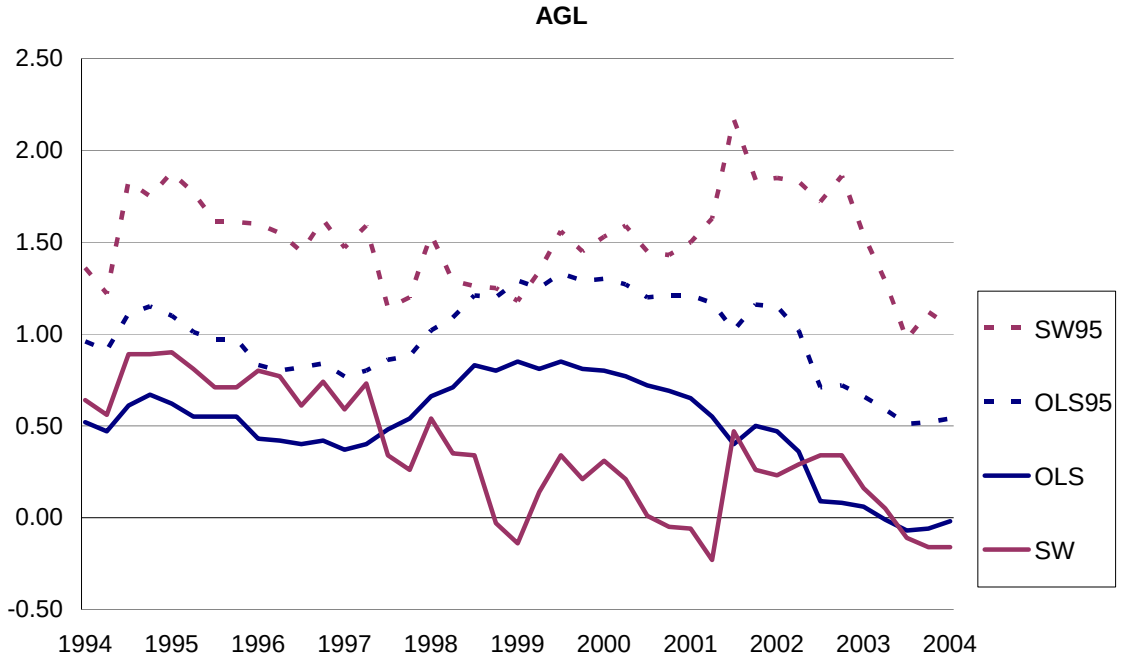


Figure 1: OLS betas, Scholes-Williams beta estimates and upper 95% Confidence Intervals reported in CRIF beta reports for AGL over the last ten years.

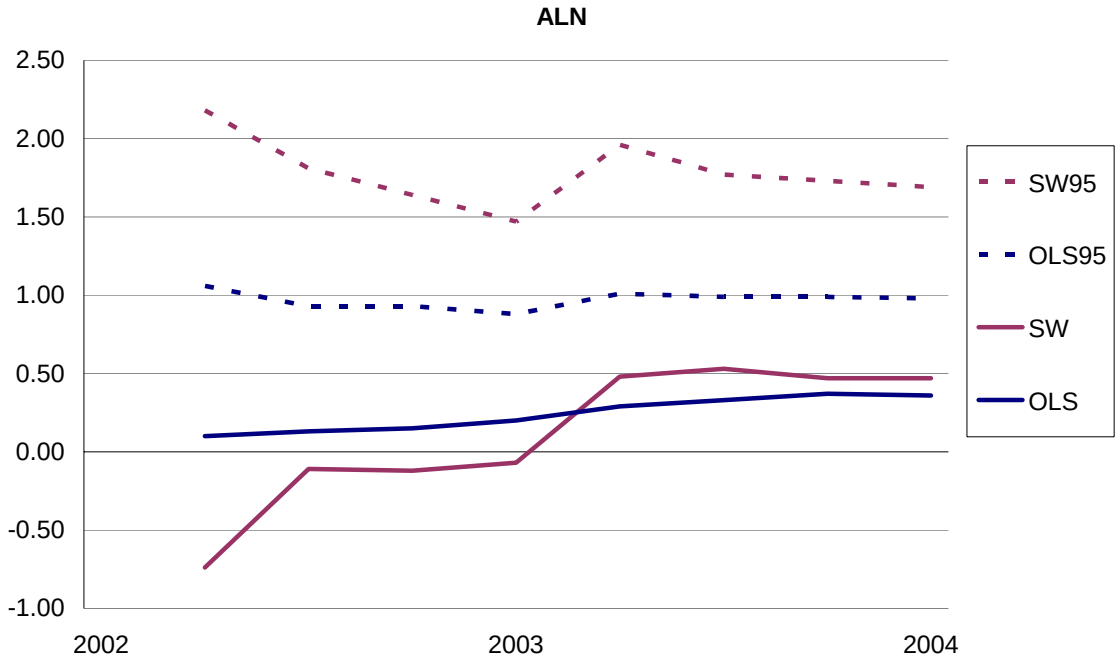


Figure 2: OLS betas, Scholes-Williams beta estimates and upper 95% Confidence Intervals reported in CRIF beta reports for Alinta over the last ten years.

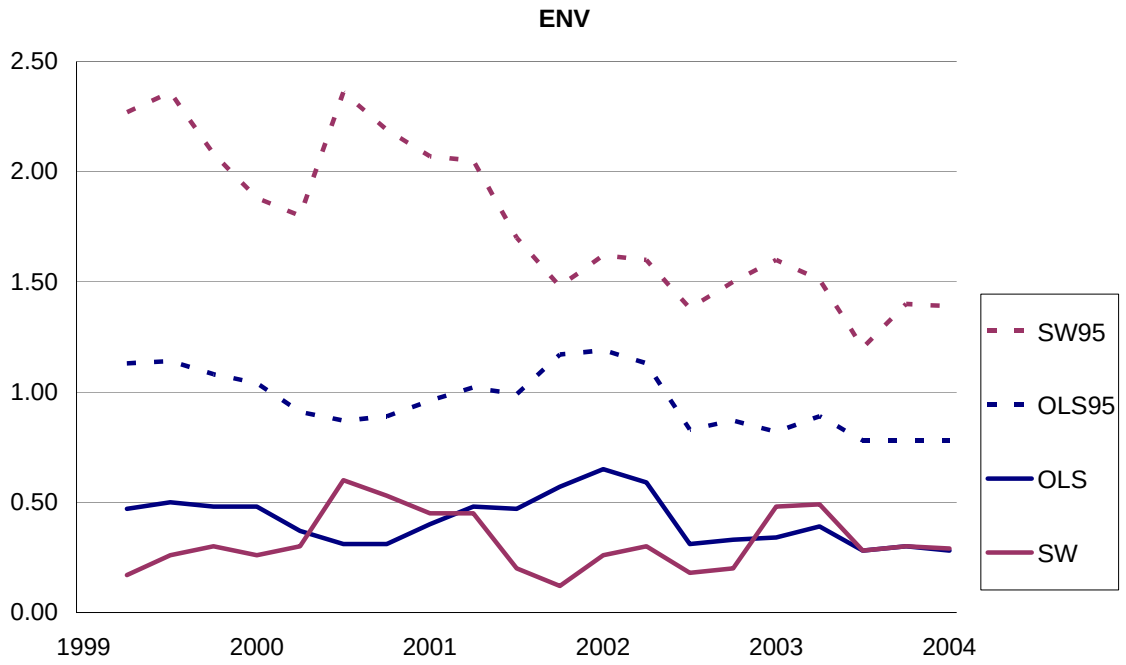


Figure 3: OLS betas, Scholes-Williams beta estimates and upper 95% Confidence Intervals reported in CRIF beta reports for Envestra over the last ten years.

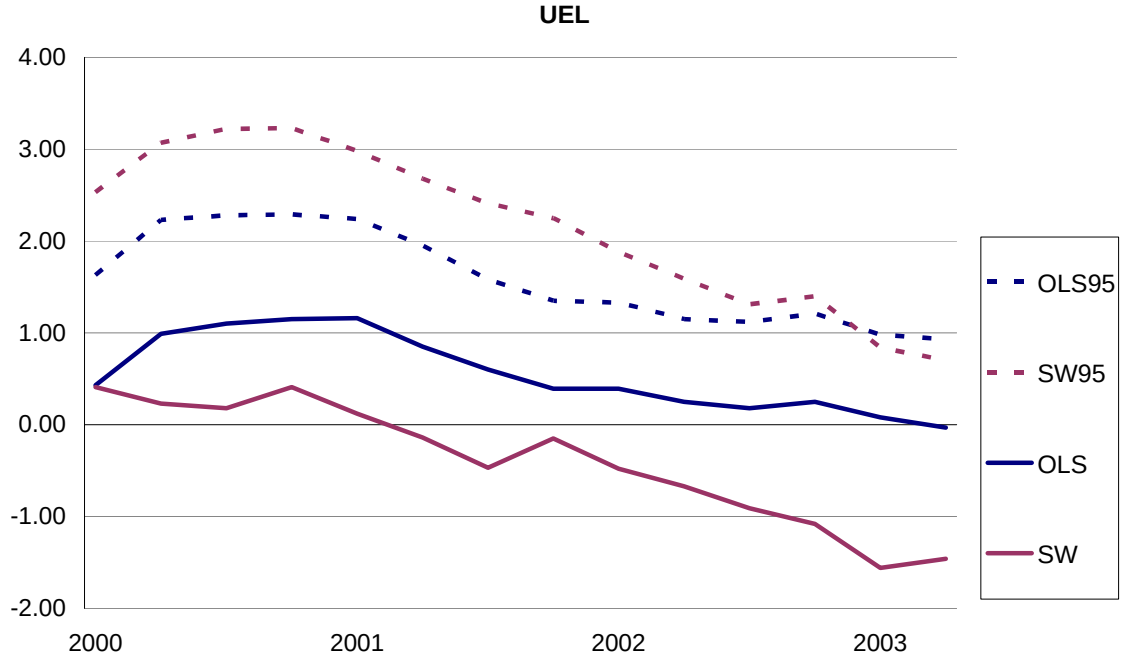


Figure 4: OLS betas, Scholes-Williams beta estimates and upper 95% Confidence Intervals reported in CRIF beta reports for United Energy over the last ten years.

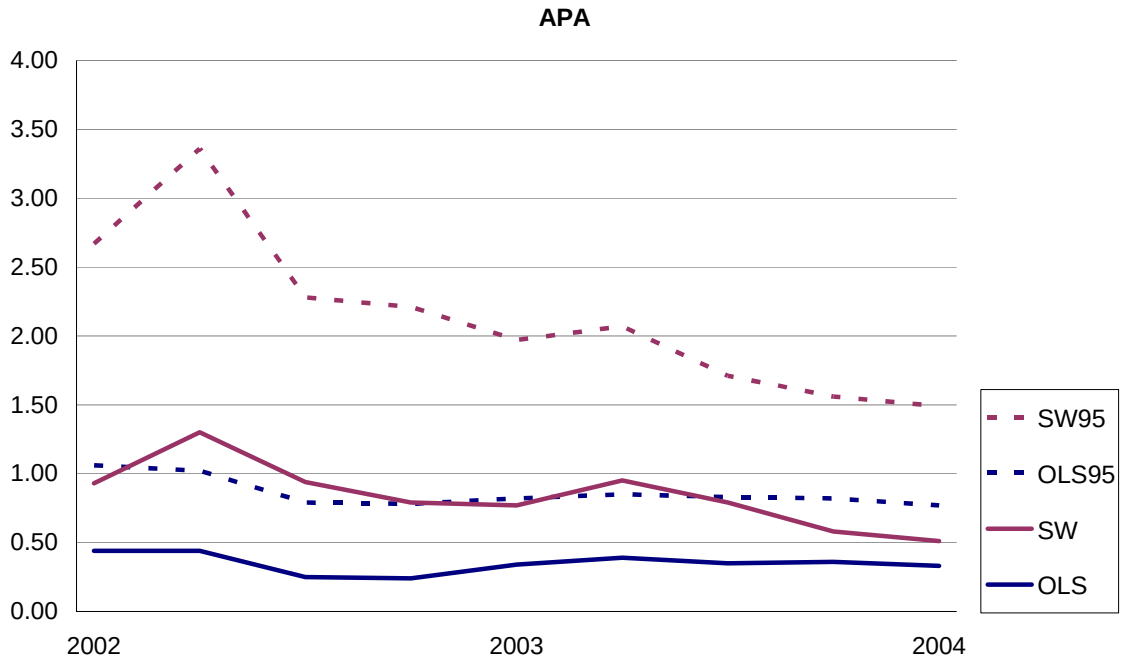


Figure 5: OLS betas, Scholes-Williams beta estimates and upper 95% Confidence Intervals reported in CRIF beta reports for APT over the last ten years.

Clearly, there is significant variation in the time series of beta estimates over the last 10 years. Indeed it is not uncommon for beta estimates to change by more than 0.3 from one quarter to the next, even though the samples differ by only three observations. This further illustrates how fickle and unreliable standard beta estimates are.

A similar picture emerges in where we plot the upper 95% confidence bound for comparable firms over the last 10 years. The variability over time is stark.

This time series variation can either be interpreted as:

1. Real fundamental economic changes in the gas and electricity distribution business and the relationship between these businesses and the broad Australian market; or
2. Evidence of the statistical imprecision and unreliability of the equity beta estimates.

The second interpretation is preferred for two reasons. First, the degree of time series variability in the beta estimates is so large that it cannot possibly be driven by changes in the risk of these businesses—this variability would imply that investors change their required return on these stocks by up to 3% from quarter to quarter. Second, there are several instances where the change from one quarter to the next sees the estimated betas of different firms move in substantially different directions. This is inconsistent with the risk of the energy distribution businesses, generally, having changed—it is more consistent with firm-specific estimation errors.

All of this evidence goes to further reinforce the unreliability of statistical estimates of equity betas.

4.4. CHANGING THE DATA ESTIMATION PERIOD

A number of academic papers have examined the appropriate frequency and length of data that should be used to estimate equity betas. A longer data period provides more observations, but it also increases the likelihood that the nature of the business has changed. If, for example, betas were estimated using 20 years of data, it is likely that the business in the early part of the date period varies considerably from the business in the later part. This may occur due to mergers, acquisitions, spin-offs or even expansion of one division at a faster rate than others. All of these things may change the risk profile of the business and therefore the equity beta.

In addition, the number of data points in a standard beta regression approach can be increased by sampling more frequently. For example, if stock and index returns are sampled weekly, rather than monthly, the number or data points increases fourfold. However, this exacerbates any thin trading problem. For example, if a stock does not trade on a particular day, this represents 20% of the weekly return period but less than 5% monthly return period.

These tradeoffs tend to be balanced by using four or five years of monthly data to estimate equity betas. However, a number of academic and practitioner publications suggest that longer periods (up to 10 years) of data should be used (e.g., Gonedes 1973; Baesel 1974; Alexander and Chervany 1980; Elgers, Hill et al. 1982; Brailsford, Faff et al. 1997). To examine the effect of varying the estimation period, we re-estimated equity betas for a number of comparable firms using 2, 4, and 6 years of monthly returns. AGL is the key comparable firm with sufficient data for this exercise. Recall that CRIF reports an OLS equity beta, based on 4 years of monthly returns, of -0.06. This suggests that AGL shares are a hedge asset, moving inversely to the broad market. However, if we use two years of data instead of four, the beta estimate is 0.22, and if six years of data are used the estimate is 0.40. The corresponding results for Scholes-Williams betas are even more variable.

This is not meant to provide guidance on the length of data period that should be used. It simply serves to further illustrate how fickle and unreliable standard beta estimates can be.

4.5. THE EFFECT OF OUTLIER OBSERVATIONS

Because so few data points are usually used to estimate equity betas (e.g., CRIF betas are based on just 48 return observations) a single outlier can significantly influence the final estimate. In particular, outliers in which the firm's stock moves in a direction opposite to the market can cause a significant reduction in the beta estimate. For example, AGL produced a +5% stock return on the back of positive results announced in September 2001. The fact that this occurred in a month in which the broad market was down 6% (primarily due to terrorist activities in the U.S.) causes the estimated beta to be significantly lower than it would otherwise have been. Also, the AGL stock price fell by 12% in January 2001 amid power rationing and systematic billing problems. These events just happened to occur in a month in which the broad stock market rose.

The questions here are (i) whether these events are one-off chance events or representative of likely future outcomes, and (ii) how much they influence beta estimates.

To examine the sensitivity of beta estimates to a single influential data point, we choose a single observation and ask—how much would the beta estimate change if this observation had occurred in a month in which the market rose instead of falling (or vice versa). Consider September 2001, for example. If AGL had announced positive results and risen 5% in a month in which the market advanced (instead of declining due to terrorist activity) how much would the beta estimate change?

In Table 2, we show how much the standard OLS beta estimate changes, computed with four years of monthly data, if only one outlier observation were changed as described above.

Table 2: Impact of Outliers on OLS Equity Beta Estimates.

Company	OLS Estimate	One Observation Changed OLS Estimate	Two Observations Changed OLS Estimate
AGL	-0.02	0.31	0.55
Alinta	0.36	0.47	0.57
APT	0.28	0.49	0.61
Envestra	0.33	0.43	0.60

The results of this exercise are quite clear. Had one or two stock observations occurred in a different month, the beta estimate would have been radically different. Of course, we are not advocating that betas should be adjusted in this manner and that we should use the estimates in the right-hand column of Table 2. Rather, this exercise is designed to further demonstrate just how tenuous these beta estimates can be.

4.6. SUMMARY

The foregoing analysis demonstrates, in a number of ways, that standard beta estimates are not statistically reliable. If a regulator places primary reliance on a single set of beta estimates from a few comparables, the consequences are:

1. The estimated betas will vary dramatically over time resulting in wild swings in regulatory WACC estimates, thus causing significant regulatory uncertainty;
2. The estimates could be dramatically different if a different data period, frequency, or statistical method had been adopted; and
3. The estimates could be dramatically different had a terrorist attack occurred in August rather than September.

For all these reasons, placing primary reliance on such an imprecisely estimated statistic is clearly inconsistent with fundamental regulatory objectives and principles.

4.7. AVERAGE BETAS AND PORTFOLIO BETAS

In practice, it is widely recognized that beta estimates for individual firms are too imprecise to be relied on with any confidence. A particular concern in this regard is the influence of firm-specific outlier observations as in 4.5 above. To reduce the impact of such outliers, it is common to compute an average beta for an industry group. Often this is done by separately estimating individual betas for each firm and then taking a simple or weighted average. This procedure ignores the correlation between the beta estimates of each firm which means a reliable standard error of the estimate cannot be obtained. Technically, each beta estimate is a random variable (not a precise number) and they are not independent. Therefore, averaging them without consideration of the correlation structure can produce mis-leading estimates and certainly produces a mis-specified and meaningless standard error.

The easiest way to account for these statistical problems is to construct an index of industry returns and then regress those industry returns on market returns. We have performed this exercise by constructing industry index returns in two ways. First, we form a portfolio that consists of all firms

in the Energy Distribution and Retailing GICS industry class[3]. We then compute the portfolio return for each month over the last four years and regress this against market returns. This procedure yields a portfolio beta estimate of 1.02 with a standard error of 0.27. There are two problems with this approach. First, some of the firms in this GICS classification are not close comparables for ETSA. The GICS-based portfolio, for example, include Pacific Hydro and Horizon Energy. Second, there is such variability within the sample and so many extreme returns that the standard error of the portfolio beta estimate is not substantially lower than that of individual beta estimates.

Our second approach was to form a portfolio consisting of closer comparables only. This involves constructing the portfolio returns from the stock returns of AGL, Alinta, APT, Envestra, and United Energy – for the periods over which they were listed. This procedure yields a portfolio beta estimate of 0.24 with standard error of 0.17. However, this portfolio contains a very small number of companies, most of which do not have return data for the full 4-year estimation period. This means that the results are driven, in large part, by AGL. Thus, there are few benefits to be achieved by employing this portfolio grouping technique – we have already addressed the many reasons that the current estimate of AGL's equity beta is statistically unreliable.

4.8. ASSET BETAS AND RELEVERED EQUITY BETAS

The equity beta is a measure of the systematic risk of owning shares in a company. It reflects (i) the systematic risk of the assets of the business, and (ii) the extent to which this risk has been "levered" or "geared" up by debt financing. The first of these components, the systematic risk of the assets, is often referred to as the asset beta, which is denoted as β_a. This simply recognizes that some types of business are riskier than others. The second component, leverage, recognizes that the amount of debt financing that is employed by the firm also affects the risk of owning shares in the firm. This is because debtholders receive a (usually) fixed return prior to any distribution to shareholders. Thus, the residual (after servicing the debt) is available to the shareholders. The risk of this residual return increases with the amount of prior-ranking debt financing. Therefore, two firms in the same industry may have the same fundamental business risk (asset beta) but different equity betas due to differences in leverage. Shareholders in the more levered firm will face higher risk, even though the two firms operate in the same industry.

ESCOSA has recognized this in the Preliminary Views paper (pp. 55-57). In particular, ESCOSA has noted that four of the five Australian comparables on which it relies for empirical evidence have considerably lower leverage than the 60% benchmark gearing level that it assumes for efficiently financed electricity distribution companies. This means that even though these firms may have the same asset beta as the benchmark firm, they will have lower equity betas because their shareholders do not bear the same amount of risk from leverage.

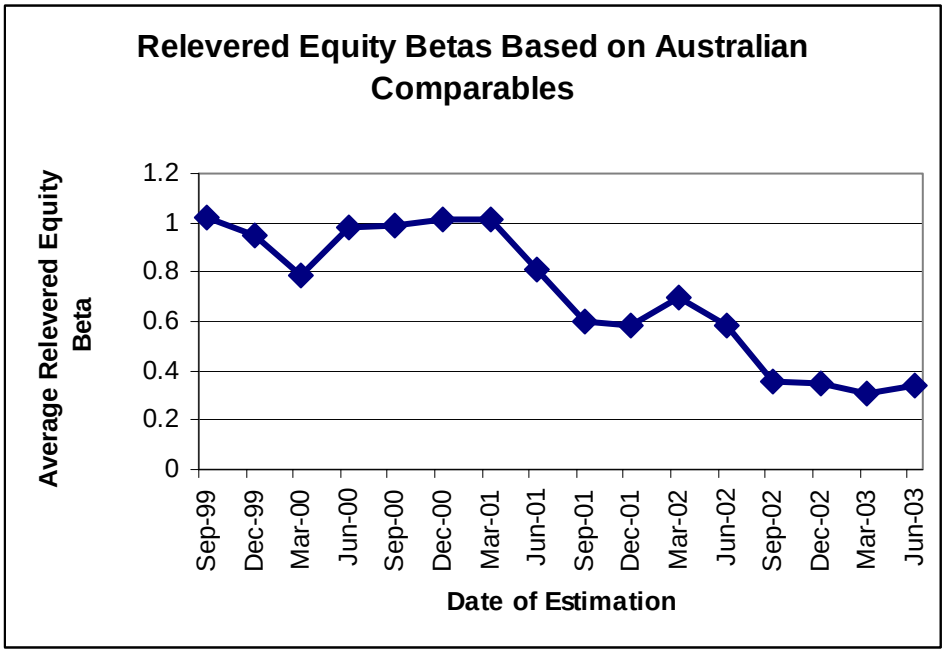
Differences in leverage can be controlled through a procedure known as unlevering and relevering. First, the effects of leverage are removed from the estimated equity betas to produce an estimate of the asset beta. This asset beta is then relevered using the assumed benchmark gearing of 60% to give an estimate of what the equity beta of the comparable firms would have been with 60% debt financing. A number of methods have been proposed for unlevering and relevering. The procedure that has been adopted by ESCOSA is to relate asset and equity betas as

[3] GICS is the Standard and Poors Global Industry Classification Scheme. It is a world standard means of assigning firms to industry portfolios.

$$\beta_a = \beta_e \frac{E}{V} + \beta_d \frac{D}{V}$$

where β_a is the asset beta, β_e is the equity beta, β_d is the debt beta, and E/V and D/V are the proportions of equity and debt financing respectively. The unlevering step is done with the particular comparable firm's capital structure and the relevering step is done with the assumed benchmark gearing. Implementation of this procedure requires an estimate of the debt beta – the risk of owning debt in the firm. Consistent with Australian regulatory practice, ESCOSA examines a range of debt betas from zero (consistent with market practice) to an estimate based on the observed debt margin. We focus on the ESCOSA estimates that are based on a debt beta of zero.

This procedure leads to the average relevered equity betas that are produced in Table 5.2 of the Preliminary Views paper and are reproduced in the figure below.



These results indicate that for the first half of the analysis period, the average relevered equity beta was around one. Between mid-2001 and mid-2002 the estimate declined and has been between 0.3 and 0.4 for the last year or so. Of course, we have already established that the estimation error involved in these estimates is so large that it is difficult to establish any sort of statistical significance. This is only exacerbated by the unlevering and relevering process as estimation error in the debt beta is added to the mix. But if these issues are put aside and the results above are taken at face value, the key question is whether the sharp and sudden decline in beta estimates indicates a dramatic change in the risk of energy distribution or whether it is a temporary statistical aberration.

Two pieces of research would support the conclusion that this is a temporary statistical aberration. First, Annema and Goedhart (2003) examine the impact of the telecom-media-technology (TMT) stock market bubble of 1998-2001. They note (p. 1) that "despite volatility in the market during the 20 years before 1998, industry-specific betas were remarkably stable. But during the bubble, betas

for many industries appeared to decline significantly…these apparent decreases actually reflect the influence of telecom, media, and technology share prices on the indexes during the 1998-2001 bubble and distort the real change in the relative risk borne by companies in other industries." They also note (p. 3) that "recent beta estimates are also more closely in line with pre-1998 values." This is consistent with our analysis above, which indicates that betas estimated using data from only the last two years are substantially higher than those using four years of data.[4]

Annema and Goedhart suggest that these issues can be best handled by re-estimating betas after excluding the 1998-2001 period. This has the effect of substantially increasing the estimates of utility betas to pre-bubble levels. The conclusion from this is that the recent low estimates of beta for energy distribution companies is more an aberration caused by the dramatic and unusual behavior of companies in other industries and that since such unusual behavior is not predicted to re-occur in a four-yearly cycle it should be removed from beta estimates that are to be used to estimate forward-looking estimates of the cost of equity.

In addition, Blume (1975) shows that beta estimates exhibit mean reversion over time. A number of reasons are proposed for this observed phenomenon including the transitory nature of measurement error. Blume also develops an estimation methodology to account for mean reversion. This adjustment has been examined and rejected by ESCOSA. However, the key point here is that Blume documents mean reversion in beta estimates, quite apart from his suggested procedure to correct for it. This is consistent with the notion that the presently low estimates of energy distribution betas are likely to rise in the future.

In summary, it is likely that the low estimates of relevered equity betas for comparable Australian firms will not persist – they are likely to rise in the future. This is consistent with the view taken by ESCOSA in the Preliminary Views paper: Having noted the presently low beta estimates, ESCOSA proposed that an estimate of one should be maintained.

4.9. EVIDENCE FROM FOREIGN COMPARABLES

As a general rule, one cannot directly use as an estimate of a domestic company's beta, the beta of a comparable company from another market or economy. The different composition of the markets is likely to lead to different estimates of beta and the assumptions required to make them equivalent are usually violated. However, given the lack of domestic comparables for energy distribution firms, it would be improper to pay no attention at all to the foreign comparables. Moreover, it may be possible to draw inferences about an appropriate domestic beta from foreign comparables by making adjustments for the differences between the markets.

The most obvious source of foreign comparables is the United States. The table below contains beta estimates for comparable U.S. firms computed by ValueLine. The table also presents equity beta estimates after relevering to the benchmark assumption of 60% debt financing. This has been done for two estimates of debt beta, but the results are insensitive to this choice – the relevered equity betas are very close to 1.0 in both cases.

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[4] In Section 4.4 we report that the OLS beta of AGL is estimated to be -0.06 if the last four years of monthly data are used, but 0.22 if the last two years of monthly data are used and 0.40 if the last six years of monthly data are used. The years 2000-01 contain many extreme market movements (the last part of the stock market bubble and the consequent correction) that give rise to outliers that reduce estimated betas. Note that this point refers to the length of the data period and not the time at which the estimates are made. Here, the point relates to a current beta estimate based on the last two years of data, not an estimate computed two years ago.

Table 3: Beta Estimates from Comparable U.S. Firms.

Industry Name	Number of Firms	Mean Equity Beta	Mean Leverage	Equity Beta Relevered with B_d=0	Equity Beta Relevered with B_d=0.15
Electric Utilities (Central)	25	0.82	52.00%	0.98	0.95
Electric Utilities (East)	30	0.76	49.30%	0.96	0.92
Electric Utilities (West)	15	0.82	48.48%	1.06	1.01
Natural Gas Distribution	31	0.65	46.14%	0.88	0.82
Natural Gas	38	0.87	42.36%	1.25	1.19
Mean		**0.78**		**1.03**	**0.98**

Source: ValueLine. Available at http://pages.stern.nyu.edu/~adamodar/pc/datasets/betas.xls.

Of course, these beta estimates cannot be inserted directly into a domestic Australian version of the CAPM for the reasons we have already discussed. Beta estimates from U.S. comparables reflect the relationship between U.S. firms and the U.S. market portfolio. The Australian domestic CAPM requires an estimate of the relationship between Australian firms and the Australian market portfolio. Whereas these relationships are likely to be similar, they need not be identical due to differences in the composition of the market portfolios and other institutional and regulatory differences.

To determine whether Australian energy distribution firms are likely to be more closely related to the Australian market portfolio, and therefore warrant a higher beta, than their U.S. counterparts, we conducted a simple correlation analysis. In particular, we have computed the correlation between monthly returns of the Australian Gas Distribution Index[5] and those of the Australian market portfolio.[6] This estimate is 0.24 over the most recent 10-year period. The corresponding correlation for the U.S. Electric Utility Index[7] and the U.S. market portfolio[8] is 0.19. We use the Australian gas distribution index for two reasons. First, no electricity distribution index is available. Second, the gas distribution index in Australia includes AGL, APT, Envestra, Alinta, and GasNet, all of which are included in the set of comparables for ETSA.

The conclusion from this analysis is that the U.S. comparable firms have lower correlation with their local market. This indicates that, if anything, it is likely that the appropriate Australian beta estimate is higher than that of the U.S. comparables. Of course, it would be possible to find other indexes or other time periods over which this result may reverse. But this only goes to confirm our earlier point about the statistical unreliability of these types of estimate.

What we can conclude from this analysis is that the U.S. comparable firms provide information that is useful in helping to estimate the appropriate Australian equity beta and that the appropriate relevered equity beta estimate from this data source is 1.0.

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[5] Source: Datastream Australia Gas Distribution Total Return Index.

[6] Source: ASX 200 Total Return Index.

[7] Source: S&P 500 Electric Utilities Total Return Index.

[8] Source: S&P 500 Total Return Index.

5. AUSTRALIAN REGULATORY DETERMINATIONS

Finally, we turn to another source of data – that of other regulatory determinations. These determinations can be thought of as an additional (indirect) form of market data. This is because all regulators are required to give consideration to market data and national and international benchmarks when making their determinations. (The various legislative provisions are outlined in The Appendix.) Thus, the estimate that is produced in the determination is based, at least in part, on a consideration of market data. These determinations are also relevant in that they demonstrate that no other Australian regulator has relied solely on the most recent beta estimates from comparable Australian firms. All regulators have recognised the statistical problems with such estimates.

ESCOSA's Preliminary Views paper already contains a comprehensive review of beta estimates in prior regulatory determinations (p. 57). The results are almost uniform in proposing equity betas at or above one. Indeed every equity beta estimate for fully privatised distribution businesses is at or above one.

In particular, the ACCC has recently addressed this issue in its Victorian Transmission Revenue decision. After consideration of the presently low values of the estimates of betas for comparable firms, the ACCC noted the statistical unreliability of these estimates and the range of statistical approaches that might be used to estimate equity betas and assessed that an appropriate estimate of the equity beta for electricity transmission is one.

These results are relevant insofar as (i) ESCOSA seeks to ensure that regulated returns available in South Australia are not too dissimilar to those available for comparable businesses in other states that the investment of capital may be affected, and (ii) they themselves are based, at least in part, on an assessment of market data.

6. SUMMARY AND CONCLUSIONS

After considering all of the available evidence and having conducted substantial analysis ourselves, we conclude that:

1. It is not possible to conclude that the available data supports a conclusion that the equity beta of an Australian electricity distribution business is statistically less than one.

2. We agree with the approach and conclusions of the ACCC and other Australian regulators in setting the equity beta for electricity networks equal to one, based on a consideration of current market data, all available evidence, and the objectives of the legislation. We concur with the view that an appropriate estimate of the equity beta for an Australian electricity distribution company is one.

3. The average relevered equity beta of Australian comparable firms has been 1.0 until very recent times, characterized by unusual market circumstances that have a pronounced effect on the way betas are estimated. Also, the relevered equity beta of the much larger set of U.S. comparable firms is very close to 1.0.

4. We note that there are at least two arguments in support of the equity beta of ETSA being set above one: (i) ETSA is fully privatised, and has no government backing, express or implied; and (ii) ETSA operates substantially in rural areas. For these reasons, we conclude that the equity beta for ETSA be set at one at least.

APPENDIX 1: AUSTRALIAN REGULATORY FRAMEWORK

In 1995, all Australian governments agreed upon a National Competition Policy. This Policy includes a number of initiatives designed to improve the competitiveness of the national economy. These initiatives included (i) improving living standards for the community at large; (ii) increasing employment; (iii) improving the skills of Australians; (iv) supporting economic and industry growth; and (v) increasing productivity performance through the more efficient use of resources.

Accordingly, independent statutory authorities, such as the Queensland Competition Authority (QCA), Essential Services Commission (ESC), Office of the Tasmanian Energy Regulator (OTTER) and Independent Pricing and Regulatory Tribunal (IPART) were formed to facilitate these initiatives. In doing so, they are required to operate under various pieces of legislation. For example, The National Electricity Code requires that Regulators such as the QCA and OTTER have regard to the following provisions when estimating WACC parameters for an electricity business:

> *"NE Code – 1998, Chapter 6: Network Pricing, Part D: Form and Mechanism of Economic Regulation, Section 6.10.5:*
>
> *5) The* ***Distribution Network Owner's weighted average cost of capital*** *applicable to the relevant* ***network service,*** *having regard to the risk adjusted cash flow rate of return required by investors in commercial enterprises facing similar business risks to those faced by the* ***Distribution Network Owner*** *in the provision of that* network service*; and*
>
> *NE Code – 1998, Chapter 6: Network Pricing, Schedule 6.1: Estimating Weighted Average Cost of Capital, Section 3: Estimation of the Cost of Equity, Sub-section 3.3: Beta:*
>
> *3.3 Beta is a measure of the extent to which the return on a given equity investment moves with the return on the equity market.*
>
> *Beta factor measurements for all listed Australian companies are publicly available. Where beta data is not available (because the* ***Network Owner*** *is not a listed company), it is necessary to estimate a beta factor. This can be done by observing the beta factors of listed companies (in Australia and overseas) which have business risk profiles and capital structures similar to those of Australian* ***Network Owners****."*

There are several other Acts that Regulators commonly operate under in addition to the National Electricity Code. For example, The QCA also operates under *The Queensland Competition Authority Act 1997 (QCA Act 1997). The QCA Act* specifies that when the QCA is computing WACC parameters for a given electricity business, they must have regard to the following maters:

> *"QCA Act – 1997, Part 3 section 26 pp30-1:*
>
> *(d) in relation to the goods or services to which the government monopoly business activity relates—*
> *(i) the cost of providing the goods or services in an efficient way, having regard to relevant interstate and international benchmarks; and*
> *(e) the appropriate rate of return on government agency assets;*

(j) the need for pricing practices not to discourage socially desirable investment or innovation by government agencies;
(m) economic and regional development issues, including employment and investment growth".

The ESC's general regulatory powers are set out in the *Essential Services Commission Act 2001 (ESC Act 2001)* and are applied to the Victorian electricity industry by the *Electricity Industry Act 2000*. When computing WACC parameters for an electricity business, these Acts require the Commission to have regard to the following:

"ESC Act – 2001, Part 3 section 33 pp24-5

33. Price determinations

(3) In making a determination under this section, the Commission must have regard to—
(d) the return on assets in the regulated industry;
(e) any relevant interstate and international benchmarks for prices, costs and return on assets in comparable industries"

The Utilities Commission (UT) regulates certain prices in the Northern Territory's electricity supply industry in accordance with the *Electricity Reform Act 2001* and the *Electricity Networks (Third Party Access) Act 2003*. Accordingly, when computing WACC parameters for electricity businesses, the UC must have regard to the following:

"Northern Territory of Australia Electricity Networks (Third Party Access) Act – 2003, Chapter 6: Network revenue and price caps, Section 68, Part d :

(d) the network provider's cost of capital applicable to the relevant network access service, having regard to the risk-adjusted rate of return required by investors in commercial enterprises facing similar business risks to those faced by the network provider in the provision of that service;

Northern Territory of Australia Electricity Networks (Third Party Access) Act – 2003, Chapter 6: Network revenue and price caps, Section 69, Part 2 :

(2) The revenue cap set by the regulator is to provide a fair and reasonable risk-adjusted rate of return–
(b) the fair and reasonable rate of return is to be consistent with achievement of a commercial return on efficient investment."

The Independent Competition Regulatory Commission (ICRC) operates under the *Independent Competition and Regulatory Commission Act 1997* and the *Utilities Act 2000*. Accordingly, when computing WACC parameters for electricity businesses, the ICRC must have regard to the following:

"Independent Competition and Regulatory Commission Act – 1997, Part 4: Price Directions, Section 20: Directions about Prices (d)

(d) an appropriate rate of return on any investment in the regulated industry."

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Attachment 3

REGULATORY PRECEDENT IN THE USE OF MARKET DATA IN ESTIMATION OF THE EQUITY BETA FOR REGULATED BUSINESSES

A Report for ETSA Utilities

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October 2004
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EXECUTIVE SUMMARY

We have been asked by ETSA Utilities (ETSA) to report on regulatory precedents where regulators have set the compensation for 'beta risk' in a manner that either follows or is consistent with the National Electricity Code (the Code). Chapter 6 of the Code requires regulators set the expected return on equity on the basis of the "rate of return required by investors in a privately-owned company with a risk profile similar to that of the network company". Chapter 6 of the Code also explicitly states that this is a forward-looking concept and permits an estimation of the beta when market data is inadequate.

Difficulties In Estimating Forward-Looking Beta Risk

The equity beta is one parameter in the capital asset pricing model (CAPM) and is defined as the investor's ***expected*** covariance of returns on a stock with returns on the market portfolio as a proportion of the variance in returns on the market portfolio. It is possible to estimate the historical covariance of a stock with the market and to calculate an historical ***proxy*** beta for that stock and that period. However, this should not be confused with estimating the actual historical beta as that value is a function of what investors' expected to happen, not what actually happened.

In our opinion, the Code does not allow regulators to estimate a regulated firm's equity beta solely by reference to historical proxy betas unless the regulator has carefully examined whether there is reason to believe investors will base their expectations on historical proxy betas. In this regard we note that, unlike the most recent trades in the risk-free security, the most recent historical proxy beta estimates are ***not*** evidence of the 'current market conditions'. Rationality requires investors to treat the most recently traded bond yields as the relevant price of debt in the market. However, it would be irrational for investors to base their expectations of future beta risk solely on the most recent historical proxy betas (just as it would be irrational for an investor to base their expectations of the market risk premium on the last year's return on the market).

The only way in which the truly perceived beta risk attached to an equity investment can realistically be estimated with confidence is if one of the following holds true:

1. There is a long time series of the ***historical*** proxy beta data which is representative of all credible ***future*** states of the market and where the historical proxy beta has been relatively stable over that time.

    - Under these very strong conditions all investors would rationally hold the opinion that the historical proxy beta was a good predictor of future systemic risk; or

2. There is sufficient information on investors' (actuarially) expected future earnings to allow an application of the 'dividend growth model' to directly estimate required returns on equity (and implicitly compensation for expected beta risk).

   - This is a less strong set of conditions for accurate estimation of investors' expected beta risk than is 1. Nonetheless, it does require both: a) a large number of comparable listed businesses; and b) a deep market for the services of investment analysts (whose earnings projections can be used as a proxy for investors' expectations of future earnings growth).

In the US, regulators rely almost exclusively on the second approach to estimate the required compensation for beta risk the application of which is set out in detail below. This reflects the fact that there is a lack of confidence in the historical proxy beta as a predictor of equity beta and the US is the one economy with a sufficiently large number of listed regulated businesses and a very deep market for investment analysts to have confidence in the alternative method. (In this regard it is illustrative to note that since 2001 70 US regulated electricity distribution companies have had their return on equity set.) This allows US regulators to directly estimate the current beta risk that is factored into the current equity prices by simply comparing analysts' expectations of future earnings growth with the current equity price. That is, investors' required return is estimated as the discount rate that equates future expected earnings with the current equity price.

Australian Regulatory Precedent

In Australia, and most other countries, there are not a sufficiently large number of listed regulated businesses nor a sufficiently deep market for investment analysis for the US approach to be adopted. The question then becomes whether the first set of conditions described above hold well enough for regulators to rely on historical proxy betas when setting the compensation for beta risk.

We have reviewed all Australian regulatory decisions since 2000 with regard to whether and how they have interpreted historical proxy betas in setting the equity beta. In our opinion, the ACCC and the Victorian ESC are the only Australian regulators that have engaged in more than a cursory examination of historical proxy betas. Other Australian regulators have made passing reference to historical proxy betas when setting the equity beta the relevant analysis has been perfunctory and the primary basis for the decision has been regulatory consistency (both with other regulators and past decisions). For example, the Office of the Tasmanian Energy Regulator[1] and the Independent Competition and Regulatory

[1] Office of the Tasmanian Energy Regulator, ***Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania: Final Report and Proposed Maximum Prices***, September 2003, page 67.

Commission[2] in estimating 'beta risk' relied solely on regulatory precedent rather than directly estimating the investor expectations.

In 2002 the ACCC commissioned an expert report from the Allen Consulting Group (Allens) to examine recent historical proxy betas for regulated gas transmission businesses.[3] The ACCC also undertook internal analysis of recent historical proxy betas - where the scope of comparables was extended to include listed unregulated businesses that were deemed to have similar systemic risks as regulated businesses. This analysis was carried out in the ACCC's 2004 discussion paper and draft decision in relation to the ***Statement of Principles for the Regulation of Electricity Transmission Revenues***. The ACCC also sought and considered a range of submissions on the weight that should be given to historical proxy betas.

The ACCC considered, consistent with the preceding discussion, whether the number of comparable historical proxy betas was sufficient, the period over which observations were available was long enough and the variation in those observations was small enough to allow it to place weight on those observations. Its final conclusion was that despite comparable historical proxy betas from recent periods having average values of around 0.3 that:

> *"…the time period of the market data is not long enough to satisfy the ACCC that market derived equity betas would not systematically under compensate the TNSPs."*

Accordingly, while having regard to the available historical proxy betas the ACCC nonetheless concluded that it was appropriate to set the actual equity beta as equal to 1.0. In our opinion, the ACCC decision to not rely on historical proxy betas, at this time, is appropriate. The Australian financial market does not satisfy the necessary conditions for historical proxy betas to be a good predictor of future systemic risk for regulated businesses, ie, there is insufficient market observations which are unstable over time.

The ESC also performed detailed research of historical proxy betas in its October 2002 ***Review of Gas Access Arrangements***. That analysis included an examination of Australian, UK and US proxy betas for regulated businesses. In doing so the ESC examined a range of technical issues in relation to usefulness of the historical proxy beta estimates – some of which have been relied on by ESCOSA in its preliminary views paper (eg, the ESC's criticism of the use of the Blume adjustment). The ESC noted that sole reliance on recent Australian estimates of historical proxy betas would imply adopting an equity beta of around 0.55. However, the ESC concluded that this would not be appropriate and set a value for the equity beta at 1.0 primarily because:

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[2] ICRC, ***Investigation into prices for electricity distribution services in the ACT: Final Report***, March 2004, page 64.

[3] ***Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities***, A 2002 report for the ACCC by The Allen Consulting Group.

> ***"The Commission remains concerned with the limited amount of Australian capital market evidence that is currently available."*** (page 356)

Both the ACCC and the ESC decisions recognise that it would be an error in theory and fact to assume that investors base their expectations of beta risk on historical ***proxy*** betas.

The ESC and the ACCC also understood that there had recently been a dramatic drop in Australian historical (regulated) proxy equity betas. This fall is reflected in table 5.2 of ESCOSA's preliminary views document where it can be seen that prior to June 2001 the average proxy beta averaged 0.95 while since then it has averaged 0.41 (with most recent values around 0.2). It also happens that there are eight observations both prior to and including June 2001 and eleven observations since June 2001 reported by ESCOSA.

We conclude that the ACCC and the ESC were correct to not lower the estimate of beta to reflect the recent reduction in historical proxy betas. The basis for this view is twofold. First, there is no reason to place greater reliance on more recent historical proxy betas unless you believe that systemic risks associated with regulated businesses are unstable and have changed since June 2001. In fact, the ESC, the ACCC and ESCOSA, have rejected the use of the 'Blume adjustment' when calculating proxy betas for regulated businesses precisely because of the view that systemic risk for regulated businesses is stable over time.

Second, directly observable information on investors' actual discount rates flatly contradicts the most recent historical proxy betas for regulated businesses. For example, we note that the June 2004 historical proxy beta for AGL was –0.04.[4] Given a real risk free rate of 2.8% and AGL's current equity price and earnings information we calculate that this could only truly reflect investors' perceived risk if they expected AGL's real earnings to fall by 3% pa indefinitely. That is, in order for investors to apply a discount rate to AGL's earnings of 2.8% (zero equity beta) and still arrive at an NPV equal to AGL's current share price then expected earnings must be falling 3% p.a. This is simply not credible and is contradicted by publicly available estimates of AGL's earnings growth of around 6% nominal (as reported by Commsec[5]).

In summary, we conclude that of all Australian regulators only the ACCC and the ESC can be regarded as having attempted to carefully analyse historical proxy betas when setting a regulatory equity beta of 1.0.

The ACCC and the ESC have, in our opinion correctly, not reflected recent falls in historic proxy betas in the equity beta they have finally applied and have correctly adopted an estimation process which is consistent with the regulatory pricing models that they administer. Consistent with what was no doubt a materially more robust regulatory

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[4] AGSM Risk Measurement Service

[5] www.commsec.com.au, 24 September 2004

process, no regulator of a fully privatised network has determined an equity beta less than 1.0.

US Regulatory Precedent

In the US there are a large number of listed regulated businesses for which there is a large market for equity analysts. Consequently, US regulators are able to estimate investors' CAPM[6] required rate of return directly using the Dividend Growth Model described above (also described in more detail in section 3 below). The table below summarises all 70 regulatory decisions on the return on equity for US electricity distribution businesses made since the end of 2000.

It is possible to 'back out' the implied equity beta in these decisions on the basis of an assumed MRP and an observed risk-free rate. If we assume an implied market risk premium of 6% then the average implied equity beta over that period is 1.09.[7] It is also true that this is within a very tight range – with the lowest estimate being 0.94 and the highest being 1.26. (In order to bring the average implied equity beta below 1.0 it would be necessary to assume a market risk premium of greater than 6.5%.)

Period		Authorised equity returns (average)	Number of decisions	Average 10y Treasury Security yield‡	Implied equity beta (assuming an MRP of 6%)
2001	1st Quarter	11.38	2	5.05	1.06
	2nd Quarter	10.88	2	5.27	0.94
	3rd Quarter	10.78	8	4.98	0.97
	4th Quarter	11.50	6	4.77	1.12
2001	Full Year	11.09	18	5.02	1.01
2002	1st Quarter	10.87	5	5.08	0.97
	2nd Quarter	11.41	6	5.10	1.05
	3rd Quarter	11.06	4	4.26	1.13
	4th Quarter	11.20	7	4.01	1.20
2002	Full Year	11.16	22	4.61	1.09
2003	1st Quarter	11.47	7	3.92	1.26
	2nd Quarter	11.16	4	3.62	1.26
	3rd Quarter	9.95	5	4.23	0.95
	4th Quarter	11.09	6	4.29	1.13
2003	Full Year	10.97	22	4.02	1.16

[6] If the CAPM describes reality then investors observed required rate of return will be CAPM consistent by definition.

[7] Weighted by the number of decisions in each period.

Period		Authorised equity returns (average)	Number of decisions	Average 10y Treasury Security yield‡	Implied equity beta (assuming an MRP of 6%)
2004	1st Quarter	11.00	3	4.02	1.16
	2nd Quarter	10.40	5	4.60	0.97
2004	Year-to-date	10.63	8	4.31	1.05
Average		11.00	70	4.51	1.09

† The data is an extension of those contained in the, 22 January 2004 Regulatory Research Associates, Inc. entitled ***Major Rate Case Decisions – January 2002 – December 2003 Supplemental Study***.

‡ The Federal Reserve Board, ***Statistics: Releases and Historical Data*** G13 monthly data.

In our opinion, US regulatory precedent is most relevant when attempting to identify regulators who have set compensation for beta risk consistent with ***investors' forward-looking perceived beta risk***. However, the weight given to this will depend on the extent to which, amongst other things, beta risk for regulated US businesses is reflective of beta risk for regulated Australian businesses. In this regard we note that the ESC examined this issue and argued that the regulatory regimes in the US imposed lower risk for regulated businesses and therefore:

> ***"…asset beta estimates for the US firms should be adjusted upwards or accorded less weight when deriving a proxy beta for the Victorian gas distributors."*** (page 343)

We also note that the above regulatory decisions have been made despite US historic equity betas over the same period giving much lower values. In fact, the ESC reported historic proxy betas for US firms of 0.2 and Allen Consulting Group submitted similar calculations for the ACCC. This reiterates our prior conclusions, namely, that historic proxy betas are ***not*** estimates of expected beta risk except under very strict conditions. Where evidence on expected beta risk is observable it very often is wildly different from historic proxy betas over the same period – as evidenced by the above US regulatory decisions and by our previous discussion of AGL.

1 INTRODUCTION

We have been asked by ETSA Utilities (ETSA) to report on regulatory precedent where regulators have set the compensation for 'beta risk' in a manner that either follows or is consistent with the National Electricity Code (the Code).

We note that Chapter 6 of the Code requires regulators to set the expected return on equity on the basis of the "rate of return required by investors in a privately-owned company with a risk profile similar to that of the network company". Chapter 6 of the Code also explicitly states that this is a forward-looking concept and permits an estimation of the beta when market data is inadequate.

The focus of this report is on Australian regulatory precedent. However, we do review US regulatory precedent as this is, to the best of our knowledge, the only country where regulators uniformly attempt to ***directly*** estimate investors' required forward-looking compensation for beta risk.

The remainder of this report is structured as follows:

- Section 2 examines the conceptual and empirical difficulties in estimating beta risk;
- Section 3 examines Australian regulatory precedent; and
- Section 4 examines US regulatory precedent.

2 DIFFICULTY IN ESTIMATING THE EQUITY BETA

The equity beta is one parameter in the capital asset pricing model (CAPM) and is defined as the investor's ***expected*** covariance of returns on a stock with returns on the market portfolio as a proportion of the variance in returns on the market portfolio. It is possible to estimate the historical covariance of a stock with the market and to calculate an historical ***proxy*** beta for that stock and that period. However, this should not be confused with estimating the actual historical beta as that value is a function of what investors' expected to happen not what actually happened.

In our opinion, the Code does not allow regulators to estimate a regulated firm's equity beta solely by reference to historical proxy betas unless the regulator has carefully examined whether there is reason to believe investors will base their expectations on historical proxy betas. In this regard we note that, unlike the most recent trades in the risk-free security, the most recent historical proxy beta estimates are ***not*** evidence of the 'current market conditions'. Rationality requires investors to treat the most recently traded bond yields as the relevant price of debt in the market. However, it would be irrational for investors to base their expectations of future beta risk solely on the most recent historical proxy betas (just as it would be irrational for an investor to base their expectations of the market risk premium on the last year's return on the market).

The only way in which the truly perceived beta risk attached to an equity investment can realistically be estimated with confidence is if one of the following holds true:

1. There is a long time series of the ***historical*** proxy beta data which is representative of all credible ***future*** states of the market and where the historical proxy beta has been relatively stable over that time.

   – Under these very strong conditions all investors would rationally hold the opinion that the historical proxy beta was a good predictor of future systemic risk; or

2. There is sufficient information on investors' (actuarially) expected future earnings to allow an application of the 'dividend growth model' to directly estimate required returns on equity (and implicitly compensation for expected beta risk).

   – This is a less strong set of conditions for accurate estimation of investors' expected beta risk than is 1. Nonetheless, it does require both: a) a large number of comparable listed businesses; and b) a deep market for the services of investment analysts (whose earnings projections can be used as a proxy for investors' expectations of future earnings growth).

In the US, regulators rely almost exclusively on the second approach to estimate the required compensation for beta risk the application of which is set out in detail below. This

reflects the fact that there is a lack of confidence in the historical proxy beta as a predictor of equity beta and the US is the one economy with a sufficiently large number of listed regulated businesses and a very deep market for investment analysts to have confidence in the alternative method. (In this regard it is illustrative to note that since 2001 70 US regulated electricity distribution companies have had their return on equity set.) This allows US regulators to directly estimate the current beta risk that is factored into the current equity prices by simply comparing analysts' expectations of future earnings growth with the current equity price. That is, investors' required return is estimated as the discount rate that equates future expected earnings with the current equity price.

The regulatory approach in the US is illustrated by the Federal Energy Regulatory Commission's (FERC) recent setting of the return on equity for Midwest Independent Transmission System 'Midwest ITO'.[8] In that decision the FERC endorsed the use of a one-step, constant growth discounted cash flow (DCF) model as set forth in Southern California Edison Company (SoCal) decision.[9]

The SoCal model is set out in the Commission's order, and states:

> ***"DCF methodology determines the ROE by summing the dividend yield (with an adjustment for the quarterly payment of dividends) and expected growth rate. The resulting formula is D/P (1+.5g)+g=k, where "D/P" is the dividend yield, "g" is the sustainable growth rate of dividends per share, and "k" is the resulting ROE. The sustainable growth rate is calculated by the formula: g=br+sv, where "b" is the expected retention ratio, "r" is the expected earned rate of ROE, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate."***

This may appear to involve a level of 'circularity' with the expected earnings ("r") being used to set the regulatory rate of return – which will in turn influence expected earnings. However, this is not the case as expected earnings are also capitalised into the current market price of equity ("P").

In our opinion, only when historic proxy betas are very stable for a very long time or the US approach has been accurately implemented can one presume to have estimated the prevailing value of the equity beta in the market for investments.

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8 100 FERC 61, 292 (2002).

9 92 FERC at 61, 262-63.

3 AUSTRALIAN REGULATORY PRECEDENT

Few Australian regulators have attempted to derive proxy values of the equity beta from market data. Those that have attempted to use market data invariably use historical data from listed regulated Australian businesses and other businesses deemed to be 'comparable' to regulated businesses to estimate a proxy beta. In our opinion, the ACCC and the Victorian ESC are the only Australian regulators that have engaged in more than a cursory examination of historical proxy betas. Other Australian regulators have made passing reference to historical proxy betas when setting the equity beta the relevant analysis has been perfunctory and the primary basis for the decision has been regulatory consistency (both with other regulators and past decisions). For example, the Office of the Tasmanian Energy Regulator[10] and the Independent Competition and Regulatory Commission[11] in estimating 'beta risk' relied solely on regulatory precedent rather than directly estimating the investor expectations.

In 2002 the ACCC commissioned an expert report from the Allen Consulting Group (Allens) to examine recent historical proxy betas for regulated gas transmission businesses, which estimated an average historical proxy equity beta of 0.7.[12]

The ACCC also undertook internal analysis of recent historical proxy betas as part of its 2003 review of the Draft Regulatory Principles.[13] The ACCC intended to have a greater reliance on observable market data. It therefore proposed to estimate the equity beta by reference to historical proxy betas of comparable companies. Given the limited number of listed comparable companies, the ACCC proposed to take a conservative approach that set the equity beta by reference to an upper confidence interval of either 95 or 99 per cent.

The internal analysis was conducted on June, September and December 2002 Australian Graduate School of Management (AGSM) data. The scope of comparables included a core sample of listed businesses with regulated income streams and was extended to include listed businesses without regulated incomes, but who were deemed to have similar systemic risks as regulated businesses. The sample included the following businesses:[14]

Core sample	Additional firms
Australian Pipeline Trust	Transurban
Envestra	Macquarie Infrastructure
AlintaGas	Auckland Int. Airport

[10] Office of the Tasmanian Energy Regulator, ***Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania: Final Report and Proposed Maximum Prices***, September 2003, page 67.

[11] ICRC, ***Investigation into prices for electricity distribution services in the ACT: Final Report***, March 2004, page 64.

[12] ***Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities***, A 2002 report for the ACCC by The Allen Consulting Group.

[13] ACCC, ***Discussion Paper Review of the Draft Statement of Principles for the Regulation of Transmission Revenues***, 2003

[14] op. cit. Table 5.1

Australian Gas Company United Energy	Hills Motorway Group

Observed historical market equity betas of these companies were then re-levered so that debt levels were equal to the assumed 60 per cent regulatory debt level. The ACCC internal study suggested that re-levered equity betas were between 0.17 – 0.30 for the core sample and between 0.33 - 0.51 for the combined sample during the three periods observed by the ACCC.

The ACCC also sought submissions from transmission network service providers (TNSP) and other interested parties on the weight that should be given to historical proxy betas. In response to this invitation the ACCC received a number of submissions from TNSPs and their consultants (including from NERA).[15]

The NERA paper highlighted a number of problems with the ACCC's methodology that if corrected would suggest that for the confidence levels discussed by the ACCC an equity beta of at least 1.0 would be required.[16] This, along with a number of other submissions was accepted by the ACCC in its draft decision in relation to the ***Statement of Principles for the Regulation of Electricity Transmission Revenues***. Its final conclusion was that despite comparable historical proxy betas from recent periods having average values of around 0.3 that:

> *"…the time period of the market data is not long enough to satisfy the ACCC that market derived equity betas would not systematically under compensate the TNSPs."*

Accordingly, after having regard to the available historical proxy betas the ACCC concluded that it was appropriate to set the actual equity beta as equal to 1.0. In our opinion, the ACCC decision to not rely on historical proxy betas, at this time, is appropriate. The Australian financial market does not satisfy the necessary conditions for historical proxy betas to be a good predictor of future systemic risk for regulated businesses, ie, there is insufficient market observations which are unstable over time.

The ESC also performed detailed research of historical proxy betas in its October 2002 ***Review of Gas Access Arrangements***. The ESC sample of comparable companies was limited to those businesses for whom the provision of regulated energy infrastructure accounts for a large share of their overall activities. This restricts the ESC to the same group of companies included in the ACCC's core sample.

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[15] NERA, ***Evaluation of the ACCC's proposed approach to statistical estimation of equity betas for TNSPs: A report for TransGrid***, November 2003.

[16] Ibid, page 8.

The ESC's analysis also included an examination of UK and US proxy betas for regulated businesses. Historical proxy betas from sampled overseas business were significantly lower than those derived from Australian firms, but the ESC did not accord these results significant weight.

Using the current Australian financial information the ESC estimated that the historic proxy equity beta for the sample companies was approximately 0.55. However, the ESC noted that sole reliance on recent estimates of historical proxy betas would imply adopting an equity beta substantially lower than that used in other regulatory decisions. The ESC concluded that this would not be appropriate and set a value for the equity beta at 1.0 primarily because:

> ***"The Commission remains concerned with the limited amount of Australian capital market evidence that is currently available."*** (page 356)

In understanding the ACCC's and the ESC's decisions, it is very important that we understand what historical proxy betas are. It would be wrong in fact and theory to interpret historical proxy betas as the observed historical beta. Historical proxy betas are ***not*** observed historical betas. The equity beta as defined in the CAPM reflects the expected covariance of returns on an equity investment and returns on the market portfolio. It is impossible to use historical data to observe what this value was in the past. When we examine historical covariances we are observing ***actual*** covariance rather than ***expected*** covariance. That is, while we may have observed an average equity beta of 0.3 for comparable businesses over the last 4 years we have not observed the equity beta that existed over that period.

That is not to say that historical data from the last four years is necessarily irrelevant to an estimation of today's forward-looking equity beta. How much weight is given to this information in an estimation of the equity beta depends on how much weight investors would give to it. If it was reasonable to assume that investors' expectations of beta were based on the historical proxy beta estimated over the last four years then it would be reasonable to rely solely on the last four years of data. Conversely, if investors gave this very little weight in forming their expectations then it would be appropriate to give it similar weight.

In our opinion there is substantial conceptual and factual evidence to suggest that investors do not base their expectations of the equity beta solely on ***recent historical proxy betas***. The first reason we draw this conclusion is that, when examining systemic risk of ***regulated*** assets, there is no reason to give greater weight to recent proxy beta observations than more distant observations. The second reason is that rational investors will never base their expectations purely on historical proxy betas – and the evidence strongly suggests this is currently the case. The ACCC and ESC were cognisant of both of these reasons in not giving significant weight to recent historical proxy betas.

3.1 Significant Weight Should be Given to All Proxy Beta Observations

There is little or no conceptual reason for a regulator to place greater emphasis on ***recent*** historical proxy betas than on more distant historical proxy betas. The only reason to place more emphasis on recent observations would be if recent observations were considered more likely to reflect the future systemic risks associated with investments in regulated assets. While this may be a reasonable assumption for unregulated businesses where the dynamic nature of the market they operate in is changing over time this is not the case for regulated businesses.

This fact was recognised by ESCOSA in its preliminary views paper,[17] where the use of the Blume adjustment when calculating historical proxy betas was rejected. In that document ESCOSA agreed with the ESC that it was appropriate to assume that the systemic risks associated with regulated assets are stable over-time and that, therefore, it was inappropriate to adopt the Blume adjustment (which implicitly assumes that equity betas are not stable but mean revert to 1.0). Applying this logic consistently suggests that the same weight should be given to all historical proxy betas – irrespective of the time period over which they were estimated.

Table 5.2 in the ESCOSA preliminary views paper reports the mean of historical proxy equity beta calculations for listed regulated Australian businesses since September 1999. The average of all the observations reported in that table is 0.631. However, there is significant variation with the observations ranging from 0.20 to 1.02. Moreover, for the first two years of reported data the historical proxy beta averaged 0.95 while for the next 3 years it has averaged 0.41. Without evidence to suggest that the systemic risks associated with investing in a regulated business have changed over the last five years then there is little reason to place greater emphasis on one of these estimates over the other.

In fact, when the distribution of these estimates is examined it is clear that there are very few observations around the mean with most observations either around 1.0 or around 0.4. This suggests that considerable caution should be exercised in relying on the mean of these - as the distribution does not appear to be normally distributed around the mean. That is, if an investor relied solely on historical proxy betas in forming an expectation of actual betas they would not conclude with any confidence that the mean of the available data will reflect future covariance.

3.2 Current Expectations Inconsistent With Recent Proxy Betas

The above discussion explained why there is little or no reason to give greater weight to more recent observations of historical proxy betas. However, it is also the case that direct evidence of investors' ***actual*** expectations suggests a value for the equity beta materially

[17] Electricity Distribution Price Review: Return On Assets Preliminary Views, page 55.

higher than recent observations. That is, what evidence is available suggests that recent historical proxy betas are underestimates of the true beta expectation held by investors.

Inventors' forward-looking expectations of the equity beta on a stock can be directly measured using discounted cash-flow analysis provided that the researcher can estimate investors' expectations concerning average dividend growth and the market risk premium. This can then be compared with historical proxy betas to 'check' the reasonableness of those proxies for forward-looking expectations. For example, the most recent AGSM historical proxy beta for AGL is –0.04. If this accurately reflects investors' expectations of AGL's future covariance with the market then investors would apply a discount rate of less than the risk free rate in order to value future returns from AGL's equity. Given that we know AGL's current price per share and earnings per share this implies a growth rate in AGL's future earnings. That is, for any assumed equity beta and market risk premium there is an implied growth rate in earnings per share (given we know current share prices and current earnings per share).

We can perform this analysis crudely for AGL based on a current price to earnings ratio of 16.60 compared to the average for the All Ordinaries of 16.03.[18] Thus, on the basis of current earnings, AGL is valued in a near identical manner to the average of all other firms on in the All Ordinaries (suggesting, ceterus paribus, an equity beta of 1.0). However, in order for the current price to earnings ratios to be consistent with an equity beta of –0.04 then the expected growth in AGL's earnings must be less than the average for other firms. In fact, in order to be consistent with a zero equity beta (ie, investors using a discount rate equal to the current real risk free rate of 2.8%) it would be necessary for investors to expect real earnings per share to decline by 3.0% p.a. indefinitely into the future.

Commsec reports earnings per share. These forecasts are for 6% nominal growth over the next two years. This evidence on expected earnings growth (and current equity prices and earnings) strongly suggests that investors are using a discount rate materially in excess of the discount rate implied by the most recent historical proxy beta for AGL. That is, the historical proxy beta is not an accurate reflection of the current market perceptions of beta risk. In fact, a 6% nominal growth rate on current earnings per share in perpetuity would, at current inflation rates, imply an equity beta in excess of 1.0 (assuming a market risk premium of 6%). While this analysis is very crude, it does highlight the important fact that recent proxy betas cannot simply be assumed to reflect actually perceived beta risk.

[18] Commsec 24/09/2004

4 US REGULATORY PRECEDENT

In the US there are a large number of listed regulated businesses for which there is a large market in equity analysis. Consequently, US regulators are able to estimate investors' CAPM[19] required rate of return directly using the approach described above. There is a large database of all US regulatory decisions on the cost of equity made by state regulators. The below table summarises all 70 decisions for electricity distribution businesses made since the end of 2000.

It is possible to 'back out' the implied equity beta in these decisions on the basis of an assumed MRP and an observed risk-free rate. If we assume an implied market risk premium of 6% then the average implied equity beta over that period is 1.09.[20] It is also true that this is within a very tight range – with the lowest estimate being 0.94 and the highest being 1.26. In order to bring the implied equity beta below 1.0 it would be necessary to assume a market risk premium of greater than 6.5%.

Period		Authorised equity returns (average)	Number of decisions	Average 10y Treasury Security yield‡	Implied equity beta (assuming an MRP of 6%)
2001	1st Quarter	11.38	2	5.05	1.06
	2nd Quarter	10.88	2	5.27	0.94
	3rd Quarter	10.78	8	4.98	0.97
	4th Quarter	11.50	6	4.77	1.12
2001	Full Year	11.09	18	5.02	1.01
2002	1st Quarter	10.87	5	5.08	0.97
	2nd Quarter	11.41	6	5.10	1.05
	3rd Quarter	11.06	4	4.26	1.13
	4th Quarter	11.20	7	4.01	1.20
2002	Full Year	11.16	22	4.61	1.09
2003	1st Quarter	11.47	7	3.92	1.26
	2nd Quarter	11.16	4	3.62	1.26
	3rd Quarter	9.95	5	4.23	0.95
	4th Quarter	11.09	6	4.29	1.13
2003	Full Year	10.97	22	4.02	1.16
2004	1st Quarter	11.00	3	4.02	1.16
	2nd Quarter	10.40	5	4.60	0.97
2004	Year-to-date	10.63	8	4.31	1.05
Average		11.00	70	4.51	1.09

[19] If the CAPM describes reality then investors observed required rate of return will be CAPM consistent by definition.

[20] Weighted by the number of decisions in each period.

† The data is an extension of those contained in the, 22 January 2004 Regulatory Research Associates, Inc. entitled ***Major Rate Case Decisions – January 2002 – December 2003 Supplemental Study***.

‡ The Federal Reserve Board, ***Statistics: Releases and Historical Data*** G13 monthly data.

In our opinion, US regulatory precedent is most relevant when attempting to identify regulators who have set compensation for beta risk consistent with ***current market conditions***. However, the weight given to this will depend on the extent to which, amongst other things, beta risk for regulated US businesses is reflective of beta risk for regulated Australian businesses. In this regard we note that the ESC examined this issue and argued that:

> ***"…asset beta estimates for the US firms should be adjusted upwards or accorded less weight when deriving a proxy beta for the Victorian gas distributors."*** (page 343)

We also note that the above regulatory decisions have been made despite US historic equity betas over the same period giving much lower values. In fact, the ESC reported historic proxy betas for US firms or 0.2 and Allen Consulting Group submitted similar calculations for the ACCC.

This reflects the fact that US regulators place practically zero weight on recent proxy beta estimates. It also reiterates our prior conclusions, namely, that historic proxy betas are ***not*** estimates of expected beta risk except under very strict conditions. Where evidence on expected beta risk is observable it very often is wildly different from historic proxy betas over the same period – as evidenced by the above US regulatory decisions.