EnergyAustralia™

ACCC Draft Decision
Service Standard Guidelines

Statement of Principles for the regulation of Transmission Revenues

July 2003

This is a copy of EnergyAustralia's submission to the ACCC relating to its Draft Decision on Service Standards submitted in July 2003. It is included as an attachment to EnergyAustralia's Revenue Reset submission because the ACCC has indicated that a revised regime of financial rewards/penalties is likely to apply to TNSP service standards during the next regulatory period

Introduction

This submission is in response to the ACCC Draft Decision “Statement of Principles for the Regulation of Transmission Revenues – Service Standard Guidelines” dated May 2003.

EnergyAustralia supports the objectives of the ACCC Service Standard review and appreciates the need to provide a mechanism to ensure that service standards are maintained and to provide incentives to improve service standards.

EnergyAustralia believes that TNSPs should be rewarded for improving service standards and should be penalised only if performance falls below acceptable standards.

Given the substantial differences between the networks of the different TNSPs and the diversity and complexity of their operating environments EnergyAustralia believes that performance targets should be set by the use of actual, performance outcomes relating to individual service providers. The use of industry benchmarks would be inappropriate for EnergyAustralia, given the substantial differences between its network and other industry participants.

The design of the incentive scheme should provide symmetric financial consequences. That is:

$$(Upside\ probability)*(Upside\ reward) \cong (Downside\ probability)*(Downside\ penalty)$$

If this relationship were not to hold true, the incentive mechanism would lead to a systematic under or over compensation and distortion of the Determination. Given the asymmetry between the upside and downside probabilities, (a decrease in performance is much easier to achieve than an improvement in performance), the design of the scheme should provide for asymmetric caps , collars and ramping factors.

For the incentive mechanism to induce appropriate changes to business activity:

$$(Upside\ probability)*(Upside\ reward) \geq Operational\ cost\ to\ improve\ performance$$
and
$$(Downside\ probability)*(Downside\ penalty) \geq Operational\ saving\ by\ reduced\ performance$$

The present 1% level of incentive/penalty is sufficient to influence operating decisions. However it is not at a level where it would influence decisions on capital expenditure. It should be noted that the selection of appropriate caps and collars are of equal importance to the target measures. Use of an appropriate dead-band is also considered necessary.

It is apparent that historical performance data is not available and studies of internal processes have not been used to inform the choice of the incentive structure. In the absence of such analysis, it is appropriate for the ACCC to exercise prudence in limiting the impact of the incentive scheme, until greater experience is obtained.

Proposed Performance Measures for EnergyAustralia’s Transmission Network

The nature of EnergyAustralia’s system means that many of the measures (such as Transmission constraints) applied to other TNSPs are inappropriate. Whilst EnergyAustralia’s network predominantly delivers energy to its customers, its operation in parallel with the transmission network results in it conveying a portion of the “through” flow between generators and other distributors. The nature and magnitude of the through flows are such that EnergyAustralia’s network does not constrain market operations. EnergyAustralia thus strongly supports the draft decision that the loss of supply frequency index and transmission constraints are not appropriate for EnergyAustralia.

There are still some issues with respect to the immediate implementation of incentives linked to the two measures (Transmission Circuit Availability and Average Outage Duration) which have been identified as being applicable to EnergyAustralia.

SKM indicated in their discussion paper that existing performance measures were not considered suitable for implementation of service standards due to the lack of appropriate data. They suggested collection of a consistent set of data for a 3-5 years period was appropriate to establish performance objectives. Appendix B of the draft decision indicates that the application of the availability measure to EnergyAustralia should be phased in because of the lack of historical data. This recommendation does not appear to be consistent with Appendix A, which proposes a circuit availability target of 95.5 minutes from Year 1.

Availability Measure

EnergyAustralia has only collected availability performance data since 2000/01 using a manual process. The data available relates to transmission feeders only and does not include statistics for other transmission equipment such as transformers and reactive plant. The recommended target of 95.5 minutes in the draft decision was based on a single year's data (2000/01) and includes only transmission feeders. Future Transmission Availability performance is expected to differ from the 2000/01 data due to:

- the inclusion of transformers and reactive plant, in accordance with the proposed standard definition and

- the inclusion of significant lengths of new 132kV lines and other equipment, resulting from the re-classification of some assets from distribution to transmission during the period of the current determination.

EnergyAustralia considers that proposed changes to both the extent of the transmission system and the definition of availability will make the proposed performance target of 95.5 minutes invalid.

It is proposed that at least three years data using the standard definition of availability should be collected before availability targets are established. EnergyAustralia would propose that availability targets be negotiated no sooner than the second half of the forthcoming determination period (2004-9), following the collection of at least three years of pertinent data.

Significant volatility in availability performance is expected in 2003/04 as a result of an increase in the number and duration of planned outages required to carry out EnergyAustralia's capital program. Further volatility in future years is also likely as a result of the extended repair times required for underground cables, which comprise a significant proportion of EnergyAustralia's transmission assets. Whilst it is proposed to address the issue of extended repair times by capping the impact of a single event, it may also be necessary to establish an appropriate deadband for availability. The extent of this deadband could only be assessed once several years of consistent performance data is collected.

Outage Duration Measure

EnergyAustralia's second performance measure is outage duration. It is noted that no target for this measure has been set in the draft decision, but rather it has been noted in Appendix B that this measure has not been applied due to the volatility of data and the limited control possible.

EnergyAustralia appreciates the need to consider more than one performance measure, however we are concerned that the average restoration time is not a particularly appropriate performance measure for the following reasons:

- The restoration time for equipment will generally not impact on customer outcomes, due to the inherent high level of security in the design of the system.

- The inherent repair times of EnergyAustralia equipment, particularly underground oil and gas pressure cables, is significant (weeks or months) and may vary significantly between cable types. Cable repair times are much more significant to EnergyAustralia than other TNSP's due to the large amount of cable in EnergyAustralia's system. As indicated in Appendix B, there is limited scope to control or reduce repair times through operational measures. Rather, a noticeable decrease in the repair times on such cable systems could only be effected by changing from pressure type to solid dielectric cables. This would require large capital investments which are not the objective of the present incentive mechanism.

- The long repair times associated with some cable types may potentially result in a single failure resulting in a significant variation in the Outage Duration Measure. (indicated in Appendix B)

Given the above factors, it is proposed that Outage Duration should not be adopted as a performance measure for EnergyAustralia during the next determination period.

Should the ACCC wish to further investigate the use of outage duration as a performance measure for EnergyAustralia, it is suggested that data be collected and analysed over the next five years to allow an informed investigation of whether and how this measure could be equitably applied to EnergyAustralia.

Application of measures

EnergyAustralia propose to adopt the following processes and definitions to compile future performance measures.

It is proposed that infrastructure reported in the performance measures should comprise:

- transmission lines (including both cables and overhead lines); and

- transformers and reactive plant at transmission exit points with primary voltages of 66kV or above

Primary equipment included within this definition includes substantial quantities of self contained pressure cables. Jointing and repair times for these circuits may be weeks or even months. Consequently, an extended outage of a single circuit could significantly impact the overall availability measure and result in significant volatility from year to year. To reduce such distortions, it is proposed that the maximum impact of any single event be capped at 7 days.

EnergyAustralia considers that cable damage resulting from actions of a third party in circumstances where cable locations are accurately recorded should be considered a force majeure event and excluded from the recorded measures. It would be inequitable to penalise EnergyAustralia for actions of a third party who may negligently damage cables.

It is also proposed to exclude both planned and unplanned outages initiated by third parties, including EnergyAustralia, in fulfilling its role as a DNSP.

General Comments

Definition of Force Majeure

The present definition of circuit availability includes "extreme" events but excludes force majeure. This is somewhat contradictory. The proposed definition of force majeure will enable a year to year comparison of performance within a TNSP, provided the reporting TNSP adopts a consistent approach. The present definition of force majeure is not sufficiently clear to ensure consistency of reporting between TNSPs. A more precise definition would be required before benchmarking could be applied between organisations.

Random Variations in Performance

EnergyAustralia would expect that there will be significant variation of its performance from year to year. Such variations could occur as a result of random variations in weather or operational issues such as the need for extended outages for repairs or to facilitate capital works. Such volatility is also likely to impact on other TNSPs.

The need for a mechanism to account for such factors was recognised in the proposed methodology through a deadband of appropriate width. Other strategies such as the use of a rolling average of results over several years would be an alternative means of reducing the influence of random events.

Further performance data, to inform the application and setting of deadbands is necessary before the implications of the proposed targets can be fully assessed.

Attachment 11

NECG Report on the Weighted Average Cost of Capital (WACC)

September 2003

Weighted average cost of capital for EnergyAustralia

Submission to ACCC by the Network Economics Consulting Group

September 2003

Contents

1 Introduction

EnergyAustralia has asked the Network Economics Consulting Group (NECG) to prepare a report for the Australian Competition and Consumer Commission (ACCC) on the appropriate weighted average cost of capital it should be allowed to earn on its regulated electricity transmission assets.

In this report, we have estimated a weighted average cost of capital (WACC) for EnergyAustralia, adopting parameter values that we believe are appropriate. Our approach is consistent with the ACCC's approach, with the WACC for EnergyAustralia developed using the Capital Asset Pricing Model (CAPM) and expressed in nominal terms as a "vanilla" WACC.

In the assessment of the appropriate WACC for EnergyAustralia, we have not included any allowance for asymmetric risk. It is not thought that the asymmetric risk is an issue for the WACC per se but should be comprehended in the context of the cash flow modelling underlying a price setting process. However, it is vital that the regulatory framework should allow for asymmetric events providing the regulated business can appropriately quantify the potential impact. EnergyAustralia has addressed this issue in its submission.

This report is structured as follows:

- section 2 assesses the appropriate proxy for the risk free rate;
- section 3 considers the appropriate market risk premium;
- section 4 assesses capital structure and the cost of debt;
- section 5 considers systematic risk;
- section 6 assesses the appropriate value of gamma; and
- section 7 sets out our WACC estimate.

Conclusion

We estimate that as of 1 September 2003 the vanilla WACC for EnergyAustralia is 8.97%. This includes the following components:

- risk-free rate based on the 10-day average of the 10-year Commonwealth bonds of 5.55%;
- a market risk premium (MRP) of 6.0%;
- an asset beta of 0.425 (based on debt beta of 0.00);
- the cost of debt of 147.5 basis point above the risk-free rate; and
- a gamma of 0.50.

2 Risk free rate

The risk-free rate of return in the CAPM is generally derived from government bonds rates. The key issues for the risk free rate are twofold: the appropriate bond maturity to adopt, and the period over which any averaging of the rate is taken place.

2.1 Bond maturity

The bond maturity in the CAPM should reflect the decision that an efficient firm would reach in choosing its capital structure. In non-regulated applications, companies investing in long-lived assets generally finance those assets with debt of similar maturities.[1] This allows the company to service its debt from the revenue generated by the assets without being exposed to interest-rate risk. While both the assets and debt will generally have some potential to be liquidated before maturity, it is normally the intention of management to keep both in place through to the end of their lives.

With the exception of the ACCC, there has been universal adoption of the 10-year bond by regulators in pricing decisions. This practice is increasingly seen as uncontentious by these other regulators.

However, the ACCC has continued to adopt the approach of setting the bond rate maturity consistent with the length of the regulatory period. In doing so, it has claimed that a paper it recently commissioned by Associate Professor Martin Lally[2] provides strong support for its position. In this section, we will first review this paper, and other arguments put forward by the ACCC in support of basing the bond maturity on the length of the regulatory period.

---

1 Actually a company would match 'duration' of debt and assets, but this does not change the conclusions.

2 M. Lally, Determining the risk free rate for regulated companies, prepared for the Australian Competition and Consumer Commission, August 2002.

Paper by Associate Professor Martin Lally

In his paper for the ACCC, Associate Professor Martin Lally argued that the ACCC's approach to the risk free rate was correct.

Associate Professor Lally reached his conclusions from developing a regulatory model under which "the only source of uncertainty is in future real interest rates."[3] In this model, it is optimal for the business to finance its debt based on maturity equivalent to the duration of the regulatory period, given that by structuring its debt on this basis, the *ex-ante* value of future cash flows to the business matches the initial capital investment.[4]

In his example, because the optimal setting of debt maturity for the regulated company is to align with the regulatory cycle, it is appropriate for the regulator to set the maturity of the risk free rate in the CAPM and WACC to align with the regulatory cycle. It is important to note that it is the interest rate certainty over the period that drives the optimal decision on maturity of debt for the company, not the amount of the rate or how the rate is set.

However, the regulated environment described by Associate Professor Lally is extreme. Although he makes no attempt to relate his set of assumptions to an actual regulatory environment, at best it would be consistent with very strict rate of return regulation – in that businesses exactly earn the WACC set by the regulator. This is due to his assumptions that:

- output that will be sold is known with certainty;
- there is no uncertainty over operating costs;

---

3 Ibid, p5.

4 For this result to hold there must be an upward sloping yield curve and minimal transactions costs of refinancing debt at each regulatory period. If these costs are large, the optimal refinancing period may change (be lengthened) even with Lally's other assumptions.

- there is no regulatory risk;[5] and
- the only risk facing the business is the impact of interest rate fluctuations on output prices.

However, his assumed regulatory arrangements ensure that the regulated entity is not exposed to interest rate risk given that changes in interest rates are used to adjust final product prices, ensuring that the business earns exactly the WACC.

It is important to note that Associate Professor Lally's results will generally not hold if his key assumptions are relaxed to be more in accord with the real world.

Where final demand is uncertain or operating costs can vary it can no longer be concluded that the *ex-ante* returns to the business will equal *ex-post* returns with certainty simply by structuring debt to mature at the expiry of the regulatory period. If uncertainty over costs and regulatory risk is introduced his results do not hold. To highlight this issue, consider regulatory risk – it is apparent that no regulatory system in Australia is capable of delivering the regulatory certainty assumed by Associate Professor Lally.

As Associate Professor Lally's results will then not hold by definition, the question becomes one of determining which bond maturity should best be used in setting the appropriate regulatory WACC.

Regulatory decisions should not change commercial decision making which would otherwise be efficient and socially desirable outcomes in an unregulated environment – rather, regulatory decisions should be consistent with those outcomes. Accordingly, regulatory decisions should not distort financing decisions away from those that would otherwise be most efficient. Assuming that a company can have a lower cost of capital by structuring its debt based on a bond maturity approximating the regulatory period implies

---

5 Associate Professor Lally does not state this assumption, but it is necessary to his analysis. The regulated firm must have certainty that the regulatory regime will be stable for the life of the assets.

that there are arbitrage opportunities available with regulated businesses that do not structure debt in such a way.

This seems unlikely and analogous situations can be drawn from other markets. Consider the case of an electricity generator, who is faced with a decision whether or not to use contracts to cover their exposure to the electricity spot market. The generator could either sell at the spot rate or buy some insurance and sell on a long-term basis. In equilibrium, the value of these options should be equal. The company could not 'save' by substituting one of these options relative to the other, assuming the markets in which their relative prices are determined are efficient.

Moreover, for a business such as an electricity generator, price sensitivity or the frequency of re-set bears no necessary correspondence to financing structures for such capital intensive assets, notwithstanding the fact that there is no doubt that interest rates over time will, for example, affect bids into the market.

In this light the view expressed by Associate Professor Lally and the ACCC - that setting the bond rate on the length of the review period can lower the cost of capital to the business - is unrealistic. If regular (5-yearly) reviews, for example, lowers the cost of capital relative to for example 10 yearly reviews, then the logical conclusion has to be that the cost of capital should be set daily based on the overnight rate. Indeed, in our view, more frequent regulatory reviews do not lower the cost of capital – the real impact of more frequent regulatory reviews is to increase the cost of capital on account of increased regulatory risk. In other words, the impact of more frequent reviews on the WACC for a regulated business is in precisely the opposite direction suggested by Associate Professor Lally.

A similar claim to that of Associate Professor Lally has been made by the ACCC, where in its Powerlink decision it noted:

> given that investors review investments over short periods, a shorter-term bond rate is the appropriate measure of the risk free rate.[6]

What is ignored by this view is that the regular reviewing of investment does not alter the fact that the asset in question is long-term in nature. It is the investment in long-term assets that is being remunerated by the regulatory rate of return. As noted by Hathaway:

> Imagine you were running a 10-year bond portfolio and every 30 days you valued that portfolio. You would go to the market and use the prevailing 10-year bond rate. You certainly would not use the prevailing short rate to value that bond portfolio. So the interest rate you use has got nothing to do with the review period; the rate you use is the rate consistent with the life of the asset and particularly the risk in your equity risk premium. Anything else gives you an inconsistency.[7]

Moreover, applying Associate Professor Lally's approach will distort economic and commercial decision-making leading to losses in productive and allocative efficiency. Consider for example the trade-offs between operating and capital expenditure. Suppose that the regulated transmission business is considering undertaking capital expenditure on an asset with a life of 10 years, which is expected to reduce operating costs over that same 10-year period. Assume also that the regulatory period is one year.

If the investment decision is based on the one-year bond, then there will be stronger incentives to invest in the capital asset (and disincentives to undertake operating expenditure) than would be the case if the ten-year bond is adopted as the discount rate. This would distort the investment decision compared to the unregulated environment – where the company would base its decision on its (higher) cost of capital. This implies that a

---

6 ACCC, Draft Decision, Queensland Transmission Network Revenue Cap 2002-06/07, July 2001, p. 13.

7 N. Hathaway, Transcript of Public Forum held by ACCC and ORG on the Weighted Average Cost of Capital in the Victorian Gas Access Arrangements, 3 July 1998, p80.

regulated business can base its investment decisions on a lower cost of capital than unregulated businesses. However, irrespective of regulatory practice, a firm's cost of capital remains the opportunity cost associated with investments in long term assets and its decision-making will be determined accordingly. In other words, if a regulator adopts a WACC below the regulated businesses' cost of capital, the result will be that the regulated business will simply not undertake socially desirable investments. Short-term gains for consumers from lower prices will be quickly consumed by higher costs from congestion that is suffered through a lack of investment.

Associate Professor Lally's arguments also ignore the point that equity – for which the return under the CAPM is derived using the risk free rate - cannot be hedged. Equity remains a residual risk irrespective of the debt arrangements, and the risk to equity holders cannot be hedged against in the way suggested by Lally for debt.

Additionally, Associate Professor Lally's model fails to consider the full nature of the CPI adjustment that forms an essential component in any revenue cap arrangement (and indeed in any regulatory arrangement). Not only is there a revisiting of prices annually on account of under- and overs provisions under a revenue cap, but also the CPI adjustment provides an imperfect hedge against a range of movements, including inflation. Even leaving aside time lags in applying inflation to regulated prices, inflationary expectations are not fully reflected in interest rates such that the CPI adjustment does not provide a perfect hedge against the inflationary expectation component in the interest rates.

That is, regulated businesses face an inflation risk that is not addressed in Associate Professor Lally's model. Assume a regulated business secures debt funding as suggested by Associate Professor Lally – the interest rate at the time of the decision will be based on inflationary expectations. The CPI adjustment compensates the regulated business for actual inflation. Hence the existence of inflation risk that is not recognised in Associate Professor Lally's model. Moreover, inflation adjustments are undertaken on an annual basis rather than length of the regulatory period highlighting the gap between Associate Professor Lally's model and established regulatory practice.

In all these examples, the appropriate policy for the business is to match duration with the life of the major asset. This policy holds even where the regulator chooses to adopt a different approach and set the bond rate based on the length of the regulatory period– unless the presence of the regulator provides arbitrage opportunities that do not exist in unregulated markets.

Finally, contrary to the hypothetical regulatory environment illustrated by Associate Professor Lally, regulatory risk is a fact of life in most regulatory frameworks – a point widely accepted by regulators in Australia and stated in the recent Productivity Commission report on the National Access Regime:

> In seeking to reduce access prices that are inefficiently high, the ACCC must have regard to the following principles: (a) that the access prices…(ii) include a return on investment commensurate with the regulatory and commercial risks involved.[8]

Given that there may be a large number of regulatory reviews and changes in regulators over the life of an asset, an investor cannot be confident that the regulatory framework will be unchanging. Even if all of Associate Professor Lally's other assumptions are met, as the regulatory uncertainty increases, the business will be less willing to structure its debt based on the regulatory period and will rationally revert to standard commercial practice of matching debt maturity with asset life.

No regulatory environment in Australia corresponds to that described by Associate Professor Lally. Once we enter a world where investment in long-term assets is not a riskless activity it is critical to consider the opportunity cost of the investment and the fact that investors are financing a long-term investment for which the majority of the value is in future regulatory periods. In such an environment it is best to adopt the standard commercial practice of matching the term of risk free rate with the life of the asset – after all this is the most important economic decision being driven by the choice of the risk free rate. By suggesting that businesses should shift away from standard business practice may have important implications for investment, particularly if it shifts the focus away from long-term investment, a point noted by the Productivity Commission:

---

8 Productivity Commission, Review of the National Access Regime, Inquiry Report No17, September 2002, p332.

> "Given that precision is not possible, access arrangements should encourage regulators to lean more towards facilitating investment than short term consumption of services when setting terms and conditions."[9]

Other arguments put forward by the ACCC

The ACCC has also argued that adopting the length of the regulatory period for the maturity of the risk free rate is appropriate as:

- it minimises expectation errors and is appropriate for the single period nature of the CAPM; and
- there is no need for consistency in the estimation basis of the risk free rate and market risk premium.

NECG does not agree with the ACCC's position on either of these points.

The expected returns of asset owners will only correspond to 'estimated rates' where it is efficient to alter financing to be consistent with the regulatory decision. Given the transaction costs in re-issuing debt and the long-lived nature of infrastructure assets, short-term financing is likely to increase the overall costs to the company.

In addition, although it is correct that the CAPM is a single-period model, the model provides no guidance on the appropriate length of that period. There is nothing in CAPM that supports using the regulatory period. A longer period is supported by the observation that for many regulated businesses, up to three-quarters of the Net Present Value (NPV) is in future regulatory periods, namely the terminal valuation in an NPV calculation of regulated revenue streams.

In adopting the length of the regulatory period as the proxy for the bond maturity, the ACCC is basing the risk free rate on a different time variable than the MRP, for which

---

[9] Productivity Commission (2001), *Review of the National Access Regime*, Position Paper, Canberra, March, page XXII.

estimates are based on the 10-year bond. In his paper written for the ACCC, Associate Professor Lally claims that it is perfectly reasonable for the risk free rate to be set on a different basis to other variables in the CAPM, notably the market risk premium. He concludes:

> Thus the claim that the risk free rate used to determine the market risk premium must be consistently applied throughout the CAPM valuation formula is false.[10]

However, such a model is clearly not the CAPM as can be illustrated with a simple example. The CAPM is generally written as follows:

$$E(Re) = Rf + b^* [E(Rm) - Rf]$$

where

Re	=	cost of equity capital;
Rf	=	risk free rate of return;
Rm	=	market rate of return;
E(.)	=	indicates the variable is an expectation; and
b	=	systematic risk parameter ("beta").

Assume that we are going to apply the CAPM for a company that has a beta of one.

Therefore, $E(Re) = Rf + 1 * [E(Rm) - Rf] = E(Rm) + [Rf - Rf]$

Since the company has the same beta as the market, it must be that - E(Re) = E(Rm). But this can only be the case if [Rf - Rf] = 0, which of course implies that Rf = Rf – namely the risk free rate applied to estimating the market risk premium must be the same risk free rate as used in determining the base risk free rate.

10 Ibid, p12.

Therefore, the term of the MRP and bond rate maturity should coincide. This implies that should a different bond maturity be adopted, not only would an adjustment to the MRP be required but also other costs such as debt issuance and hedging costs would need to be adjusted. In addition, there may be additional impacts on the beta that should be considered.

Accordingly, it is recommended that the ACCC adopt the yield on the 10 year Commonwealth bond as the appropriate maturity for the risk free rate.

2.2 Period of averaging

The ACCC has traditionally adopted a forty-day average of rates immediately preceding the date of the setting of the risk free rate. However, in its SPI Powernet and ElectraNet decisions, the ACCC reverted to using a 10-day moving average having flagged the possibility of a 5-day moving average in the SPI Powernet draft decision.

Conclusion

Consistent with the ACCC's SPI and ElectraNet decisions we have estimated the risk free rate based as a 10-day average of the yield to maturity of the 10-year Commonwealth bond. As of 1 September 2003 this was 5.55%.

3 Market risk premium

The market risk premium (MRP) is the amount an investor expects to earn from an investment in the market above the return earned on a risk-free investment. The key difficulty in estimating the MRP arises from it being an expectation and therefore not being directly observable. As a result the choice of an appropriate rate is inevitably *ad hoc*. Generally a range of plausible values is identified and the MRP is chosen within the range, most commonly at the midpoint.

In determining the appropriate MRP to apply, we consider:

- use of historical data to generate a range; and
- the assessment of an appropriate point in that range.

3.1 Historic evidence

In assessing historical evidence, the generally accepted range among corporate finance professionals in Australia has been 6% to 8%.[11] This range is largely favoured because of empirical evidence of the historical, realised MRP in Australia dating as far back as 1882. In the absence of additional evidence, the midpoint of 7% was often picked as the point estimate. In 1999, Davis presented a range for MRP of between 5% and 8%, and noted that the midpoint of 6.5% "is not unreasonable."[12] Section 3.2 of Schedule 6.1 of the National Electricity Code also notes that the MRP has averaged 6.6% since 1952.

---

11 For example, see R. Officer, "Rates of Return to Shares, Bond Yields and Inflation Rates: An Historical Perspective," in *Share Markets and Portfolio Theory*, 2nd ed, 1989 University of Queensland Press, St Lucia, 1989, pp. 207-11.

12 K. Davis, "Comments on the Cost of Capital: A Report prepared for the ACCC," April 1999.

Recently, Dimson, Marsh and Staunton[13] undertook a comprehensive study of financial market performance for sixteen countries from the end of the nineteenth century to the beginning of the twenty-first, finding that the MRP for the Australian economy was 7.0% over this period. The authors noted that the better performing equity markets were those of resource rich economies such as Australia.

Historical estimates of MRP are given in Table 1.

Table 1: Historical estimates of MRP

Source	Market risk premium (%)
Officer (1989) (based on 1882-1987)[14]	7.9
Hathaway (1996) (based on 1882-1991)[15]	7.7
Hathaway (1996) (based on 1947-91)[16]	6.6
NEC (based on 1952-99)[17]	6.6
AGSM (based on 1964-95, including October 1987)[18]	6.2
AGSM (based on 1964-95, excluding October 1987)[19]	8.1
Dimson, Marsh, Staunton (2002) (based on 1900-2000)[20]	7.0

13 Dimson E, Marsh P, Staunton M, "Triumph of the Optimists: 101 Years of Global Investment Returns", Princeton University Press 2002.

14 R. Officer, op cit, pp. 207-11.

15 N. Hathaway, "Market Risk Premia", unpublished manuscript.

16 Ibid.

17 National Electricity Code, schedule 6.1, section 3.2.

18 IPART, "Regulation of New South Wales Electricity Distribution Networks," section 5.4.2, Table 5.4, December 1999.

19 Ibid.

The historic data set out above is consistent with a range of 6.0% to 8.0%.

3.2 Appropriate point within the range

In response to a belief that the MRP has declined in recent years, most regulators including the ACCC have adopted a figure at the bottom end of this range – namely 6%.

The ACCC has adopted this practice, with its own commissioned consultant, Associate Professor Lally recently noting:

> To summarise this review of evidence on the market risk premium in the Officer CAPM, the estimates are .07 from historical averaging of the Ibbotson type, .056 from historical averaging of the Siegel type, .07 from the Merton methodology, and .040-.057 from the forward-looking approach. If a point estimate for the last approach is .048, then the average across these four approaches is .061. In addition various other methodologies have been alluded to, for which Australian results are not available but which have generated low values in the markets to which they have been employed. All of this suggests that the ACCC's currently employed estimate of .06 is reasonable, and no change is recommended.[21]

Associate Professor Lally's results are consistent with other recent estimates of historic MRP (including Dimson, Marsh and Staunton). However, his estimates of forward looking MRP are likely to understate the MRP given that almost all the estimates considered are based on data during the bull market, which is unlikely to provide a valid basis for estimating a forward-looking MRP at the current time. Averaging Associate Professor Lally's other estimates produces a value closer to 7.0% - the mid point of the range of historical estimates.

---

20 Op cit.

21 Lally, M, The Cost of Capital under Dividend Imputation, a report for the ACCC, June 2002, p34.

In considering the appropriate point for the MRP within this historical range, we will consider the following issues:

- the distinction between the ex-ante and ex-post MRP;
- benchmarking approaches to MRP; and
- the relevance of surveys of MRP at the present time.

3.2.1 Ex-ante ex-post distinction

A number of regulators have justified adopting a MRP at the bottom end of the historical range based on evidence of recent reductions in the ex-post MRP. Given the need for data of significant duration (at least 30 years) to provide statistically robust results, such data should be treated with care, particularly given recent volatility in the MRP. In addition, interpretation of such data requires the need to understand the distinction between *ex ante* (i.e., expectations going forward) and *ex post* (i.e., historical) data on MRP and the relationship between these measures. This is illustrated by the examples contained in Box 1. In broad terms:

- if the *ex ante* MRP is constant, the *ex post* MRP will also be constant and equal to the *ex ante* MRP;
- an increase (decrease) in the *ex ante* MRP will result in a decrease (increase) in the *ex post* MRP in the period that the change in expectation occurs. In the period when the *ex ante* MRP is changing, the *ex post* MRP will move in the opposite direction;
- a small movement in the *ex ante* MRP can cause a much larger impact on the *ex post* MRP - in the example contained in Box 1, an increase of only 0.1% in the *ex ante* MRP resulted in a decrease in the *ex post* MRP of 0.99% (7% - 6.01%); and
- the *ex post* MRP moves down and then up before settling on the new equilibrium. The *ex ante* MRP moves directly to the new equilibrium.

Accordingly, a declining MRP over the past decade is entirely consistent with the forward-looking MRP increasing, perhaps substantially. In fact, in the US, the very high returns and *ex post* MRP in the stock market over much of the 1990s was used to support arguments that the *ex ante* MRP was declining. The key point is that a period when the *ex post* MRP departs significantly from the long-run average is likely to be a period when the *ex ante* MRP is changing but in the opposite direction.

Box 1 Examples of relationship between *ex ante* and *ex post*

Assume a simple market that is expected to earn $100,000 of cash flow to distribute to shareholders as a dividend in perpetuity (i.e. no growth). If the risk-free rate of interest is a constant 3% and the *ex ante* MRP is 7%, the cost of equity capital is 10%.[1] Since the earnings is a perpetuity, the value of the market is the earnings divided by the cost of equity capital:

Value of the market = $100,000 / 10% = $1,000,000

If the parameters of the valuation do not change, the value of the market will not change, and the annual return to the shareholders will be the perpetuity. As time passes the *ex ante* MRP of 7% will also be observed as the *ex post* MRP.

Now assume the *ex ante* MRP increases to 7.1% over the course of a year. By the end of the year the cost of equity capital will be 10.1%, and the value of the market will be

Value of the market = $100,000 / 10.1% = $990,099

During this year the shareholders will realise a return by dividend of $100,000 but a loss of value of the investment of $9,901 ($1,000,000 - $990,099) for a net return of $90,099 on the investment of $1,000,000. This gives the shareholder an *ex post* return in this year of 9.01% and a MRP after deducting the risk-free return of 6.01%.

If in the subsequent year the *ex ante* MRP remains at 7.1%, the value of the market will not change and the *ex post* MRP will also be 7.1%.

Alternatively, consider a case where the *ex ante* MRP increases gradually from 7% to 10% over a period of ten years. That is a very gradual change in the MRP, averaging only 0.3% per annum. Using the same assumptions as above, the *ex ante* increase of 3% will increase cost of equity capital to 13% and decrease the value of the market to $769,231. The *ex post* MRP over the ten years will be 5.44%. For the *ex ante* MRP to increase from 7% to 10% over ten years, the *ex post* MRP would have to be observed as decreasing, averaging about 5.44% over the same 10-year period.

3.2.2 Benchmarking approach to MRP

An alternative way of setting a MRP is through a benchmarking approach. Australia is an open and international economy. Investment funds move freely into and out of the country and the currency. As of September 2000 non-resident investors owned 37.5% of the value of the Australian Stock Exchange, the largest single shareholder group by far. In addition, as of 31 March 2002, non-residents held over 33% of all Commonwealth government securities.[22]

The Australian debt and equity markets have only been integrated into world markets for around 20 years. Prior to deregulation, market prices (and in turn the MRP) were significantly affected by government intervention, in particular the restrictions on foreign ownership of shares and exchange rate controls. This resulted in prices of shares and government bonds being predominantly determined by domestic (rather than international) factors. Given these circumstances, it is unlikely that the *ex post* MRP in this market provides the best estimate of an *ex ante* MRP in the current (international) market.

In the absence of sufficient relevant historical information from the current market, an alternative approach to estimating the MRP is through a benchmarking approach. With this approach, a benchmark country is chosen based upon it having a reliable estimate of MRP. Then the potential differences between the MRP in that country and the MRP in Australia are evaluated. These could include taxation, country risk, estimation time horizon and market composition differences.

Bowman recently estimated the Australian MRP from the US MRP using a benchmarking approach to be 7.8%.[23] Similarly, Ibbotson Associates suggest that the US market risk

---

22 Reserve Bank of Australia, "Bulletin Statistical Tables," http://www.rba.gov.au/Statistics/Bulletin/EO3hist.xls

23 R. Bowman "Estimating the Market Risk Premium," *JASSA*, Spring 2001, pp10-14. However, We understand that Professor Bowman has since revised his benchmarked estimate of the market risk premium in Australia to 7%.

premium is 7.76% and that based on Australia's country credit rating, the expected return on the Australian market is 1.53% to 2.26% higher than for the U.S.[24]

This benchmarking approach suggests that a figure of at least 7.0% is justified for Australia.

3.2.3 Survey data

ESC and IPART have recently made reference to a number of survey studies of MRP. These include:

- two studies by Welch[25,26] – who surveyed academics finding MRP of 7.1% and 5.5% respectively;
- Graham & Harvey[27] – who surveyed 1107 CFO's between 2000 and 2001, resulting in a range for the MRP of 3.6-4.7%;
- Mercer Investment consulting[28] – who surveyed brokers finding a range of 3.0-6.0%, noting that in its own advice it adopts a figure of 3.0%; and

---

24 Ibbotson Associates, (2001), "International Cost of Capital Report 2001," valuation.ibbotson.com.

25 Welch, I., 2000, "Views of Financial Economists on the Equity Premium and other Issues," The Journal of Business 73(4), 501-537.

26 Welch, I., 2001, "The Equity Premium Consensus Forecast Revisited," Working Paper, Yale University.

27 Graham, J., C. Harvey, 2001, "Expectations of Equity Risk Premia, Volatility and Asymmetry from a Corporate Finance Perspective", working paper, Duke University.

- Jardine Fleming Capital Markets[29] – who surveyed 61 respondents in Australia, of which 35 were non-academics, finding an average expected MRP in Australia of 4.73%.

On face value, surveys have a substantial advantage over historical estimates of MRP. Properly constructed, they should provide actual forward-looking opinions. However, there are a number of critical dimensions to their validity:

- the nature of the participants in the survey;
- the biases the participants may have with respect to the issue being surveyed; and
- the time horizon the participants may considered.

Considering each of the studies against these dimensions raises a number of critical flaws.

Welch surveys

The surveys by Ivo Welch were to be based upon views of the US markets. The intention of the first survey was that the participants would be professional financial economists, primarily academics. The second survey was "by invitation" and was restricted to professors of finance and economics.

A key concern with the findings of Welch's surveys is the role that Welch himself took. His first survey was open to everyone who visited his website, the second survey was by invitation only. Welch disclosed that the results of the first survey were higher than his personal view, which casts doubt on the validity of the results of the second survey.

28 Mercer Investment Consulting, Victorian Essential Services Commission Australian Equity Risk Premium, 1 July 2002.

29 Jardine Fleming Capital Partners Limited, The Equity Risk Premium – An Australian Perspective, Trinity Best Practice Committee, September 2001.

Accordingly, it is thought that the first survey provides an inherently more credible estimate of the MRP and therefore ought to be preferred.

Graham and Harvey

Graham and Harvey surveyed CFOs in the US on their estimates of the forward-looking MRP at various horizons. They found that:

> "the one-year risk premium is highly variable through time and 10-year expected risk premium is stable. In particular, after periods of negative returns, CFOs significantly reduce their one-year market forecasts, disagreement (volatility) increases and returns distributions are more skewed to the left (i.e., low). We also examine the relation between ex ante returns and ex ante volatility. The relation between the one-year expected risk premium and expected risk is negative. However, our research points to the importance of horizon. We find a significantly positive relation between expected return and expected risk at the 10-year horizon." (taken from the abstract).

While CFOs of large corporations may be familiar with the issue being surveyed and with the "real world", their focus may be excessively short term and be influenced by recent historical outcomes.

Mercer

Mercer Investment Consulting surveyed brokers. While it can be argued that these people would be both knowledgeable and interested in the topic, there are a number of concerns in basing MRP estimates on the views of brokers:

- they are not likely to be particularly knowledgeable of the theoretical and empirical research on the issue; and
- their time horizon can be questioned such that their forward-looking assessments are strongly correlated with the recent past but have no predictive power.

Jardine Fleming Capital Markets

The results of the Jardine Fleming survey do not appear to match with the risk profile of the Australian and US equity markets. The survey makes two unusual conclusions: firstly that past MRP was higher in the US than Australia by about 40 basis points; and secondly that the expected MRP in Australia is about equal to that in the US. For these to be true, Australia's equities would have to be no less risky than equities in the US. This seems unlikely.

Conclusion on surveys

In general, surveys are interesting, but they may tell us more about the people being surveyed than about the issues being surveyed. As a result, the biases created reduce the validity as an appropriate estimator of a forward-looking MRP.

3.3 Conclusion on MRP

Whilst we know that the MRP varies over time, accurately quantifying this variation is impossible in practice. Indeed, the most recent data would suggest that the MRP has been increasing over the past year in ex post terms, although for the reasons outlined above, we believe the critical issue is the long term average for the assessment of the MRP.

As noted above, the historical range for the MRP favoured by finance professionals has been 6.0 to 8.0%. Evidence suggesting short term declines in MRP does not provide valid support for policy setting. Evidence on benchmarking approaches to the MRP also suggests a figure at the high end of the range may be appropriate. Such findings are consistent with the recent findings of Dimson, Marsh and Staunton noted earlier, who found that the MRP for the Australian economy was 7.0% over the last century.

It is also important that the estimation of the MRP is on a basis consistent with the bond maturity used to set the risk free rate. If the ACCC is to continue its current practice of using the 5-year bond for the risk free rate (which we advise against), it needs to devise a methodology for adjusting the market risk premium and other variables in CAPM to account for the differing duration.

Given clear and well-established historical precedent, we believe that the most appropriate MRP to adopt is 7% and that there is no case for a MRP below 6.5%. However, in the context of recent regulatory precedent and the alignment of regulators on this issue, EnergyAustralia recommends that a MRP of 6% be adopted for this review.

4 Debt

The cost of debt capital for a company will be related to market rates of interest on debt, the appropriate maturity of debt and the assumed capital structure.

A number of relevant issues in relation to debt are discussed below.

4.1 Capital structure

Standard regulatory practice by the ACCC and other regulators in all energy decisions has been to assume a benchmark gearing of 60%. NECG agrees that is approach is reasonable for EnergyAustralia providing that relevant debt and equity costs are considered consistently on this basis.

Therefore, in the remainder of this paper gearing of 60% is assumed.

4.2 Debt margin

Table 2 sets out the debt margin provided in regulatory decisions over the past year.

Table 2: Debt margin allowed in recent regulatory decisions

Date	Regulator	Business	Margin (bp)	Notes (if any)
Jul-03	ESCOSA	Tarcoola-Darwin railway (benchmark estimate)	120	Based on "A" credit rating and assumed ACCC allowance for ARTC still appropriate
Jun-03	OTTER	Aurora (draft)	125	Proxy value based on credit rating of "A"
May-03	Offgar	Dampier-Bunbury	120	Regulator approved value submitted by Epic in 1999
Apr-03	QCA	Burdekin River Irrigation Area (draft)	180	Estimate of market based cost of raising debt based on BBB rating as of October 2000
Dec-02	ACCC	SPI Powernet	120	Considered firm with "A" credit rating would require margin of 120 basis points for 5 year borrowing. Incorporates 10.5 basis points for debt raising costs
Dec-02	ACCC	ElectraNet	121.5	Based on "A" credit rating and including 10.5 basis points for debt raising costs.
Dec-02	ACCC	ABDP (NT Gas)	154	Based on premium over 10 year bond rate for corporate issue of BBB+ of similar maturity.
Nov-02	ACCC	GasNet	158.5	Based on corporate issue rates for (benchmark) BBB+ rating. Includes 12.5 basis points for debt raising costs
Oct-02	ESC	Vic gas distributors	170	Estimate of market cost of raising debt based on BBB+ rating. Includes 5 basis points for establishment costs
Sep-02	QCA	Gladstone Area Water Board	160	Estimate of market based cost of raising debt based on BBB rating as of June 2002

While this is a relatively limited sample, these decisions have resulted in the following ranges being set for the debt margins (excluding any transactions costs):

- for BBB credit rating a debt premium of 160-180 basis points;

- for BBB+ credit rating a debt premium of 130-165 basis points; and
- for A credit rating a debt premium of 120 basis points.

We note that in its most recent electricity and gas decisions the ACCC has determined a benchmark credit rating for the company in question based on the credit rating of listed entities operating in the same sector. Current Standard & Poors ratings of major energy businesses are set out in Table 3.

Table 3: Credit rating of major energy utility businesses (April 2003)

Company	Rating	Gearing	Sector
AGL	A	52%	Electricity and gas distribution
AlintaGas	BBB	49%	Gas distribution
United Energy	A-	42%	Electricity and gas distribution
ElectraNet	BBB+	75%	Electricity transmission
Origin Energy	BBB+	29%	Gas transmission and electricity retailing
Envestra	BBB	80%	Gas distribution
GasNet	BBB	67%	Gas transmission

Source: Standard and Poors Australian Report Card: Utilities, 23 April 2003. SPI Powernet (A+), ETSA Utilities (A-), Powercor (A-) and TXU (BBB) have all been excluded from this table as their rating primarily reflects the rating of the major controlling shareholder. Note that activities of AlintaGas now include electricity distribution following its acquisition of Aquila Inc's interest in United Energy.

It can be seen from Table 3 that the three comparators that have a gearing at or above the ACCC's benchmark level (60%) have credit rating of either BBB or BBB+. Similarly, the companies with ratings above BBB+, namely AGL and United Energy both have gearing well below 60%. While a number of factors go into determining a company's credit rating, this data suggests that adopting a credit rating of BBB+ for a utility company with benchmark gearing of 60% would not be inconsistent with market observations.

Just as is the case for bond rates, debt margins are volatile. As of 1 September 2003, CBA Spectrum estimate that the margin over the risk free rate for a 10-year bond issue of rating 'BBB+' based on a 10 day average consistent with the risk free rate is 99 basis points.

Current debt margins are much lower than was the case only a few months ago, and are lower than established regulatory precedent. At this time of EnergyAustralia's submission to IPART on its distribution assets, the margin for BBB+ debt was 135 basis points. To ensure consistency with this submission, EnergyAustralia has requested we adopt a value of 135 basis points for the purposes of assessing EnergyAustralia's cost of capital.

4.3 Transactions costs

In order to adhere to the principle of financial capital maintenance, it is necessary that regulated businesses be compensated for:

- all transactions costs associated with the raising of debt and equity; and
- all hedging costs associated with securing a position in the market that removes financial risk associated with the regulatory process.

In its recent decision on GasNet, the ACCC accepted the validity of including allowance for the transaction costs of raising debt finance. In doing so, it recognised bank fees and dealer swap margins as legitimate debt-raising costs; and costs paid to equity arrangers for services such as structuring the issue, preparing and distributing information and undertaking presentations to prospective investors as legitimate costs of raising equity. In its recent decision on Victorian gas distributors, the ESC also accepted the validity of including an allowance for non-margin establishment costs in the cost of debt. The ACCC allowance was based on the following estimate from Westpac, which is set out in table 4.

Table 4: Westpac estimate of debt issuance costs (ACCC GasNet decision)

Non margin financing fee	Westpac estimate	Basis points per year (ACCC estimate for GasNet)
Agency fee	$5-10,000 per annum	0.3
Arranger fee	$50,000 per debt issue	0.4
Credit rating fee	$30-40,000 per annum	1.2
Dealer swap margin	5 basis points per annum	5.0
Legal fees	$50-100,000 per debt issue	0.6
Placement fees	5 basis points per annum	5.0
Total		12.5

Source: ACCC GasNet decision, p147.

Applying these estimates to EnergyAustralia would produce a similar figure. Due to the size of debt that requires financing, the agency and credit rating fees would be expected to be lower on a basis point basis. However, this effect would be counteracted by a requirement for multiple debt issues given the size of debt requiring financing.[30] Therefore, consistent with the ACCC's GasNet decision, we have increased the debt margin for EnergyAustralia by 12.5 basis points.

This results in a total debt margin of 147.5 basis points.

30 For the purpose of the final regulatory submission we propose to produce a detailed estimate. This requires information on how EnergyAustralia would be able to sell its benchmark debt requirements into the market.

4.4 Debt beta

The key role for the debt beta is in the de-levering and re-levering of equity betas in the CAPM. What is important as we convert between asset betas and equity betas is systematic risk. The function of the debt beta is to show how there is a sharing of a firm's systematic risk between the systematic risk of equity and the systematic risk of debt. This justifies measuring the debt beta only in terms of its systematic risk, suggesting a relatively low debt beta is appropriate. In order to be consistent with the ACCC's practice on this issue, we have adopted a debt beta of zero in the levering and de-levering of EnergyAustralia's asset and equity beta.

5 Beta and the cost of equity

The CAPM assumes all non-systematic (specific) risks are diversifiable and hence are not provided an expected return in a competitive market. The systematic risk (β or beta) of a firm is the only risk factor incorporated in the CAPM.

The assessment of systematic risk normally involves:

- assessment of the appropriate asset beta for EnergyAustralia; and
- the appropriate measure of the equity beta based on the asset beta and the debt beta.

5.1 Asset beta

The asset beta represents the risk arising from the sensitivity of the operating cash flows generated by an entity's assets compared with the market in general, that is, the market risk associated with an entity's business. Asset betas vary with the volatility of free cash flows and are driven by the sensitivity of those cash flows to fluctuations in the economy.

The following considerations have been applied in estimating an appropriate asset beta for EnergyAustralia:

- an assessment of comparable companies in Australia and overseas; and
- regulatory decisions.

This section considers these factors in turn, and concludes with a brief summary.

5.1.1 Assessment of comparable businesses

Given the lack of listed regulated businesses, regulators have often relied on the "method of similars" to estimate the asset beta of the regulated entity. Given that systematic risk is largely country specific, the most meaningful beta estimates can generally be derived using domestic comparators.

Most recent estimates for the major listed regulated energy businesses in Australia is given in Table 5. In converting these equity betas to asset betas we have used the Monkhouse approach adopted by the ACCC[31] and applied the Bloomberg adjustment.[32] The Bloomberg adjustment is simply an example of an approach has developed to correct for measurement error in estimated betas. This approach makes use of a weighted average of the estimated beta and the assumed mean beta.[33] Analytically this is:

$$\beta^{adj} = \omega * \beta^{raw} + (1-\omega) * \beta^{mean}$$

where ω is the weight given to the estimated beta (β^{raw}). It is standard practice to assume that $\beta^{mean} = 1$.

This approach has significant support in practice. Three of the world's most prominent and reputable purveyors of beta estimates use this approach. The companies and their weighting factors are:

Bloomberg	$\omega = 0.67$
Merrill Lynch	$\omega = 0.65$
Value Line	$\omega = 0.67$

The effect of the adjustment is to adjust the raw beta so that the adjusted beta is closer to the market-wide mean of one.

---

31 Using standard terminology this can be expressed as $Be = Ba + (Ba-Bd)*\{1-[rd/(1+rd)*(1-\gamma)*Te)\}*D/E$.

32 International studies supporting the use of adjusted betas include Sharpe, W.F., Alexander, G.J. and Bailey, J.V. (1995), *Investments*, 5th edition, Englewood Cliffs, Prentice Hall, Blume, M.E. (1971), 'On the Assessment of Risk', *Journal of Finance*, March pp. 1-10; and Blume, M.E. (1975), 'Betas and their Regression Tendencies', *Journal of Finance*, June, pp. 785-795.

33 The assumed mean beta in this approach is comparable to the prior on the true beta in the Bayesian approach of Vasicek (1973). The Bayesian approach also makes use of variances of the prior and estimated beta distributions.

Table 5: AGSM estimates of asset beta – March 2003 (debt beta = 0.00)

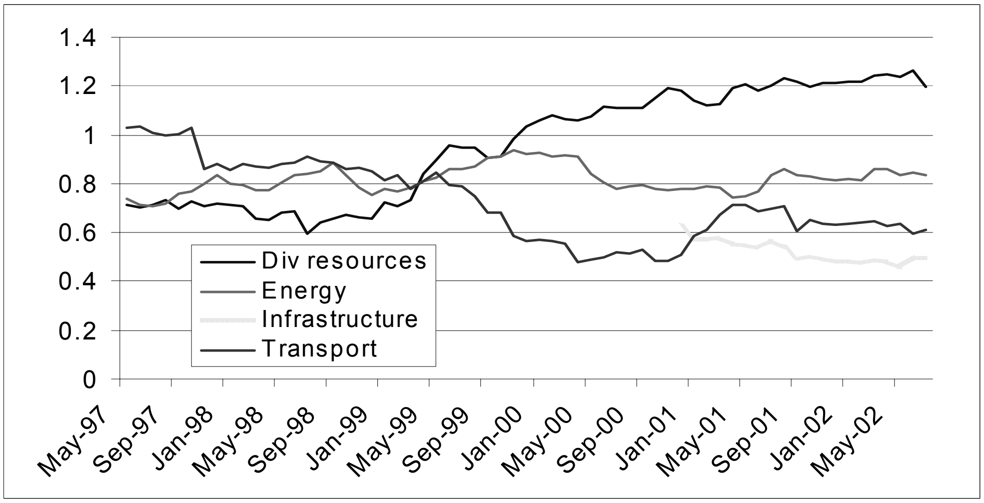
Company	Raw equity beta	Adjusted equity beta	Gearing	Asset beta	R^2
Alinta Gas	0.20	0.47	41%	0.28	0.01
Australian Gas Light	0.06	0.37	36%	0.24	0.00
Envestra	0.34	0.56	74%	0.15	0.04
United Energy	0.08	0.39	46%	0.21	0.00

Source: AGSM Risk Management Service, March 2003.

The data in this table must be treated with caution. Envestra has a highly unusual capital structure and still presents a significant risk of biasing beta estimation.[34] Similarly, caution is required in using the current beta measures of Alinta, AGL and United Energy given that beta estimates exhibit considerable volatility, with the current estimates representing a low point by recent historical standards. For example, in September 2001, the unadjusted equity beta of United Energy was 0.42 – five times higher than the March 2003 value. This is not unusual by historic standards. The volatility in beta estimates generally is shown in figure 1, which depicts movements in industry average betas over time. Note that individual beta estimates can vary considerably more than suggested in this figure. Moreover, regulated businesses cannot hedge against this volatility.

34 Note that as recently as September 2001, the QCA didn't consider Envestra in its comparison of listed entities when estimating a beta value for Envestra's regulated gas distribution activities.

Figure 1: Volatility in industry average betas over time



In considering the AGSM data for policy purposes, it is important to note that the R-squared values for the regressions used to generate the beta values are either zero (AGL) or close to zero. Where this is the case it is not surprising that the beta value is also close to zero because of the statistical relationship involved.

This can be shown below from Sharpe's CAPM:

$$\beta = Cov(R_i, R_m)/var(R_m)$$

where β is the beta, $Cov(R_i, R_m)$ is the covariance of stock i with the market, and $var(R_m)$ is the market variance. Statistically we know that the following holds:

$$Corr(R_i, R_m) = Cov(R_i, R_m)/(sd_i*sd_m)$$

Where $Corr(R_i, R_m)$ is the correlation between stock i and the market. Therefore, beta can also be represented as follows:

$$\beta = Corr(R_i, R_m) * (sd_i/sd_m)$$

As R-squared represents the fraction of the squared error that is explained by the model, as the term (sd_i/sd_m) tends to zero then so will beta.

The AGSM results suggest that the underlying relationship with beta is not stable, so technically the assumptions of the regressions that calculate beta are violated.

Given the problems with the AGSM data, an alternative approach is to consider the asset betas of regulated energy companies listed in overseas markets. In doing so, the process followed was to search globally for statistically significant betas of publicly listed electricity transmission companies, using financial markets information from Bloomberg.

The down loaded firms were ranked on level of statistical significance of the calculated equity beta based on monthly observations. Monthly observations were taken where possible as beta calculated over longer intervals helps to overcome the infrequency of trading problem.[35]

The returns were regressed on the returns of the appropriate market index. For example US firm returns were regressed on the S&P 500. Gearing data was also obtained.[36] The final sample was reduced to five companies through a filtering process based on the similarity of the business operations and the statistical significance of the beta. Any beta with an associated t statistic less than 2 was ignored in the analysis. Raw betas were adjusted in accordance with the standard Bloomberg adjustment.

This process resulted in the sample that is set out in Table 6.

35 Equity betas were calculated using monthly data for a 60 month period. Where it was not possible to obtain 60 monthly observations, the differencing interval was shortened. For example if only one and one half years of data was available, weekly observations were used so that the beta could be calculated over 60 observations.

36 This is consistent with the Brealey Myers approach to levering and delevering betas from previous decisions.

Table 6: Beta estimates of international energy network businesses (debt beta = 0.00)

Company	Country	Sector	Equity beta	Gearing	Asset beta (based on adjusted equity beta)
National Grid Transco SP-ADR	US	T	0.31	38%	0.34
National Grid Transco Plc	UK	T	0.46	38%	0.40
Red Electrica d'Espania	Spain	T	0.51	35%	0.44
Transener SA	Argentina	T	0.45	90%	0.06
Cia de Transmissao de Ene	Brazil	T	1.28	20%	0.95
Ak Energy	Turkey	D	0.82	19%	0.72
Aksu Energy	Turkey	D	0.82	0%	0.88
Ayen Energy	Turkey	D	0.88	72%	0.26
CGDE	Luxemburg	D	0.38	4%	0.56
Electopaulo Metropolitana	Brazil	D	1.01	77%	0.24
Demasz	Hungary	D	0.52	4%	0.65
Prazska Energetika	Czech	D	0.73	15%	0.70
Demasz	E Europe	D	0.55	0%	0.70
IFX Power	Britain	D	0.77	23%	0.65
CPFL	Brazil	D	0.48	57%	0.28
EMASZ	Hungary	D	0.36	0%	0.57
Horizon Energy	NZ	D	0.57	26%	0.53
Trust Power	NZ	D	0.52	25%	0.51
Florida Public Utilities Co.	US	D	0.32	58%	0.23
United Energy	Australia	D	0.52	46%	0.37
Average transmission			0.60	44%	0.44
Average distribution			0.62	30%	0.51
Average all companies			0.60	34%	0.49

This sample has an average asset beta, based on de-levered equity betas, of 0.49, with the average for the transmission entities being 0.44 and the distribution businesses 0.51.[37] Similar results are obtained if the analysis is restricted to OECD comparators.[38]

---

37 Note that even if the Blume adjustment is not used (which we strongly argue against) the overall average asset beta is 0.41 (transmission 0.38 and distribution 0.42).

38 If the non-OECD comparators (Argentina and Brazil) are removed, the overall average asset beta of the remaining comparators rises to 0.52. The average of the OECD transmission

These estimates are on the whole significantly higher than those of the listed Australian entities (and in turn the Australian estimates are significantly lower than those of the same entities taken one or two years ago). We believe this highlights the need for caution in estimating betas for regulated entities, especially critical given the asymmetric consequences of regulatory error.

It has been argued in some quarters that an adjustment should be made to foreign betas before they are applied as comparators for Australian companies. However, it is submitted that such an adjustment is inappropriate - what we are really trying to ascertain amongst a number of countries is the covariance between the electricity distribution business and the economy in which it operates – as opposed to the covariance between the business and a foreign country (in this case Australia). In practice therefore, it is submitted that international adjustments to beta lose sight of the essential fact that a beta estimates a level of volatility relative to the market with which the covariance is assessed. The essential point is that beta is a *relative* measure of covariance. That relativity is important irrespective of the volatility of one market or another.

In other words, one cannot criticise the irrelevance of a "high" beta measure in a highly volatile exchange on the basis that it will be too high for Australia since the measure simply records the covariance between the stock and that (highly volatile) market – generally speaking, the beta would be even higher were the market to exhibit lower volatility.

5.1.2 Recent regulatory decisions

Beta values in recent regulatory decisions in the energy sector are set out in table 7.

companies is 0.39 while that of the OECD based distribution companies rises to 0.55. Note in this case there is only 3 transmission comparators in the sample.

Table 7: Asset and equity beta - recent regulatory decisions in energy sector

Year	Regulator	Decision	Asset beta	Debt beta	Equity beta
Electricity transmission					
Dec-02	ACCC	SPI PowerNet	0.40	0.00	1.00
Dec-02	ACCC	ElectraNet	0.40	0.00	1.00
Nov-01	ACCC	Powerlink	0.40	0.00	1.00
Feb-01	ACCC	SMHEA	0.40	0.00	1.00
Jan-00	ACCC	Transgrid	0.35-0.50 (0.43)	0.00-0.06 (0.03)	1.02
Electricity distribution					
Jun-03	OTTER	Aurora	Not stated	Not stated	0.95
Oct-01	QCA	Electricity distributors	0.45	0.28	0.70
Sep-00	ORG	Victorian distribution businesses	0.40	0.00	1.00
Dec-99	IPART	NSW distributors	0.35-0.50 (0.43)	0.06	0.97
May-99	ICRC	ACTEW (all activities)	0.40	0.12	0.82
Gas Transmission					
May-03	Offgar	Dampier to Bunbury	0.60	0.20	1.19
Dec-02	ACCC	ABDP (NT Gas)	0.50	0.15	1.02
Nov-02	ACCC	GasNet	0.50	0.18	0.98
Sep-01	ACCC	Moomba to Adelaide	0.50	0.06	1.16
May-01	ACCC	NT Gas (draft)	0.50	0.06	1.16
Dec-00	ACCC	EAPL	0.50	0.06	1.16
Jun-00	ACCC	Central West Pipeline	0.60	0.00	1.50
Oct-98	ACCC	TPA (GasNet)	0.55	0.12	1.19
Oct-01	Offgar	Tubridgi	0.65	0.20	1.32
Apr-01	Offgar	Goldfields (draft)	0.60	0.20	1.19
Oct-00	Offgar	Parmelia pipeline	0.65	0.20	1.32
Gas distribution					
Oct-02	ESC	Vic gas distribution	0.40	0.00	1.00
Dec-01	SAIPAR	SA distribution systems	0.50	0.12	1.06
Oct-01	QCA	Qld gas distribution	0.55	0.26	0.98
Dec-00	OffGAR	Alinta (Mid West/South West)	0.55	0.20	1.07
Nov-00	ICRC	Actew	0.45	0.06	1.03
Jun-00	IPART	AGL Gas Network	0.45	0.06	1.03
Dec-99	IPART	Albury gas distribution system	0.45	0.06	1.03
Mar-99	IPART	Gt Southern energy gas network	0.45	0.06	1.03
Oct-98	ORG	Victorian gas distributors	0.55	0.12	1.19

As can be seen in table 7, the ACCC has consistently applied an asset beta of 0.40 (debt beta = 0) in its recent decisions. This outcome is similar to those allowed by IPART and ESC in its electricity distribution decisions.[39]

Conclusion on asset beta

Given the inherent volatility of beta values, we would very strongly caution giving too much weight to current observations for listed utility businesses in Australia for determining a beta value for a company such as EnergyAustralia. Consideration of international beta values together with regulatory precedent suggests that a range of around 0.40-0.50 can be justified for EnergyAustralia. Based on a debt beta of zero, we have adopted an asset beta of 0.425 for EnergyAustralia. This is slightly lower than adopted in EnergyAustralia's submission to IPART on its distribution assets (0.475 with debt beta of 0.06) to reflect the higher systematic risk in the price cap that is to be applied by IPART.

---

[39] Note that under the QCA's approach to WACC the QCA asset betas are not directly comparable to those of other regulators. Under its approach the debt margin doesn't impact on the overall WACC as the cost of debt equals zero. This is because there is no difference between the debt margin and the debt beta (which is calculated as the debt margin divided by the market risk premium). This results in the premium of the vanilla WACC over the risk free rate being simply the asset beta multiplied by the market risk premium.

6 Gamma

The dividend imputation mechanism used in Australia is intended to ensure that profits are taxed only once for Australian resident taxpayers but this benefit is not intended for foreign shareholders. Dividends that are paid out of after-corporate-tax profits can be accompanied with a 'franking' credit to the extent of the corporate tax paid. The value of franking credits is represented with the parameter gamma (γ).

The value of franking credits will be determined at the level of the investor and will be influenced by the investor's tax circumstances. As these will differ across investors, the result will be a value of the franking credit between nil and full value (i.e., a gamma value between zero and one). There has been an increasing body of literature focused on estimating the value of gamma. The early literature generally found a value of around 0.5. Since this time, debate has become increasingly polarised between those arguing for zero and those arguing for one.

Regulators, including the ACCC, have responded to this uncertainty by setting a value of 0.50 or below.

The market value of distributed franking credits should be established at the market level, not the firm level. So for regulatory purposes, we agree with current regulatory practice that treats firm specific shareholding, including for Government owned businesses, as irrelevant.

Some of the key issues in determining a gamma for the WACC revolve around:

- the identity of the marginal investor; and
- the net impact of recent taxation changes.

6.1 Identity of the marginal investor

The gamma used in the CAPM is generally derived as a market average. Nevertheless, it is the *marginal* rather than *average* value of gamma that is likely to be more appropriate for setting a forward-looking value consistent with the aims of the CAPM. This is because share prices are set by price setting (marginal) investors.[40]

This set of investors may have little relationship to the shareholder mix of a company at a point in time. For publicly listed Australian companies, the marginal investor is likely to be an international investor. This can be seen in light of the extent of foreign ownership of Australian companies and the relative size of the Australian market in global terms.

Foreign shareholders own over 28% of Australian companies[41], non-resident investors own around 37.5% of the value of the Australian Stock Exchange, the largest single shareholder group by far[42].

It is therefore clear that foreign investors exert substantial influence on Australian stock market prices[43]. Indeed, once it is recognised that Australia is a net importer of capital and that Australian equities only represent approximately 1% of the global market, we draw two conclusions:

---

40 Officer RR (1994) "The Cost of Capital under an Imputation Tax System", Accounting and Finance, 34, 1-18.

41 ABS statistics, 5302.0 Balance of Payments and International Investment Position, September Quarter 2001.

42 Information provided by Australian Stock Exchange. Figures for 19 September 2001.

43 Recent research in New Zealand by C. Cliffe ("Ex-Dividend Day Pricing in the New Zealand Equity Market," PhD dissertation, 2002) investigates a number of issues including the identity of the marginal investors for listed New Zealand companies since the introduction of dividend imputation in 1988. The extent of foreign ownership in New Zealand is comparable to that in Australia. The dividend imputation system has changed over the past 14 years from one that did not permit streaming of imputation benefits to foreign shareholders to the point where foreign investors currently receive that benefit. Throughout this period, the marginal investors appear to have been non-resident investors.

- the levels of foreign ownership in Australian equity markets are significant and that this can affect imputation assumptions since a foreign shareholder will at best experience considerable difficulty accessing imputation credits; and[44, 45]
- international ownership levels are well below those assumed in fully integrated world sharemarkets.

Taken together, this suggests that an international investor, who cannot secure the benefit of imputation credits, sets the price for Australian securities. This is the case irrespective of the benefit that Australian investors can secure from imputation credits. The fact that Australians hold the bulk of securities is irrelevant here on account of the significance of international investment (all but the 1% of global investment attributed to Australia) and the impact it thereby exerts (evidenced by the material presence already in the Australian market) in price setting. These factors suggest that gamma may be as low as zero. This is consistent with a recent study by Cannavan, Finn and Gray,[46]which showed that for companies with substantial foreign ownership, the market value of tax credits is close to

---

44 This holds irrespective of whether or not Australian residents are the first to invest in these companies – such investors are merely inframarginal but do not set equilibrium security prices. See also Officer (1988), "A note on the Cost of Capital and Investment Evaluation for Companies under the Imputation Tax", Accounting and Finance, 28, 65-71.

45 In addition, recent tax changes require an investor to hold a stock for 45-days to be eligible for the franking credits. This effectively eliminated arbitraging and dividend stripping, resulting in the end of the secondary market for the credits and eroding the value of franking credits for foreign investors. Accordingly, the only way that foreign investors could secure any benefit from imputation credits would be through practices of dubious legality – to the extent that such "black market" activities exist (by their nature they are not well known) are likely to be accompanied by very high risk and transactions costs, which would seriously discount any such benefit derived.

46 Cannavan D., Finn F. and Gray S. (2001) "The Value of Dividend Imputation Tax Credits," unpublished working paper, Department of Commerce, The University of Queensland.

zero.[47] Were EnergyAustralia to be listed on the ASX we would expect to see significant foreign ownership, given its size would see it listed well inside the top-100 companies on the ASX, even with 60% gearing.

Evidence that for companies with substantial foreign ownership a gamma of zero is observed is not dissimilar to the outcome we find in all competitive markets. For example, in any market, consumers pay for a product at the margin, irrespective of *their* valuation of the product. The difference between a consumer's valuation of a product (as determined by the demand curve) and the market price for the product (at the margin) is the well-known concept of consumer surplus.

It is submitted that this is precisely the outcome that is relevant in the context of the valuation of imputation credits. Whilst Australian taxpayers may gain the benefit of imputation, in the global market that we face, these benefits are simply not relevant to the valuation of Australian public companies. At the margin, the shareholders who set the price do not place a value on imputation credits. Australian shareholders receive a windfall gain by way of the tax system.

And it is in this context that imputation credits need to be considered – imputation (and by implication taxation) is but one of a host of factors that drive investment decisions. Other factors include diversification, opportunity, growth, synergistic benefits and so on.

If the dividend imputation system provides Australian resident investors a windfall gain, then we might expect to observe little or no overseas investment by these investors. The higher returns in Australia that result from the windfall gains would make domestic investment significantly more attractive than overseas investment. There does seem to be

---

47 Nevertheless, it is recognised this area is not settled and that the result of dividend drop-off studies have indicated higher values for gamma. Nevertheless, more recent studies still suffer from selection bias, high standard users and create streaming effects in the data analysis that affect the results.

such an effect. Although there is substantial Australian investment abroad[48], it is far less than we might expect to observe given the integration of world equity markets. Australia constitutes only about one percent of world markets, but far less than ninety-nine percent of equity investments are offshore. This is referred to as "home bias", and an obvious contributor to the existence of substantial home bias in Australia is the windfall gain from the dividend imputation system.

6.2 Recent changes to taxation law

To the extent that Australian domestic conditions are relevant to the setting of gamma, NECG believes that it is too early to assess whether changes to capital gains tax and the full flow through of imputation credits has had any impact on the valuation of gamma for regulatory purposes.

NECG believes there is good reason to suggest there would be little or no change to the valuation of imputation credits based upon the impact of the tax changes on the marginal (that is, foreign) investor. The tax law change will only impact gamma to the extent that the impacted investors play a part in the determination of equilibrium security prices, that is, they are marginal investors. We have already stated that it is not likely to be the case that Australian tax residents are the marginal investors because of the extent of foreign ownership in Australia and the extent of foreign investment by Australians as well as relevant research in other countries. Tax and imputation considerations are but one factor influencing valuation decisions.

Recently Associate Professor Lally has suggested that the appropriate value for gamma should be one (1) based on his view that the model used to assess imputation credits does not accommodate market segmentation.[49] His argument begins with the proposition that the

---

48 For example, total Australian overseas investment amounts to over $375 billion, approximately one half of the capitalisation of the Australian Stock Exchange.

49 Lally, M., (2002), "The cost of capital under dividend imputation," a report prepared for the Australian Competition and Consumer Commission.

Officer model for the assessment of imputation assumes a segmented market. Therefore, he asserts that the application of an international capital asset pricing model market has been rejected. Since markets are assumed to be segmented by the choice of models for estimating WACC, all analysis must be constrained to assuming that the marginal shareholder is an Australian taxpayer.

We reject his analysis on this point.

In spite of any theories, it is an objective fact that the Australian share market and the pricing of Australian securities is in an international market. The Australian markets are not segmented. Theoretical assumptions cannot sweep this fact aside.

We believe that the appropriate approach to these issues is as follows:

- to ignore foreign investors is to ignore the realities of our market environment so we accept that we operate in an integrated (i.e., not segmented) market;
- this suggests that we should use a version of the ICAPM. However, current versions of the ICAPM do not provide an appropriate basis for the estimation of the cost of capital for regulatory purposes and are unlikely to do so for the foreseeable future. Therefore, we use the Officer model as the best available proxy for the ICAPM. Our use of the Officer model does not require that we assume segmented markets; and
- consistent with our assumption that we operate in integrated markets, and consistent with the facts regarding the activities of foreign investors in the price setting process in Australia, we extend our view of integrated markets to the valuation of dividend imputation credits.

We also note that in a recent forum, Professor Officer (whose model was applied by Associate Professor Lally) suggested that there was no case to move away from current gamma settings at this time.[50]

Recommendation

NECG acknowledges that a point in the range between 0.30 and 0.50 for gamma is well established in Australian regulatory decision-making. However, a value of zero is consistent with the marginal shareholder being an international investor. It is noted however that there is considerable uncertainty associated with the value of gamma and that this uncertainty is unlikely to be definitively resolved in the near term. Accordingly, on balance, and noting the uncertainty over the estimation of gamma, we believe that a value within the 0.30 to 0.50 range is justified.

Recognising the ACCC's practice in this area, we have adopted a value of 0.50 for gamma.

---

50 Key WACC Issues in the Regulation of Electricity and Gas, Transmission, an open forum sponsored by SPI PowerNet, ElectraNet SA and GasNet, Monday 24 June 2002.

7 Determination of vanilla WACC

Consistent with the ACCC's post-tax nominal approach, we have determined the following WACC for EnergyAustralia:

Table 8: WACC parameters for EnergyAustralia

Parameter	Value
Risk free rate	5.55%
Market risk premium	6.00%
Debt margin	1.475%
Debt beta	0
Gearing	60%
Asset Beta	0.425
Equity Beta	1.06
Gamma	0.50
Nominal post tax cost of equity	11.89%
"Vanilla WACC"	8.97%

Trowbridge Deloitte Report on Non-insured Risks borne by EnergyAustralia

April 2003

This report written by Trowbridge Deloitte assesses the costs of non-insured faced by EnergyAustralia. The report looks at the whole of EnergyAustralia's network (distribution and transmission) and allocates the costs appropriately between the two classes of assets. This report was provided to IPART in April 2003 as part of EnergyAustralia's submission for the 2003 Network Price Review.

Analysis of Non-Insured Events

EnergyAustralia

May 2003

9 May 2003

Trowbridge Deloitte

Mr Michael Martinson
Group Manager – Regulatory Strategy
EnergyAustralia
570 George Street
Sydney NSW 2000

Dear Michael

Valuation of Non-Insured Events

Please find enclosed our report for your consideration.

We look forward to discussing our findings with you and your colleagues.

Please contact us if you have any questions.

Yours sincerely

Kumar Padisetti — Consultant

David Minty, Nghiep Luu — Fellows of the Institute of Actuaries of Australia

Deloitte Touche Tohmatsu

Analysis of Non-Insured Events

Part I Summary of Findings

Introduction and Scope

Introduction

EnergyAustralia Limited (EnergyAustralia) is in the process of preparing an application for revenue reset for its New South Wales distribution and transmission businesses for the regulatory period beginning 1 July 2004. As part of this reset application EnergyAustralia has engaged Trowbridge Deloitte (TD) to undertake a valuation of the financial impact of events not considered elsewhere in EnergyAustralia's revenue reset submission ('Non-Insured Events').

This study involved a number of meetings with staff of EnergyAustralia and a review of a number of documents provided for the study. Documents referred to in our study are listed in Appendix F.

Scope

The scope for the study was to quantify the expected financial impact of Non-Insured Events identified during our investigations and estimate an equivalent annualised cost of those events.

Rationale for Valuing Non-Insured Risks

Electricity distribution and transmission businesses can potentially incur severe losses due to their exposure to diversifiable risks. Examples of electricity transmission and distribution incidents are shown in Table 1.

Table 1 - Examples of International Transmission/Distribution Incidents

Date	Country	Event	Amount of damage
3/99	Mexico	Mechanical failure	3 million people without power for several hours
2/99	Argentina	Fire destroyed a transformer plant and the main cable ducts.	$US 1 billion
1/98	USA	Freezing rain downed power lines	500,000 people without power for several hours
2/98	New Zealand	4 major power cables collapsed	$NZ 850 million
1/98	Canada	Collapse of transmission towers	1 in 5 Canadians affected for up to 3 weeks. 66 municipalities declared a state of emergency.
8/96	Malaysia	Power tripping	$US 88 million
8/96	USA	High tension power lines sagged close to trees causing electric arcs that shut down the power system.	Two of the largest blackouts in US history.
1/89	Canada	Solar activity caused a magnetic storm which resulted in a power imbalance.	Total blackout for Quebec.
11/85	USA	Transmission line tripping	30 million people without electricity for up to 30 hours.

Similarly to the transmission and distribution companies shown in Table 1, EnergyAustralia is also subject to a number of diversifiable risks. While EnergyAustralia has insurance cover for some of these risks (eg. material loss of assets such as substations and public liability) there are a wide range of risks for which EnergyAustralia is not currently insured.

It is common business practice for companies to limit the level of insurance they purchase from private insurers or reinsurers. Valid reasons for doing so include:

- the company believes the quoted insurance premium is in excess of the true insurance cost;
- the required insurance is not readily available;
- the company has sufficient resources to withstand the risks in question (for example, the risks within the insurance "deductible" limit);
- the company has accepted an attractive premium on a "standard" insurance policy which includes a range of exclusions, and the cost of "*writing back*" the exclusions exceeds the company's perceived value of the excluded risks; and
- the insurer requires the company to bear a reasonable share of each claim to provide incentive for it to manage its risks more effectively.

If no allowance is made for a company's self-insured costs in setting its tariff revenue, then, other things being equal, a business could be encouraged to "over-insure" its risks (possibly on uneconomic terms) and would be allowed to recover those costs through higher tariffs. We consider this to be a perverse incentive.

In our view, each business should not be penalised for selecting the most appropriate/efficient insurance program for its diversifiable risks. This would be achieved if for each business, the "self-insured' costs were estimated and were treated by the regulator as a cash flow expense in setting regulated revenue. This approach requires that these uninsured risks be valued using appropriate quantification methodologies and is also consistent with accounting and taxation standards that put insurance and self-insurance on a similar footing.

Methodology for the Valuation of Non-Insured Risks

This section provides a summary of the approach used in the valuation of significant self-insured risks identified during our discussions with the staff of EnergyAustralia. Our understanding is that EA has already made an allowance in its operating expenditure for the non-insured risks that we identified because the timing of the deadlines meant that EA had to make an assessment prior to the completion of our report. This report provides an independent view for the appropriate value of non-insured events for EA. Our understanding is that the annual allowance made by EA for its distribution assets in respect of the risks quantified in this report was $2.085m and $2m in respect of general liabilities and other non-insured events respectively. These figures compare to $2.6m and $2.9m for our annual risk estimates in respect of EA's distribution assets for general liabilities and other non-insured events respectively. We have also estimated an annual risk premium of $0.44m for EA's transmission assets for the non-insured events covered in this report.

In our view the self-insured risks we have valued in this report are generally diversifiable and hence they are not reflected in the company's asset beta. By definition asset beta reflects only the non-diversifiable or systematic risks borne by the company. In theory, EnergyAustralia should be able to obtain insurance for these diversifiable risks. However, the actual market may not provide insurance cover for certain risks due to capital or other constraints.

Calculation of Central Estimate

We have quantified the non-insured risks using market information, our research and other information provided by EnergyAustralia staff. The approach we have taken in quantifying these non-insured risks can be summarised by the following formula.

Central Estimate = (Expected Amount at Risk) x (Probability of Occurrence)

In our view an adjustment to the central estimate would be appropriate for some risks. This is fully discussed in Appendix B, and would generally result in an increase in the expected total self-insurance cost. However, for the purpose of this report we have not included any adjustment to the central estimate in our calculation of the risk premium estimate.

In addition, we present a detailed discussion of the impact of the September 11 events on the level of insurance premiums and terms and availability of cover is included in Appendix A.

Summary of Valuation of Self-Insured Risks

As mentioned previously EnergyAustralia has decided to self-insure risks for various reasons. Table 2 shows the identified self-insured diversifiable risks along with a column indicating whether the magnitude of that risk is considered in detail in this report.

Table 2 - Availability of Insurance for Self-Insured Risks

Uninsured risks	Considered in this Report
Public Liability (including that arising from bushfires)	Y
Damage to poles/substations/wires	Y
Motor fleet	N
Easements Disputes	Y
Unrecovered costs of repairing damage caused by third parties	Y
Asbestos liability	N
Terrorism risks	N
Workers' compensation liabilities	N
Asset stranding risks	Y
Increased maintenance or other costs due to aging of assets	N
Potential under-recording of supply	N
Variations in insurance terms	Y
Credit risk of counterparties and insurers	Y
Business interruption risks	N
Regulatory risks	Y
Environmental risks	N

While some of these risks may have a low likelihood of occurrence their financial impact can be significant. Therefore, it is prudent to recover an appropriate risk premium for the self-insured amounts. We have grouped these uninsured risks into the following four categories:

- Property related risks
- Currently insured risks
- Credit risks
- Other risks

Our estimate of the costs of self-insured risks considered in this report is tabulated in Table 3:

Table 3 - Summary of Estimated Annual Costs of Self-Insured Risks to EnergyAustralia

Self-insured risks	Risk Premium Estimate ($millions p.a.)	Transmission ($millions p.a.)	Distribution ($millions p.a.)
Property Related Risks			
Tower failure from non-catastrophic Events	0.69	0.01	0.68
Tower failure from catastrophic Events	0.36	0.05	0.31
Damage by 3rd parties	1.05	0.19	0.86
Damage to substations (including within $10m deductible)	0.80	0.16	0.64
Total Property Related Risks	2.90	0.41	2.49
Current Insurance Risks			
Public/general liability (excl bushfires)	2.65	0.00	2.65
Bushfire liability	0.40	0.02	0.38
Total Current Insurance Risks	3.05	0.02	3.03
Credit Risks			
Counterparty credit risk	0.06	0.01	0.05
Insurers' credit risk	0.01	0.00	0.01
Total Credit Risks	0.07	0.01	0.06
Total for Other Risks	-	-	-
Total costs associated with self-insured risks	**6.02**	**0.44**	**5.58**

The reasons that certain risks in Table 2 were not considered in detail in this report are as follows:

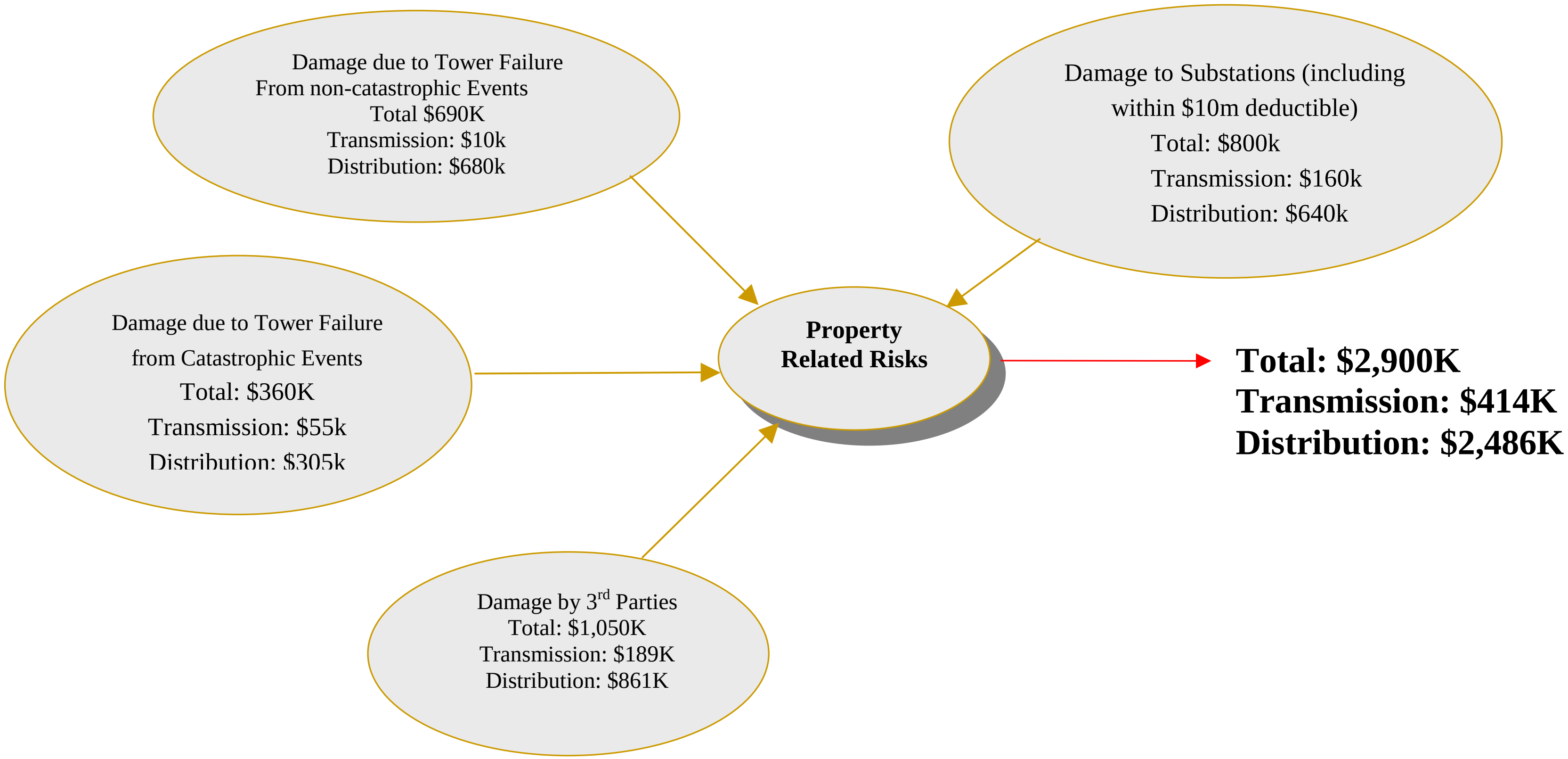
- In our view, some of the risks in Table 2 are better dealt with via risk mitigation strategies rather than making a specific allowance for the cost of incidents. For example, for environmental risks, we believe it is more appropriate to allow for efficient operating expenses to manage the potential costs of fines for breaches of environmental law rather than to calculate the expected costs of those fines.

- EnergyAustralia's view was that certain risks did not require an independent quantification because they were either of immaterial magnitude, subject to very little uncertainty or have already been independently quantified by another external consultant. For example, the expected future costs of workers' compensation liabilities have been independently estimated by a consulting actuary.

We understand that the risks not considered in detail in this report are included in other elements of EnergyAustralia's submission.

Property Related Risks

Figure 1- Annual Risk Premium Estimates for Property Related Risks



Damage to Towers and Wires

EnergyAustralia self insures for the property damage to its towers/poles and wires.

We have identified four main perils which we believe pose a potential risk to EnergyAustralia's tower and wires and for which a self-insurance premium should be allowed for in the regulatory reset.

- Failure of towers/poles (for example, due to termites, fungal decay and other non catastrophic causes);
- Impacts of severe storms;
- Impacts of bushfires;
- Impact of earthquakes.

Table 4 shows our central estimate for the self-insurance of EnergyAustralia's tower lines[1] in respect of catastrophic risks.

Table 4 – Risk Premium Calculation

Cause	Cost per km[2]	Estimated km destroyed per annum	Risk Premium
	$000s/km	km	$000s
Severe Storm	75	2.5	188
Bushfire	75	1.9	142
Earthquake	75	0.4	30
Central Estimate			360

Based on information provided by EA, this annual premium can be segmented into $305,000 for EA's distribution assets and $55,000 for EA's transmission assets.

Table 5 shows the calculation of risk premium for tower failures due termites, fungal decay and other non-catastrophic causes.

[1] Tower Lines consists of the towers/poles, wires, insulators and other components required to secure the wires as well as indirect costs including salaries, transportation, temporary replacement etc.

[2] Including additional indirect costs associated with emergency situations

Table 5
Risk Premium for Tower Failures[3]

Failure Rate	Number of Poles	Cost per Pole[4] ($000s)	Risk Premium ($000s)
0.01%	550,000	12.5	690

Based on information provided by EA, this annual premium can be segmented into $680,000 for EA's distribution assets and $10,000 for EA's transmission assets.

Damage to Substations

As part of its regulated asset base EnergyAustralia has approximately 236 transformer substations. While EnergyAustralia has insurance which covers property damage to its substation valued at greater than $10m this insurance has a deductible of $10m. In effect EnergyAustralia self-insures for damage up to $10m.

Table 6 shows our central estimate for the self-insurance of EnergyAustralia's substations.

[3] Potentially included within OPEX allowance due to regular incidence of risk
[4] including replacement pole, wires, other components, staff salaries, other costs.

Table 6 – Risk Premium Calculation

Substation Category	Incident Rate per Annum per Substation	Number of Substations	Average Replacement Cost	Average Claim Cost[5]	Risk Premium
	%		$000s	$000s	$000s
<$10m	0.125%	180	5,500	1,925	433
>$10m	0.125%	56	15,000	5,250	367
Central Estimate					800

Based on information provided by EA, this annual premium can be segmented into $640,000 for EA's distribution assets and $160,000 for EA's transmission assets.

Damage by Third Parties

EnergyAustralia's network is the largest electricity distribution network in Australia. The EA network connects more than 1.4 million customers across a franchise area spanning about 22,300km^2. EA's network covers some of the most densely populated areas in New South Wales including the Sydney, Central Coast and Hunter regions. The expansive coverage of the EA network means that its network assets are exposed to potential damage from third parties. The damages would include both accidental damage and malicious damage to the network.

EA is able to recover a percentage of the total cost of third party damage:

- Recoveries from the identified parties causing the damage; and
- Insurance recoveries. These have been negligible as the majority of EA's network assets are not insured for property damage.

[5] While EnergyAustralia has insurance coverage for claims greater than $10m for substations worth greater than $10m, based on the assumptions we have adopted it would be extremely rare for the claims costs to exceed this $10m deductible.

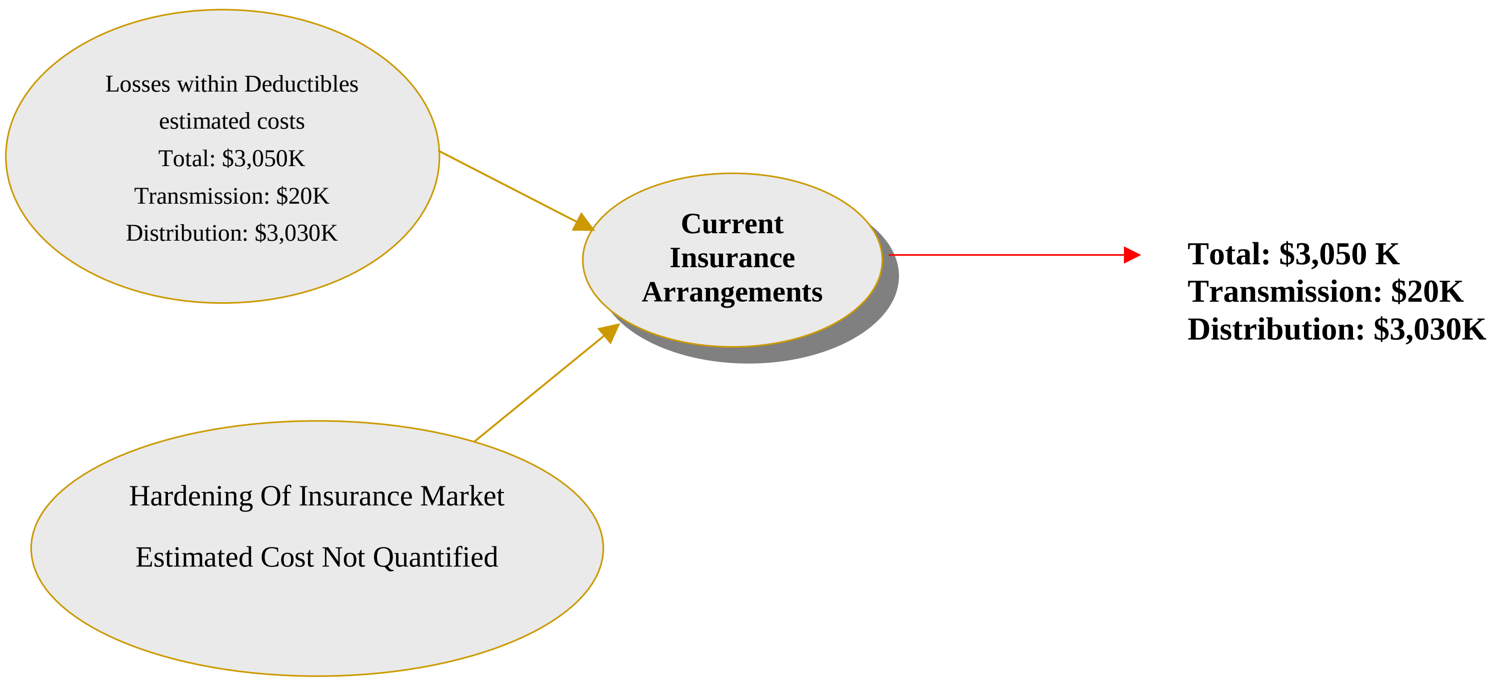
Analysis of the historical data shows that EA has been able to identify and invoice about 68% of the costs from third party damage. Further analysis using invoice data covering the period from 1 July 1993 to 28 February 2003 shows that EA has achieved an average recovery rate of about 92% of total invoiced amounts.

We estimate the annual risk premium in respect of unrecovered third party damage to the EA network is approximately $1,050,000 pa based on the average of the net cost to EA over the last four financial years. Based on damage report information provided by EA, this annual premium can be segmented into $861,000 for EA's distribution assets and $189,000 for EA's transmission assets.

We have been advised by EA that the unrecovered costs are not allowed for through any regulatory mechanisms including the inclusion of the costs in EA's Operating and Maintenance expense application to IPART.

Current Insurance

Figure 2 – Annual Risk Premium Estimates under Current Insurance Arrangements



Claims Within Insurance Policy Deductibles

EnergyAustralia is currently insured for a number of risks. However, EnergyAustralia can still have a material exposure under its insurance policies since on most policies EnergyAustralia must pay an initial amount of any claim (the excess or deductible). Similarly, the insurance cover is limited and EnergyAustralia is liable for any claims costs above the limit. However, we have assumed that the likelihood of any such events is extremely low and so no allowance has been made for a claim to exceed the limit of insurance cover.

A review on EnergyAustralia's policy limits is outside the scope of this study.

TD has reviewed all EnergyAustralia's main insurance policies with respect to losses within deductibles, including:

- Bushfire liability insurance;
- Damage to substations of greater than $10m value; and
- Public and Products Liability insurance (excluding bushfire liability).

To calculate the risk premium estimates for deductibles we have used (for each component) the expected average claim size (capped at the size of the deductible) and the estimated claim frequency using EnergyAustralia's experience. Other allowances are made where appropriate, eg. in respect of public liability as a result of catastrophic bushfires.

Hardening of the Insurance Market

Insurance premium levels are cyclical and, prior to the events of September 11, were on the rise. Different market segments will see different trends in respect of future premium rates offered by the market. There are a number of contributing factors to this cycle. These factors include:

- The available capacity in the market (supply/demand);
- The availability and terms of reinsurance programs;
- The recent worldwide claims history;
- The current investment markets (in particular the bond market); and
- The current profitability of market segments.

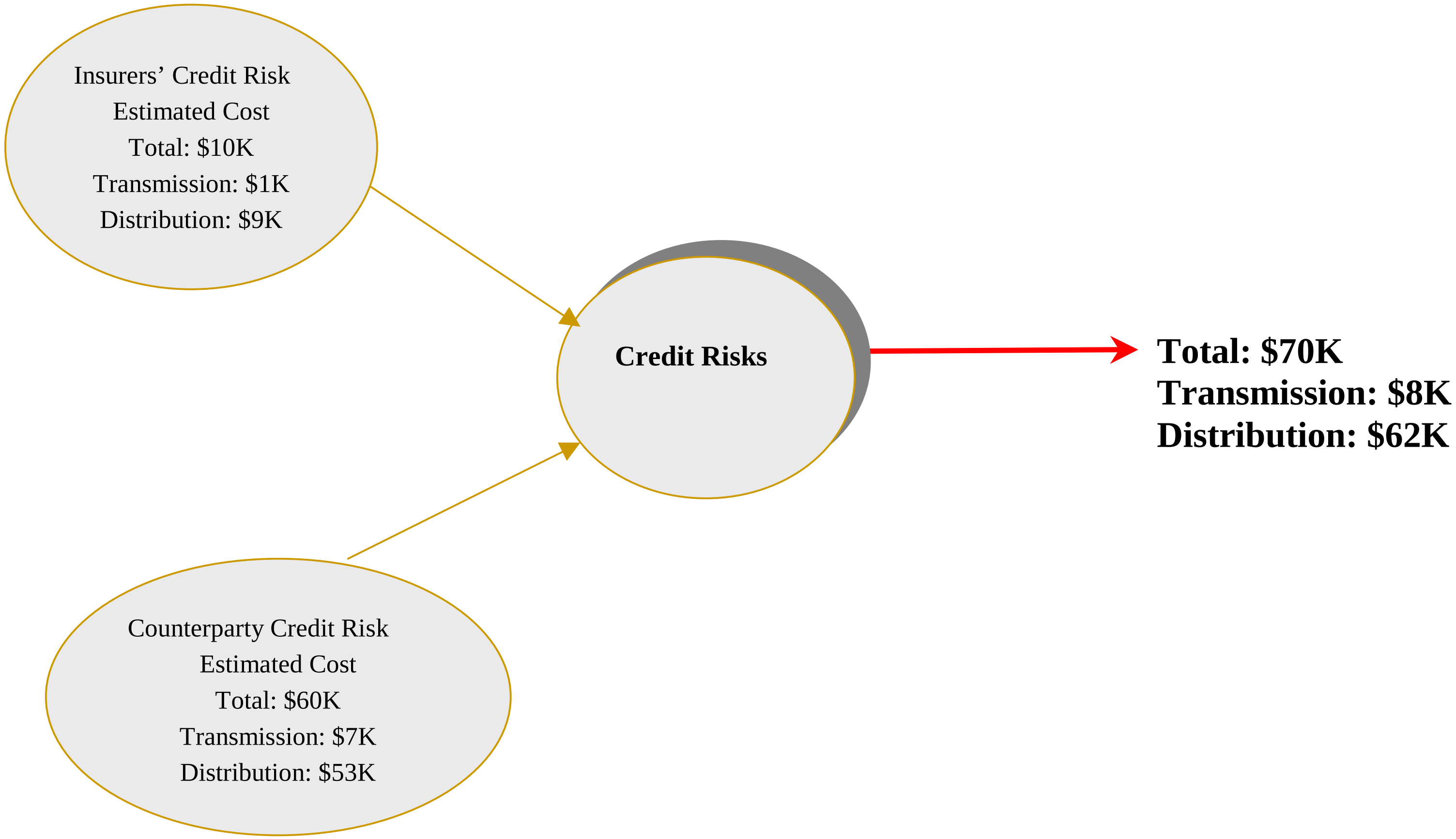
The tragedy of September 11 2001 has seen a fundamental shift in the insurance cycle. It will take time for the full impact to work through the insurance market. Current renewals have seen large increases to insurance premiums and reductions in the scope of cover provided. While further increases may be seen in the short-term it is difficult to assess what the likely long-term impact will be.

In Appendix A we discuss the impact of insurance market hardening in detail.

The outcome for insurance premium rates over the regulatory reset period is very difficult to assess at this point. The September 11 events will have a major long-term impact on the insurance market but it will be some time before the impact can be accurately assessed. Therefore we have not made any allowance in this report for a change in EnergyAustralia's insurance premiums over the regulatory reset period. However, we think that it would be reasonable to for EA to pass through any increases/decreases that they experience in their premiums as those changes will be outside their control.

Credit Risk

Figure 3 – Annual Risk Premium Estimates for Credit Risks



Insurers' Credit Risk

The risk faced by EnergyAustralia is related to the default risk of its insurers. This risk can be considered in terms of:

- Loss of Premium – the loss of the premium paid in respect to the unexpired period of cover; and
- Liability Exposure – in the event that an insurer is unable to honour an insurance policy, EnergyAustralia is exposed to any outstanding claims (including any incurred but not reported (IBNR) claims).

The probability of insurer default is based on a premium-weighted credit rating assumed to apply to all of EnergyAustralia's insurers. We estimate that the risk premium in respect of insurers' credit risk is $10,000 per annum. Based on EA's current transmission and distribution asset mix (12% of the assets are considered transmission assets), this annual premium can be segmented into $9,000 for EA's distribution assets and $1,000 for EA's transmission assets.

Counter party Credit Risk

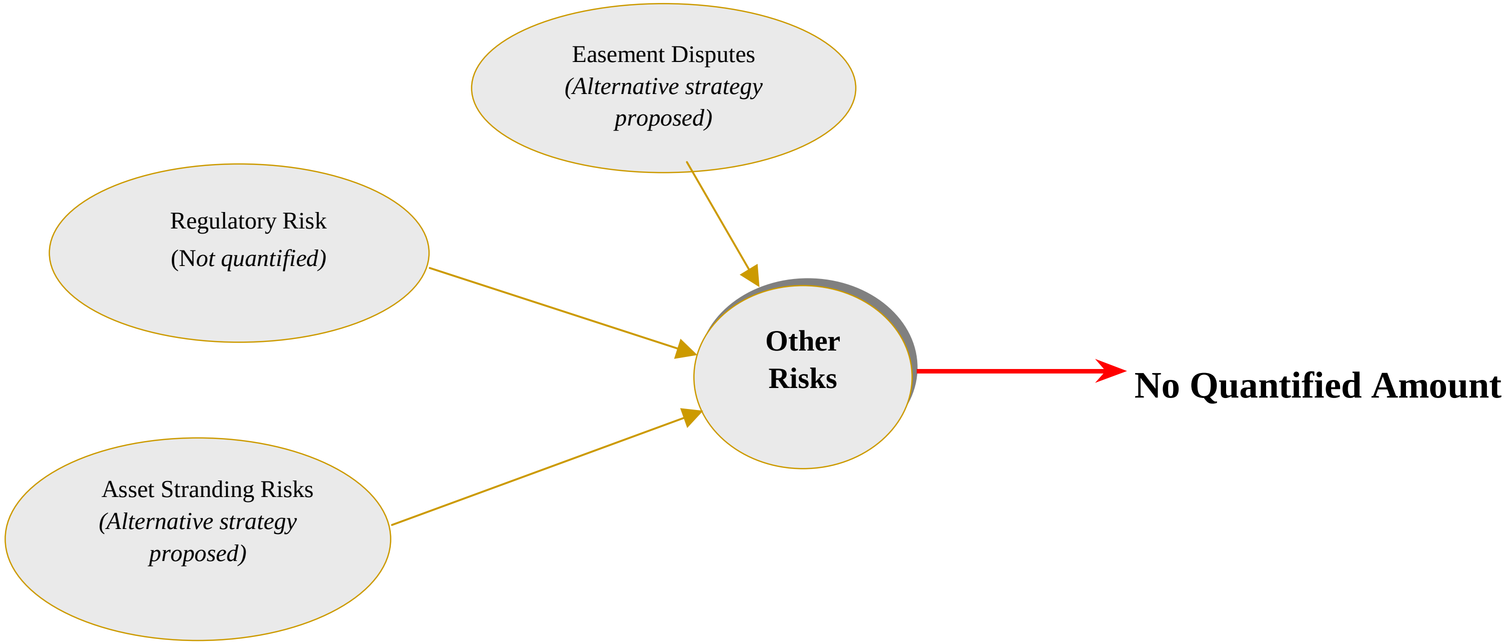
EnergyAustralia's revenue is received from retailers operating within the NSW Electricity market. A key risk for EnergyAustralia is counter party credit risk where a retailer defaults on the payment of distribution tariffs owed to EnergyAustralia. We have focused our risk analysis on the network revenue from EnergyAustralia's non-government owned customers only. In particular, we have focused on approximately 11% of total annual network revenues.

The revenues at risk in respect of these customers have been estimated by EnergyAustralia based on the current trading terms for these customers.

The probability of counter party default is based on revenue at risk weighted by a credit rating assumed to apply to all of EnergyAustralia's non-government owned customers. We estimate that the risk premium in respect of counter party credit risk is $60,000 per annum. Based on EA's current transmission and distribution asset mix, this annual premium can be segmented into $53,000 for EA's distribution assets and $7,000 for EA's transmission assets.

Other Risks

Figure 4 – Annual Risk Premium Estimates for Other Risks



Regulatory Risk

The potential cash flow impact of changes to the regulatory regime have not been considered in setting the EA's cost of capital (WACC) or cash flow projections. This regulatory risk can be regarded as a Non-Insured Event although it is not clear that this risk is diversifiable under a CAPM framework. In previous determinations Australian regulators have recognized the risks associated with the 'newness' of the regulatory regime by adding a premium to the WACC. Although regulators have since ceased to allow this premium we consider that the continuing evolution of the regulatory regime governing EA and the associated risk of regulatory 'shocks' still imposes real cost on EA.

The issue of regulatory risk is addressed in some detail in the Productivity Commission's 2000-01 Annual Report. The Commission argues that 'where long-lived investments are involved, the costs of regulatory error can be substantial'[6]. These costs are difficult to quantify and we have not attempted to estimate the expected cost of regulatory risk in this report. However, taking into account the capital base of the affected companies and the potential for regulatory risk to increase financing costs we believe this issue is significant and merits further consideration by IPART.

Asset Stranding Risk

Asset stranding risk represents the risk that EA's return of capital (in the form of depreciation) or revenue is less than expected because a higher than expected amount of assets are fully or partially stranded. For example, if a customer with dedicated distribution/transmission assets were to go out of business, then EA would lose future revenues associated with that customer and also potentially lose the depreciated value of that customer's dedicated distribution/transmission assets if those assets are "optimised" out of the regulated asset base.

Based on our discussions with EA, we understand that the total depreciated value of assets at risk of full or partial stranding due to business failure is about $8.6m. The largest of these assets at risk has a depreciated value of $2.4m. The bulk of these assets are associated with mining businesses.

[6] Productivity Commission Annual Report 2000-01, Chapter 1, p. 13

As the depreciated value of the assets at risk of stranding is small relative to the total value of EA's regulated asset base, we do not believe it is worthwhile to conduct a detailed investigation into the likelihood of EA experiencing asset stranding at a rate higher than expected. In our view, a reasonable way to approach stranded asset risks would be to adopt approaches similar to that undertaken by the ACCC and the ESC for the decisions for the Queensland Transmission Network Revenue Cap and for the Victorian Gas Distributors Revenue Cap. Our understanding is that these approaches effectively compensate the transmission or distribution company for asset stranding risk by either not stranding the asset or providing a depreciation allowance in respect of assets that are stranded.

Easement Disputes

We have calculated that the central estimate of the cost of easement disputes over the 5 year period of the regulatory reset is $9m. This figure supports the $10m Capex for the risk mitigation program to acquire easement gaps proposed by EnergyAustralia. This is because the $9m represents our central estimate of the cost of easement disputes whereas it is likely that the range in the cost of easement disputes is very large. Therefore, in our view, an allowance of $10m for risk mitigation appears to be reasonably prudent.

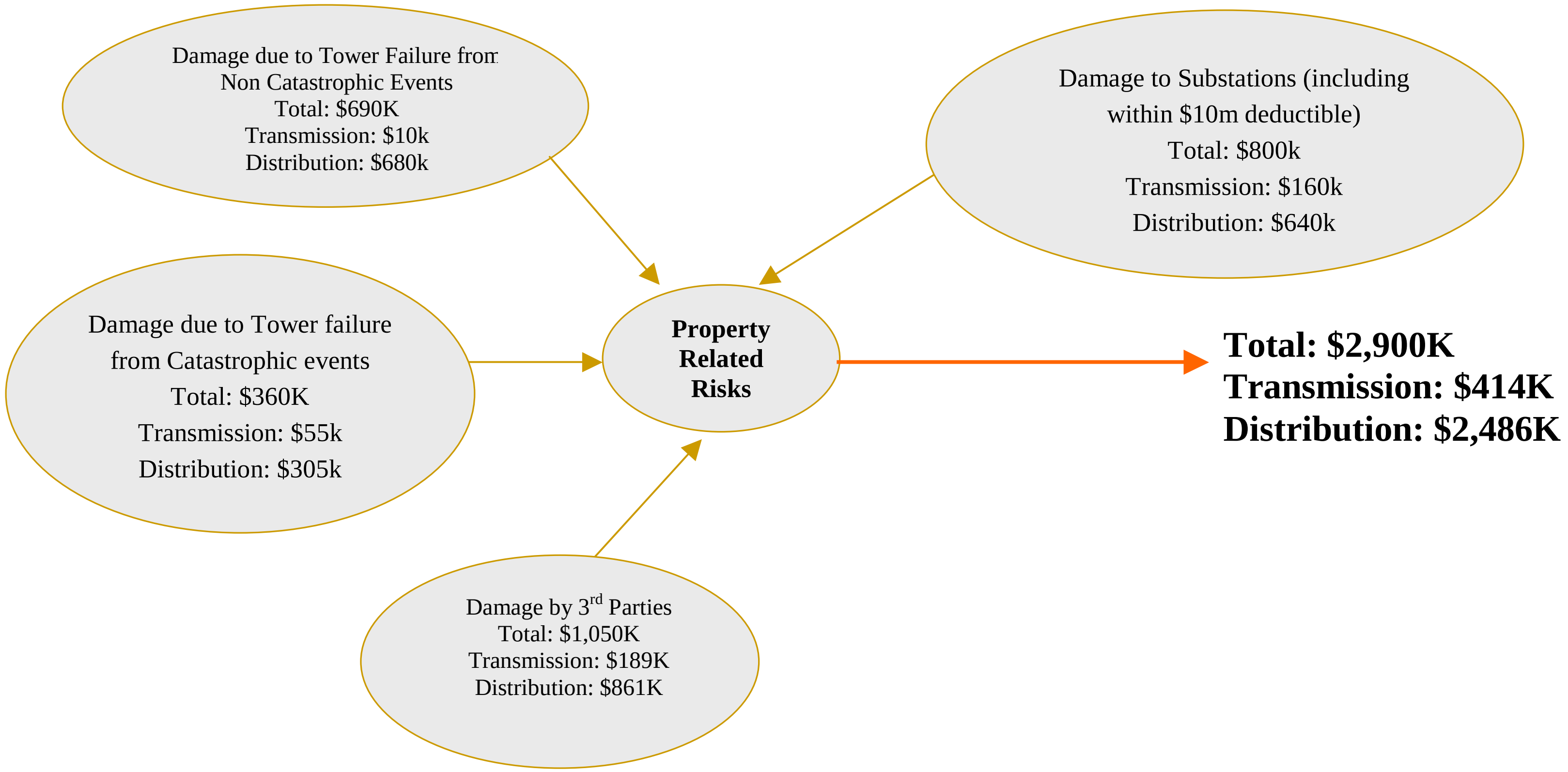
We believe that it is appropriate for EnergyAustralia to have a prudent capital expenditure program for this risk rather than attempt to forecast and pay for the cost of easement disputes.

Details of our estimation of the costs of potential easement disputes are included in a separate report titled "Valuation of Non-Insured Events, Confidential Documentation".

Part II Detailed Findings

1 Property Related Risks

Figure 1.1 – Annual Risk Premium Estimates for Property Related Risks



1.1 Property Damage to Towers and Wires

EnergyAustralia self-insures for property damage to its poles and wires.

General repairs and maintenance of towers and wires is a core component of EnergyAustralia’s operational expenditure. This expenditure would include costs associated with appraisals, preventive and corrective measures undertaken as part of the overall maintenance program. Further, we would expect that a base level of expenditure for repairs would be included in EnergyAustralia’s OPEX allowance to cover events that can be expected to occur regularly (for example, general storm damage).

We have identified four main perils which we believe pose a potential risk to EnergyAustralia’s tower and wires and for which a self-insurance premium should be allowed for in the regulatory reset.

- Failure of towers/poles (for example, due to termites, fungal decay and other non catastrophic causes)
- Impacts of severe storms
- Impacts of bushfires
- Impact of earthquakes

We consider the failure of towers/poles due to termites, fungal decay and other non-catastrophic causes separately to other perils at the end of this section of the report. Damage caused by third parties is included in the Section 1.3 of this report covering third party damage.

Self Insurance Risk Premium Estimate

The risk premium for self-insuring the towers and wires is calculated as:

Claim Size Per Tower Line km[7] * Incident Frequency of km Impacted Annually by each Peril

Claim Size Estimation

The replacement cost of a tower line depends on factors such as its voltage size, tower construction material and location. Cost per kilometre for a range of typical tower lines are included in the NSW Treasury's "Valuation of Electricity Network Assets. A Policy Guideline for NSW DNSPs, July 2001". EnergyAustralia has provided a breakdown of its asset base and Table 1.1 provides a summary of the potential replacement costs of different tower line categories. These costs are broadly consistent with those assumed in the NSW Treasury paper. We believe this average cost data provided is sufficient for the purposes of this study.

Table 1.1
Summary of Tower Line Costs

Description	Weighted Cost per km	% of Total EA km covered by Tower Class
	($000s)	%
132kV Tower Lines	193	4
66kV Tower Lines	84	2
32kV Tower Lines	82	6
11/22kV Tower Lines	34	37
Low Voltage Tower Lines	48	51

To provide a central estimate of the potential claim cost we have weighted the replacement cost per km for each tower line category by the % of total EnergyAustralia tower line kilometre covered by that category. While the failure risks associated with property damage

[7] Tower Lines consists of the towers/poles, wires, insulators and other components required to secure the wires as well as indirect costs including salaries, transportation, temporary replacement etc.

for some tower line categories may be higher than others we believe that using this simple weighting will provide a reasonable estimate for the average claim costs. The central estimate for the average claim cost calculated on this basis is $51,000 per km.

When tower lines collapse there are also additional indirect costs associated with these failures[8]. These include:

- Temporary replacement costs;
- Additional labour costs; and
- Plant or equipment hire.

To allow for these emergency costs we have included a 50% margin on the claim cost estimate per km. Our analysis is therefore based on a total average claim cost of a $75,000 per km.

Incident Frequency Estimation and Kilometres Impacted by Incidents.

Impact of Severe Storms

Catastrophic windstorms have the potential to cause major damage to EnergyAustralia's assets. In Appendix C we discuss the frequency of severe weather events in Australia.

Since 1994, EnergyAustralia's property has been impacted by approximately 12 severe storms. This has caused property damage to EnergyAustralia's tower lines and consequent business interruption losses to EnergyAustralia's customers. Table 1.2 summarises the effects of the 12 severe storms.

[8] While the NSW Treasury paper includes some indirect costs within the benchmark replacement costs we believe that under emergency situations these indirect costs are likely to be higher.

Table 1.2
Summary of 12 Severe Storms since 1994

Day and Date	Maximum Wind Gust (km/hr)	Customers Interrupted	Restoration Period (hours)
6th & 7th Nov 1994	135	45,000	60
20th Nov 1994	145	160,000	48
25th Sept 1995	101	92,000	30
30th & 31st Aug 1996	124	100,000	72
10th and 11th May 1997	85	50,000	30
24th Jan 1998	70	45,000	12
7th, 8th and 9th Aug 1998	120	110,000	60
15th Jan 2001	115	65,000	48
18th Jan 2001	100+	121,000	72
18th Aug 2001	100	40,000	18
19th Aug 2001	105	78,500	30
3rd Dec 2001	175	135,000	96

The damage caused by a severe storm can be localised or widespread. Based on discussions with EnergyAustralia officers, we have categorised the property damage caused by severe storms into two categories with differing incident frequency:

- 1 km of damage with an expected frequency of 1.5 incidents per year on average;
- 5km of damage with an expected frequency of 1 incident every 5 years.

We have therefore adopted an assumption for the weighted expected incidence of km damaged by severe storms as 2.5km per annum.

Bushfire Damage

Eastern Australia is prone to bushfires. Bushfires cause major damage to Australian property every year and continues to be a major concern to the community as a whole. Based on statistics that we obtained from the Fire Investigation Unit of the NSW Rural Fire Service, there were 365 fires[9] in NSW for the recent 2002/2003 fire season alone.

A fire in EnergyAustralia's distribution area does not necessarily result in damage to EnergyAustralia's towers and wires. However, there have been a number of incidents where EnergyAustralia's towers and wires have been damaged by bushfires. In Appendix C we discuss NSW bushfire risk in more detail.

The January 1994 bushfire caused severe damage to 4.5km of 132kV line, 3km of 33kV line, as well as 11kV and low voltage mains involving more than 100 poles[10]. 5 distribution substations and 17 pole transformers were also damaged or destroyed.[11] We also understand from discussions with EnergyAustralia that its assets have been damaged by the fires in more recent summers.

We have categorised the property damage caused by bushfires into two categories with differing incident frequency.

- 2 km of damage with an expected frequency of 1 incident every 5 years
- 15km of damage with an expected frequency of 1 incident every 10 years

We have therefore adopted an assumption for the weighted expected incidence of km damaged by bushfires as 1.9km per annum.

Earthquake

EnergyAustralia's assets are subject to the risk of major loss as a result of a catastrophic earthquake. Compared to countries located close to active tectonic zones Australia has a small earthquake hazard. However, earthquake hazard in Australia is real as demonstrated by the Newcastle earthquake of 1989. The Queensland University Advanced Centre for Earthquake Studies makes the following assessment,

[9] This statistic includes only those fires that were investigated.

[10] Based on a span length of at least 40m, this would equate to over 4km

[11] Joint Planning Committee, Pacific Power and Sydney Electricity, "January 1994 Bushfire Emergency"

> *"Australia is seismically active and earthquakes pose a substantial risk as demonstrated by the deadly magnitude 5.6 Newcastle earthquake of 1989. When compared to plate margin regions such as California or Japan, the rate of activity is lower, but relative to other intraplate regions, Australia's earthquake activity is moderate to high."*

In Appendix C we provide more information in regards to the earthquake risk in Australia.

Given the spread of EnergyAustralia's tower lines it is conceivable that if a significant earthquake were experienced within EnergyAustralia's distribution area that it would cause significant damage to EnergyAustralia's assets. While it is difficult to calculate an accurate incident rate, we have assumed the following scenario for our analysis.

- 40 km of damage[12] with an expected frequency of 1 incident every 100 years

We have therefore adopted an assumption for the weighted expected incidence of km damaged by earthquakes as 0.4km per annum.

[12] An earthquake causing damage within a 5km radius of the epicentre would cover a geographic area of over 75km^2. Within a 10km radius the geographic area would be over 300km^2.

Central Estimate

Table 1.3 shows our central estimate for the self-insurance of EnergyAustralia's tower lines.

Table 1.3 – Risk Premium Calculation

Cause	Cost per km[13]	Estimated km destroyed per annum	Risk Premium
	$000s/km	Km	$000s
Severe Storm	75	2.5	188
Bushfire	75	1.9	142
Earthquake	75	0.4	30
Central Estimate			360

Based on the current cost allocation for tower lines provided by EA we believe that it is reasonable to assume that 85% of the tower lines annual premium is relevant to EA's distribution assets with the remaining 15% being relevant to EA's transmission assets. This leads to an annual risk premium of $305,000 and $55,000 for EA's distribution and transmission assets respectively.

Failure of Towers/Poles (due to termite, fungal decay and other non catastrophic causes)

Apart from catastrophic perils, EnergyAustralia also has pole failures due to termite, fungal decay and other non catastrophic causes. Table 1.4 shows the recent history of tower failures due to these causes.

[13] Including additional indirect costs associated with emergency situations

Table 1.4
Recent History of Tower Failures

	Number of Pole Failures	% of Total Poles	Cause			
			Termite	Fungal	Termite & Fungal	Other
96-97	45	0.009%	13	21	7	4
97-98	57	0.012%	19	17	3	18
98-99	40	0.008%	15	12	10	3
99-00	37	0.007%	15	12	2	8
00-01	45	0.01%	11	14	6	14

We understand that the annual failure rates are consistent with industry standards at around 0.01%. For our analysis we have adopted an annual failure rate of 0.01%.

These events will generally impact on individual poles, particularly wooden poles. From discussion with EnergyAustralia's officers we estimate the cost to repair a single pole is approximately $10,000 to $15,000 which includes the cost of the pole, wires, other components and indirect costs of repair. While some poles are more expensive, for example those supporting larger wires, we understand that more expensive poles are less likely to be wooden and are less likely to fail. Thus we have used the conservative estimate of $12,500 per pole in our central estimate calculation. EnergyAustralia has around 550,000 wooden poles.

Table 1.5 shows the calculation of risk premium for tower failures due termites, fungal decay and other non catastrophic causes.

Table 1.5
Risk Premium for Tower Failures

Failure Rate	Number of Poles	Cost per Pole[14] ($000s)	Risk Premium ($000s)
0.01%	550,000	12.5	688

As table 1.4 shows, tower failures due to termites, fungal decay and other non catastrophic causes are fairly stable over time. EnergyAustralia may already have an allowance in its OPEX for these regular tower failures. In this instance, this risk premium calculation should be considering as supporting evidence of any OPEX allowance already made by EnergyAustralia.

Although most wooden poles are related to distribution assets, some transmission assets also have wooden poles. Based on the current cost allocation for wooden towers lines provided by EA we believe that it is reasonable to assume that 98.5% of the tower failure annual risk premium for non-catastrophic perils is relevant to EA's distribution assets with the remaining 1.5% being relevant to EA's transmission assets. This leads to an annual risk premium of $678,000 and $10,000 for EA's distribution and transmission assets respectively.

Summary

Table 1.6 summarises our estimate of the risk premium for EnergyAustralia's self-insured risk in regards to property damage of its towers and wires. This estimate covers the risk of tower damage excluding any consequential losses and third party damage.

[14] including replacement pole, wires, other components, staff salaries, other costs.

Table 1.6

Component	Distribution Asset Risk Premium (rounded)	Transmission Asset Risk Premium (rounded)	Total Risk Premium (rounded)
	$000s	$000s	$000s
Damage due to Catastrophic Perils	305	55	360
Damage due to termites, fungal decay and other non catastrophic causes[15]	680	10	690
Total	985	65	1,050

[15] Potentially included within OPEX allowance due to regular incidence of risk

1.2 Property Damage to Substations

As part of its regulated asset base EnergyAustralia has approximately 236 transformer substations. While EnergyAustralia has insurance which covers property damage to its substation valued at greater than $10m this insurance has a deductible of $10m. In effect EnergyAustralia self-insures for damage up to $10m.

General repairs and maintenance of substations is a core component of EnergyAustralia's operational expenditure. This expenditure would include costs associated with appraisals, preventive and corrective measures as part of the overall maintenance program. Further, we would expect that a base level of expenditure for repairs would be included in EnergyAustralia's OPEX allowance to cover events that can be expected to occur regularly.

However, EnergyAustralia also faces the risk of significant damage to its transformers and substations. Recent incidents where there is detailed information for the damages include:

- A transformer explosion and fire at the Paddington zone substation in November 2000, causing over $1 million of direct property damage costs.[16]
- A transformer explosion and fire at the Chatswood zone substation in December 1999, causing over $2 million of direct property damage costs.[17]
- Damage was caused to substations during the 1994 bushfires, where 5 distribution substations and 17 pole transformer substations were damaged or destroyed.[18]

We are also aware of other incidents that occurred prior to 1994, however detailed information regarding the damages arising from these incidents is not available.

[16] Report and Findings on "Paddington Zone Substation, Transformer Explosion and Fire", 7 December 2000

[17] Report and Findings on "Chatswood Zone Substation, Transformer Explosion and Fire", 9 February 2000

[18] Joint Planning Committee, Pacific Power and Sydney Electricity, "January 1994 Bushfire Emergency"

Self Insurance Risk Premium Estimate

The risk premium for self-insuring substation damage below the current $10m deductible is calculated as:

Claim Size Per Substation * Incident Rate of Damage per Substation * Number of Substations

Claim Size Estimation

EnergyAustralia's substations can be categorised into those with replacement cost less than $10m and those with replacement costs exceeding $10m. Table 1.7 shows a break down of the substations.

Table 1.7
Average Replacement Cost of Substations

Substation Size	Number of Substations	Average Replacement Cost of Transformer	Average Replacement Cost of Other Plant (including Buildings)	Average Total Replacement Cost
		($000s)	($000s)	($000s)
<10m	180	900	4,400	5,300
>10m	56	3,000	11,900	14,900

To estimated claim size per substation we have considered the information from the two most recent incidents as a starting point. Table 1.8 considers the costs associated with these incidents.

Table 1.8
Costs Associated with Most Recent Substation Incidents

Substation	Damage from Incident	Total Replacement Cost[19]	Damage as % of Total Replacement Cost
	($000s)	($000s)	(%)
Chatswood	2,000	7,120	28%
Paddington	1,000	5,639	18%

The data from these recent incidents illustrates the costs associated with incidents where partial damage to substation property has occurred. Neither case was considered a total loss. Total loss should be considered when estimating the expected future average claim cost. For example, while limited information is available on the bushfire event of 1994, 5 distribution substations were damaged or destroyed. We have therefore adopted an estimated claim cost of 35% of the total replacement cost, which reflects a combination of partial and full damage occurring from an incident.

Incident Frequency Estimation

The lack of historical claims data means that the estimation of an incident frequency involves qualitative judgement. Historically we are aware of 4 incidents since 1984, although 3 of these have occurred since 1994. This suggests a claim frequency of approximately 1 in 5 years. Given EnergyAustralia has around 236 substations, we calculate a claim frequency as

Number of Incidents/Number of Substations/Number of Years

giving an overall claim frequency of slightly under 0.1% (1 in 1000 years) per annum per substation. However, we also note that in the 1994 bushfire incident 5 distribution substations were damaged or destroyed from this one event, although we have limited data in relation to this event. This means the incident rate per substation per annum could be higher than 0.1%. We make no distinction between substations less than $10m and greater than $10m as we have no basis for considering more expensive substations as having a higher or lower likelihood of incidence.

[19] The transformer alone replacement cost is generally around 15% to 25% of the total replacement cost.

We have adopted an assumption for the expected incidence of substation damage of 0.125% per substation per annum.

Central Estimate

Table 1.9 shows our central estimate for the self-insurance of EnergyAustralia's substations.

Table 1.9 – Risk Premium Calculation

Substation Category	Incident Rate per Annum per Substation	Number of Substations	Average Replacement Cost	Average Claim Cost[20]	Risk Premium
	%		$000s	$000s	$000s
<$10m	0.125%	180	5,500	1,925	433
>$10m	0.125%	56	15,000	5,250	367
Central Estimate					800

Based on the current cost allocation for substations (including transformers) provided by EA we believe that it is reasonable to assume that 80% of the substation annual risk premium is relevant to EA's distribution assets with the remaining 20% being relevant to EA's transmission assets. This leads to an annual risk premium of $640,000 and $160,000 for EA's distribution and transmission assets respectively.

[20] While EnergyAustralia has insurance coverage for claims greater than $10m for substations worth greater than $10m, based on the assumptions we have adopted it would be extremely rare for the claims costs to exceed this $10m deductible.

1.3 Damage Caused by Third Parties

EnergyAustralia's network is the largest electricity distribution network in Australia. The EA network connects more than 1.4 million customers across a franchise area spanning about 22,300km^2. EA's network covers some of the most densely populated areas in New South Wales including the Sydney, Central Coast and Hunter regions. The expansive coverage of the EA network means that its network assets are exposed to potential damage from third parties. The damages would include both accidental damage and malicious damage to the network.

The following Table 1.10 provides a summary of the cost of third party damage to the EA network over the period 1 July 1998 to 30 June 2002.

Table 1.10 - Cost of Third Party Damage

Financial Year	1998/99	1999/00	2000/01	2001/02
Total Cost ($ '000)	2,612	3,238	3,112	2,563

The above values are based on the direct cost of materials and labour required to replace or repair the damaged network asset. In particular, the costs do not include any profit margin under the agreement between Enerserve (responsible for maintaining the network) and EA for the provision of network services. Therefore, the above third party damage costs may be understated. However, for the purpose of this report we have not made any adjustments to the above costs.

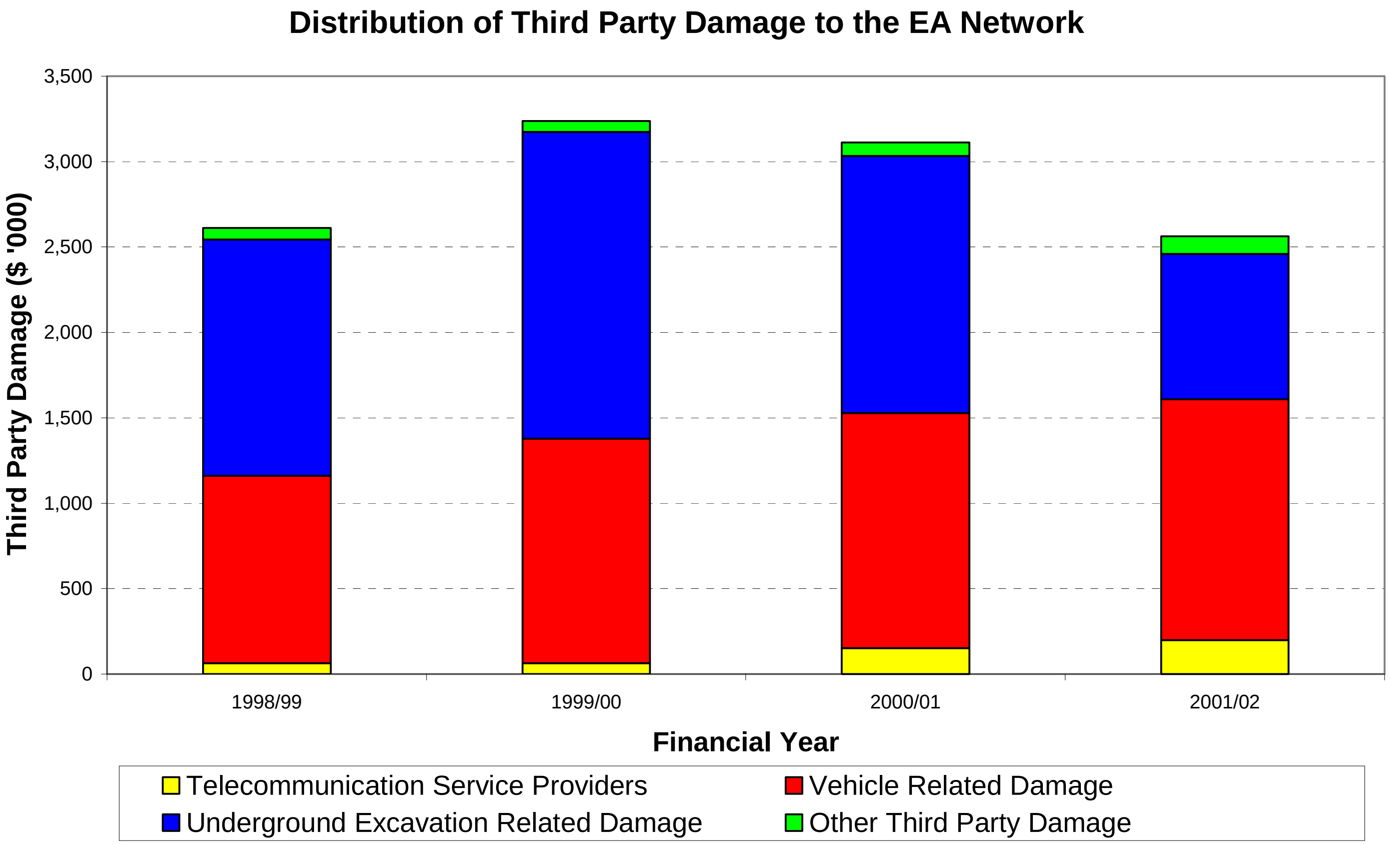
Further, we understand that the labour rates used to calculate the costs of third party damage are based on rates specified by IPART for the purposes of network cost recoveries by EA.

Analysis of EA historical third party damage data shows that about 93% of the damages are related to the following causes:

- Underground excavation resulting in damage to EA assets, especially underground powerlines;
- Vehicles coming into contact with EA assets, especially motor vehicles colliding into power poles.

Figure 1.2 shows the distribution of historical third party damage costs.

Figure 1.2 – Distribution of Third Party Damage



It is not meaningful given the available data to conduct a detailed analysis of the volatility of the annual cost from third party damage. However, EA and Enerserve officers involved with third party damage have advised us that the historical annual costs have been fairly stable within the range from $2-3 million pa. Further, EA and Enerserve officers have advised that they are not aware of any developments over the next regulatory period that would result in any significant changes to the drivers of third party network damage costs.

The total third party costs presented above do not represent the net cost to EA as some of the cost would be recovered by EA:

- Recoveries from the identified parties causing the damage; and
- Insurance recoveries. These have been negligible as EA's network assets are not insured for property damage[21].

Analysis of the historical data shows that EA has been able to identify and invoice about 68% of the costs from third party damage. Further analysis using invoice data covering the period from 1 July 1993 to 28 February 2003 shows that EA has achieved an average recovery rate of about 92% of total invoiced amounts.

Using the results of our analysis together with historical cost data over the period 1 July 1998 to 30 June 2002. Table 1.11 illustrates our calculation of the risk premium:

Table 1.11 – Calculation of Risk Premium Estimate

Financial Year	Third Party Damage Cost	Amount Invoiced	Average Recovery	Net Cost to EA
1998/99	$2,612,000	$1,396,000	$1,285,000	$1,327,000
1999/00	$3,238,000	$2,702,000	$2,486,000	$752,000
2000/01	$3,112,000	$2,306,000	$2,122,000	$990,000
2001/02	$2,563,000	$1,556,000	$1,432,000	$1,131,000

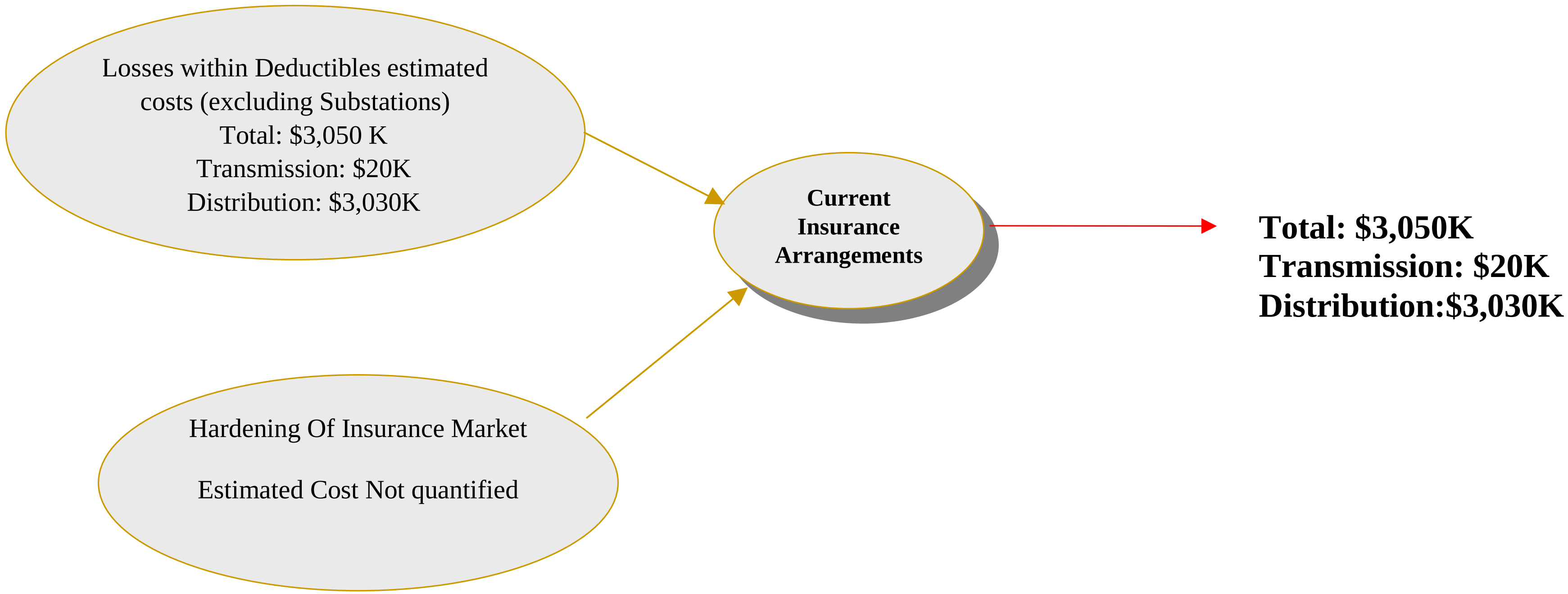
[21] With the exception of insurance cover for 56 high-value substations.

We estimate the annual risk premium in respect of unrecovered third party damage to the EA network is approximately $1,050,000 pa based on the average of the net cost to EA over the last four financial years. Based on damage report information provided by EA, this annual premium can be segmented into $861,000 for EA's distribution assets and $189,000 for EA's transmission assets.

We have been advised by EA that the unrecovered costs are not allowed for through any regulatory mechanisms including the inclusion of the costs in EA's Operating and Maintenance expense application to IPART.

2 Current Insurance

Figure 2.1 – Annual Risk Premium Estimates under Current Insurance Arrangements



2.1 Claims Within Insurance Policy Deductibles

Although EnergyAustralia insures itself against a number of risks, it is still exposed to potential claim-related costs because most of the insurance coverage includes an excess or deductible. This means that EnergyAustralia is required to pay the first portion of any claim.

Further, EnergyAustralia is covered to the extent of any insurance limit. This means that there is potential for EnergyAustralia to exhaust its cover and any claims cost in excess of the limit fall back on EnergyAustralia. However, we have assumed that the probability of exhaustion of the policy limits is low. Although scenarios could be constructed, we have not quantified the impact, as the low assumed likelihood of these events makes it hard to justify an allowance.

Notwithstanding that no allowance has been made, EnergyAustralia should be aware that the risk is real. Recent events including the Longford incident and the Auckland blackout show that while these events are extremely rare they can occur. Consideration of the risk to EnergyAustralia from catastrophic risks may involve a review of current insurance arrangements and in particular the limits of liability. Such a review is outside the scope of this study.

Current Deductibles

There are a number of reasons why deductibles are generally included in policies. These include:

- The sharing of the risk to encourage better risk management;
- To reduce an insurer’s exposure to small claims which are relatively expensive (as percentage of claim size) to administer; or
- The premium reduction more than offsets the expected costs of claims within the deductible.

We have based our calculations on the following deductibles:

- A $50,000 deductible per claim for Public Liability claims (includes claims such as bodily injury and property damage);
- A $10m deductible per claim for bushfire liability claims;

- A $10m deductible for substations that are valued in excess of $10m;

Deductibles Summary

Table 2.1 summarises the expected total cost of claims, and the expected costs of claims relevant to EA's transmission and distribution assets within EnergyAustralia's insurance policy deductibles:

Table 2.1 –Expected Cost of Claims within Deductibles

Category	Risk Premium Estimate ($000 p.a.)	Transmission ($000 p.a.)	Distribution ($000 p.a.)
Public Liability Claims	$2,646	$0	$2,646
Bushfire Liability Claims	$400	$20	$380
Substation Damage	Please refer to section 1.2	Please refer to section 1.2	Please refer to section 1.2
Total	**$3,046**	**$20**	**$3,026**

Bushfire Liability Risks

Bushfire liability risk represents the risk that liabilities arise for EA as a result of bodily harm or damage to property caused by a bushfire that is ignited by EA's assets. Note that bushfire liability damages does not include any damages to EA's assets. EnergyAustralia's historical experience of bushfire liabilities since 1990 is shown in Table 2.2 below.

Table 2.2

Year	Number of Claims	Bushfire Liability Incurred
1990	1	$2.21m
1994	1	$0.17m
1995	1	$0.00m*

*Note that this claim was notified but has not had any claim payments to date.

Recently, we understand that Integral has incurred bushfire liabilities in the order of $10m in respect of the bushfires occurring in December 2001.

In arriving at a central estimate of EA's future bushfire liabilities, we believe that there may be issues with simply taking the historical average of EA's past experience of bushfire liabilities. Some reasons are as follows:

- Due to the nature of the risk (very few claims but potentially very high damages), EA's claims history is sparse. Therefore taking the average of past bushfire liability claims may not reasonably represent the future bushfire liability risk;
- Changing bushfire mitigation strategies may mean that future bushfire risks differ from those in the past;
- Future damage from bushfires may be significantly different from past damage due to:
    - An increased or decreased number of households living in areas at risk of bushfires;
    - Different building practices for households in areas at risk of bushfires to reduce fire damage.

To estimate the future bushfire liability for EnergyAustralia, we have separately considered the likely future incident rate for bushfire liability incidents and the likely damages caused by bushfires.

Future Incidence of Bushfires in EA's Distribution Area

In order to estimate the future incidence rate of bushfires in EA's distribution area we have investigated the following:

- The historical rate of bushfires in EA's distribution area;
- The proportion of bushfires caused by utilities in NSW, Victoria and in America;
- The changes that EA has made to their bushfire mitigation strategy and the likely reduction of bushfire liabilities as a result;
- The chance that the period 2004 to 2009 will be subject to higher than expected drought conditions.

Historical Rate of Bushfire Liability Incidents in EA's Distribution Area

The two sources of historical information that we received for the rate of bushfires in EA's area are:

- Statistics from the Electricity Supply Industry Group Insurance Scheme that shows the number and severity of Bushfire liability incidents for EA and other NSW distributors for the period 1991 to 2002;
- Statistics regarding NSW Bushfire Incidents from the Electricity Association of NSW data for the period 1990-2000.

The statistics from the Electricity Supply Industry Group Insurance Scheme show that:

- EnergyAustralia has had 3 bushfire liability incidents in the last 12 years;
- NSW electricity distributors have had 27 bushfire liability incidents in the last 12 years (including the recently reported $10m bushfire claim in respect of the Christmas 2001 bushfires for Integral Energy).

Our understanding of the above data is that only bushfire incidents that resulted in a liability (or at least initially expected to result in liability) are reported to the group insurance scheme.

The statistics from the Electricity Association of NSW show the number of bushfire incidents in NSW split by cause for the period 1990 to 2000. Table 2.3 below shows these statistics:

Table 2.3

Cause	Further Description of Cause	Number of Bushfires
Conductors clashing/trees/wind/top onto bottom layer	Conductor Clashing	22
	Tree	50
	Wind/Storm	19
	Miscellaneous	5
Neutral/Conductor failure/Loose line clamp		32
Pole/Cross-arm failure		28
Bird/Animal		29

Cause	Further Description of Cause	Number of Bushfires
Pollution of Line	Pole-top Fire	4
	Cross-arm Fire	5
	Dirty Insulators	11
	Pollution on Line	6
Third part person/Vehicle hit distributor property (e.g. poles, substations or lines)		25
Insulator tie failure		24
Fuse failure		25
Lightning		11
Incorrect connection/disconnection		6
Power lines down or low hanging/conductors striking ground		5
Employee/equipment damaged 3rd party property whilst doing repairs		3
Transformer fault		3
Circuit breaker failure		1
Total		**314**

Note that the Electricity Association of NSW has 314 bushfire liability incidents between 1990 and 2000 whereas the Electricity Supply Industry Group Insurance Scheme has 26 bushfire liability incidents between 1991 and 2002. The reason for this difference is that the incidents recorded by the Electricity Association of NSW includes all bushfires caused by electricity assets whether they resulted in a liability or not whereas the incidents recorded by the Group Insurance Scheme are limited to those that resulted in a liability.

Our understanding is that the information in the Table 2.3 is not available by the separate electricity distributors. Thus, whilst the table provides useful information about the bushfire liability experience of NSW, it does not provide us with information specific to EA.

However, the table does help determine the maximum possible improvement that bushfire mitigation strategies could achieve (this is discussed in greater length in a subsequent section).

In conclusion, the information that we have obtained from the reports provide some support for us to determine a bushfire incident rate for EA with the principal observations being:

- EnergyAustralia had 3 liability incidents in the 11 year period. However, one of these liability incidents did not result in a loss for EnergyAustralia.
- The number of incidents could be understated because some claims may have been incurred but not yet reported. For example, there may be a delay between when a bushfire occurs and the determination of the exact cause of the bushfire.

Proportion of Bushfires Caused by Electricity Assets

To help establish a reasonable incidence rate for bushfires caused by electricity assets, we investigated the proportion of bushfires caused by electricity assets in NSW, Victoria and the United States.

Based on statistics that we obtained from the Fire Investigation Unit of the NSW Rural Fire Service, the causes of bushfires (for the fires investigated) in NSW for the recent fire season (2002/2003 fire season) are shown in Table 2.4 below.

Table 2.4

Cause	Number of Fires	Percentage of Fires
Deliberate Ignitions	224	61.3%
Burning Activity	25	6.8%
Campfire/BBQ	8	2.1%
Electrical/Power Lines	19	5.2%
Lightning	62	16.9%
Machinery/Equipment	10	2.7%
Spot Fires/Re-ignitions	9	2.5%
Undetermined	8	2.1%
Total	**365**	**100%**

From Table 2.4, we can see that 19 fires were caused by electricity assets which represents 5.2% of all the fires that were caused. However, we note that there are some limitations associated with the figures in the table, which are:

- The table shows figures for only one fire season which may not be representative of the underlying causes and incidence rates. Based on our discussions with the NSW Rural Fire Service, we understand that no similar statistics are available for previous fire seasons; and
- The fires shown in the above table only represent a small portion of those occurring in NSW in the previous fire season. The fires shown in the above table are those that meet the criteria for police investigation.

Given the above limitations, the figure of 19 fires is broadly consistent with the annual number of fires suggested by the data from the Electricity Association of NSW where there were 314 fires over 11 years or an average of 29 fires per year.

The following Table 2.5 illustrates Victoria's experience with respect to the number and causes of bushfires for the period 1976/77 to 1995/96:

Table 2.5

Cause	Number of Fires	Percentage
Lightning Strikes	3024	25.9%
Deliberate Lighting	2499	21.4%
Escapes – burning	2098	18.0%
Escapes – campfire, BBQ	1109	9.5%
Departmental burns	232	2.0%
Trains and Power Transmission	224	1.9%
Machines	296	2.5%
Pipe, Cigarette, Match	913	7.8%
Miscellaneous	596	5.1%
Unspecified	685	5.9%
Total	**11,676**	**100.0%**

Our main observations from the above table is that:

- About 2% of fires were caused by trains or power transmission; and
- About 10 fires a year are caused by trains or power transmission in Victoria.

Statistics from the California Department of Forestry and Fire Protection showed that 155 bushfires caused by power lines occurred in California in 1998. This figure represents 3% of the fires that occurred in California in that year.

Our conclusion from the examination of broader NSW experience, Victorian and United States experience is that the fire incidence rates in NSW suggested by the data we obtained from EA do not appear to be unreasonable. However, we note that the data is not directly comparable and there is limited data with which to make comparisons.

EA's Bushfire Mitigation Strategy

We have had numerous discussions with officers of EA in relation to the bushfire mitigation strategies that are in place. In particular, our conversations were focussed on whether current bushfire mitigation strategies are different to those in the past in order to help us form a view as to whether the current strategies would reduce future bushfire risks.

Based on our discussions, the differences between bushfire practices for the two most recent fire seasons and those of the past include:

- New bushfire risk maps - these maps show for any point on land, the estimated bushfire risk based on vegetation type, slope angle and aspect. As these bushfire maps can be combined with maps of EA's assets, they have helped EA to improve the planning of their inspection and maintenance programs;
- Greater notification of customer's responsibilities with respect to the maintenance of private power lines - for example, it is the customer's responsibility to ensure that private power lines are clear of vegetation;
- New overhead mains construction standards - these new standards are expected to reduce bushfire risks;
- Implementation of the NAMS database - This database records inspection and maintenance activities. EA have advised us that the database makes it possible to have a greater degree of management efficiency and organisation with respect to ensuring bushfire mitigation policies are carried out properly;
- Phasing out of bonds or connectors that are deemed to have an unacceptable bushfire risk;
- Installation of additional mid-span spreaders for low voltage lines;
- Changing the auto and non-auto reclosing of powerlines in rural areas. There will now be a greater number of electricity assets set to non-auto with respect to reclosing. When a power line is non-auto it means that the current will be cut off after an incident where a fault is detected (an example of a fault may be where a power line is in contact with a branch for a significant amount of time) and will not switch back on automatically. That is, a manual inspection of what caused the fault will take place prior to the power being restored. When a line is auto, power is restored automatically after a certain amount of time.

EA expect that these new policies will significantly reduce bushfire risks and in our view this assertion appears to be reasonable. However, based on the statistics provided by the Electricity Association of NSW in Table 2.3, EA have also advised us that the proportion of fires preventable by improved maintenance procedures account for about one third of all fires caused by electricity assets. Thus, even if every possible precaution were taken, two thirds of bushfires would still occur. Finally, as the new procedures have only been in place for one or two fire seasons, it is difficult to quantify the likely improvement as a result of the new policies.

In conclusion, it is likely that the new bushfire mitigation strategies will reduce the risk of bushfires occurring. However, it is difficult to quantify the likely reduction in bushfire incidence with a high degree of accuracy.

Possibility of Drought Conditions in the Future

Clearly, a major factor that impacts on future bushfire incidence and severity is the likely drought conditions over the regulatory period. Based on information from CSIRO's website and our prior discussions with CSIRO, our understanding is that it is difficult to forecast the possibility of drought conditions over a 5 year time horizon with a reasonable degree of accuracy. Therefore, it is not possible to predict whether it is more likely that there will be worse than average drought conditions during the forthcoming regulatory period.

Estimated Frequency of Bushfires Caused by EA

In our view, the likely future frequency of bushfire liability incidents caused by EA is difficult to predict with a high degree of certainty due to the nature of bushfire risk. We believe that a reasonable range for the average annual number of bushfire liability incidents caused by EA to be between 0.15 and 0.4 fires per year (note, this figure represents bushfires that lead to liability). In our view, the key factors to consider in determining a central estimate for the incidence rate are as follows:

- Based on historical experience of bushfire liability incidents for EA, the annual incidence rate for bushfire liability incidents is about 0.23 (or 0.15 if we do not include one of the claims which was reported but did not result in liability). However, this incidence rate is only based on 3 claims so it is highly uncertain.
- It is likely that the new bushfire mitigation strategies will reduce the risk of bushfires occurring. The likely maximum impact of the new bushfire mitigation strategies is to reduce bushfire incidence rates by a third. However, it is probably unrealistic to expect such a large improvement.
- There may be bushfire liability incidents that have claims that are incurred but not yet reported.

After consideration of the above factors, we believe that a reasonable central estimate for the number of bushfire liability incidents caused by EA is 0.25 per year.

Severity of Bushfire Liability

In order to estimate the future severity of bushfires in EA's distribution area we have investigated a study by Bruce Malamaud et al. on the distribution of bushfire severity.

Distribution of Areas Affected by Bushfires

A study in 1998 by Bruce Malamaud, Gleb Morein and Donald Turcotte of Cornell University[22] in the United States included the consideration of the typical size of a forest fire. The conclusion from this aspect of the study was that the area burnt by a bushfire in the 4284 observed fires on US Fish and Wildlife Service land between 1986 and 1995 strongly follows a power law. That is, for each doubling of the area of a fire, the frequency of occurrence reduces by a factor of 2.48. The study also found that the same power law appears to be relevant to Australia and presumably other parts of the world.

In our view, if the area of land burnt by a bushfire follows a power law, than it is reasonable to assume that the public liability damage caused by a bushfire also follows a power law.

Estimated Severity of Damage Caused by Bushfires

To estimate the distribution of the severity of bushfire claims, we fitted the bushfire liability claims data to a Pareto distribution. Table 2.6 below summarises the claims data that we used to fit the distribution:

[22] B. Malamaud, G. Morein and D. Turcotte, Forest Fires: an example of self-organised critical behaviour. *Science* 1998; 281: 1840-2.

Table 2.6

Lower Bound of Claim Size	Upper Bound of Claim Size	Historically Observed Number of Claims
400	10,000	7
10,000	50,000	5
50,000	150,000	6
150,000	500,000	5
500,000	Infinity	4
	Total	**27**

In our view, the fitted Pareto distribution is broadly reasonable, our key observations about the fitted Pareto distribution are as follows:

- When compared to the actual claims experience, the fitted Pareto distribution appears to:
  - Overestimate the number of small and large bushfire liability incidents that occurs (that is, the number of claims under $10,000 and over $500,000 appear to be overestimated).
  - Underestimate the number of claims for bushfire liability incidents costing between ($10,000 and $500,000).
  - However, we note that there is very little data with which to fit the distribution and to check whether the fit is appropriate.
- The fitted Pareto curve appears to be in line with the results of the study by Bruce Malamaud, Gleb Morein and Donald Turcotte. That is, based on the fitted distribution a bushfire liability claim that is twice as large is 2.3 times as rare. This compares reasonably well with results of the study which concluded that a bushfire that burns an area twice as large is 2.48 times as rare.

Based on the fitted Pareto distribution, the average cost of a bushfire liability incident is $1.6m. This average cost allows for the bushfire liability deductible of $10m after which the cost of the event is insured.

Please refer to Appendix D for more detail regarding our work to fit the Pareto distribution.

Estimated Risk Premium

Our estimated incidence rate for bushfire liability incidents for EA is 0.25 incidents per year. We have estimated that the average claim size (under the current insurance policy deductible of $10m) for bushfire liability incidents to be $1.6m. Based on these estimates, the annual risk premium for bushfire liability risks for EA is $400,000. This estimate is based on:

- Available data; and
- Previous studies on bushfire dynamics.

In our view the $400,000 estimate represents a reasonable estimate of the mean cost of bushfire liability claims. However, due to the nature of bushfire risks, it is not unlikely that future annual experience and indeed the average experience over the next regulatory period will differ from the estimated average.

Based on discussions with EA we believe that it is reasonable to assume that 95% of the future bushfire liability annual premium is relevant to EA's distribution assets with the remaining 5% being relevant to EA's transmission assets. This conclusion was reached because EA has much fewer transmission assets than distribution assets and transmission assets have more stringent bushfire prevention standards. This conclusion leads to an annual risk premium of $20,000 and $380,000 for EA's transmission and distribution assets respectively.

Public Liability Estimate of Risk Premium

We have estimated EA's annual risk premium for public liability claims to be $2.65m per year expressed in 2006/2007 dollars. We have expressed our results in these dollars because for certain types of claims, the effects of inflation are substantial and hence, in our view, it is appropriate to express risk premiums in dollars as at the mid-point of the next regulatory period. In making this estimate, we have considered the following key factors:

- EA's historical experience;
- Trends in that experience;
- The effect of the NSW Civil Liability Act 2002; and
- The future deductible will increase to $50,000 per claim from its current level of $20,000. This increase is based on EA's expectation of the insurance renewal terms. In our view, this expectation is reasonable because the current level of deductible was negotiated prior to the September 11 tragedy and it is most likely that insurance coverage will reduce when the policy is renegotiated in September this year.

Based on our discussions with EA, we understand that all (or almost all) or their historical claims were related to their distribution assets. Therefore, we have assumed that all future public liability claims are relevant to EA's distribution assets.

Note that the estimates in the above table do not include allowances for legal expenses and claims handling costs for public liability claims. In our view, these costs are necessarily incurred in the course of conducting EA's business and as such EA should be compensated for them appropriately. We have not attempted to quantify an appropriate level of legal expenses or claim handling expenses for EA but note that:

- Historically legal expenses for settled claims have accounted for approximately 3.5% of total claim amounts. Note that based on our experience, legal expenses are typically significantly higher than this; and
- An allowance of between 5% and 10% of total claim amounts for claims handling expenses would represent a "standard" loading for an insurer. However, as EA is not an insurer, these figures serve only as a broad guideline for what might be a reasonable expense loading.

In addition, in our estimate of the future risk premium we have made an allowance for:

- Potential future claims inflation, for bodily injury claims we have adopted an inflation rate of 8% which consists of 4% inflation due to future assumed AWE inflation and 4% superimposed inflation (which represents our experience of how claims of this nature increase at a rate greater than inflation). For all other types of claims, we have adopted an inflation rate of 3% which is our assumed future CPI inflation rate.
- The delay between when a claim is incurred and when payments in respect of that claim are made. We have discounted future claim payments to the year in which they were incurred at our assumed future risk free discount rate of 4.75%. In our view, based on current government bond yields for the duration relevant to these claims, a discount rate of 4.75% is reasonable.

For more detail regarding our estimation of a risk premium for public liability claims, please refer to Appendix E.

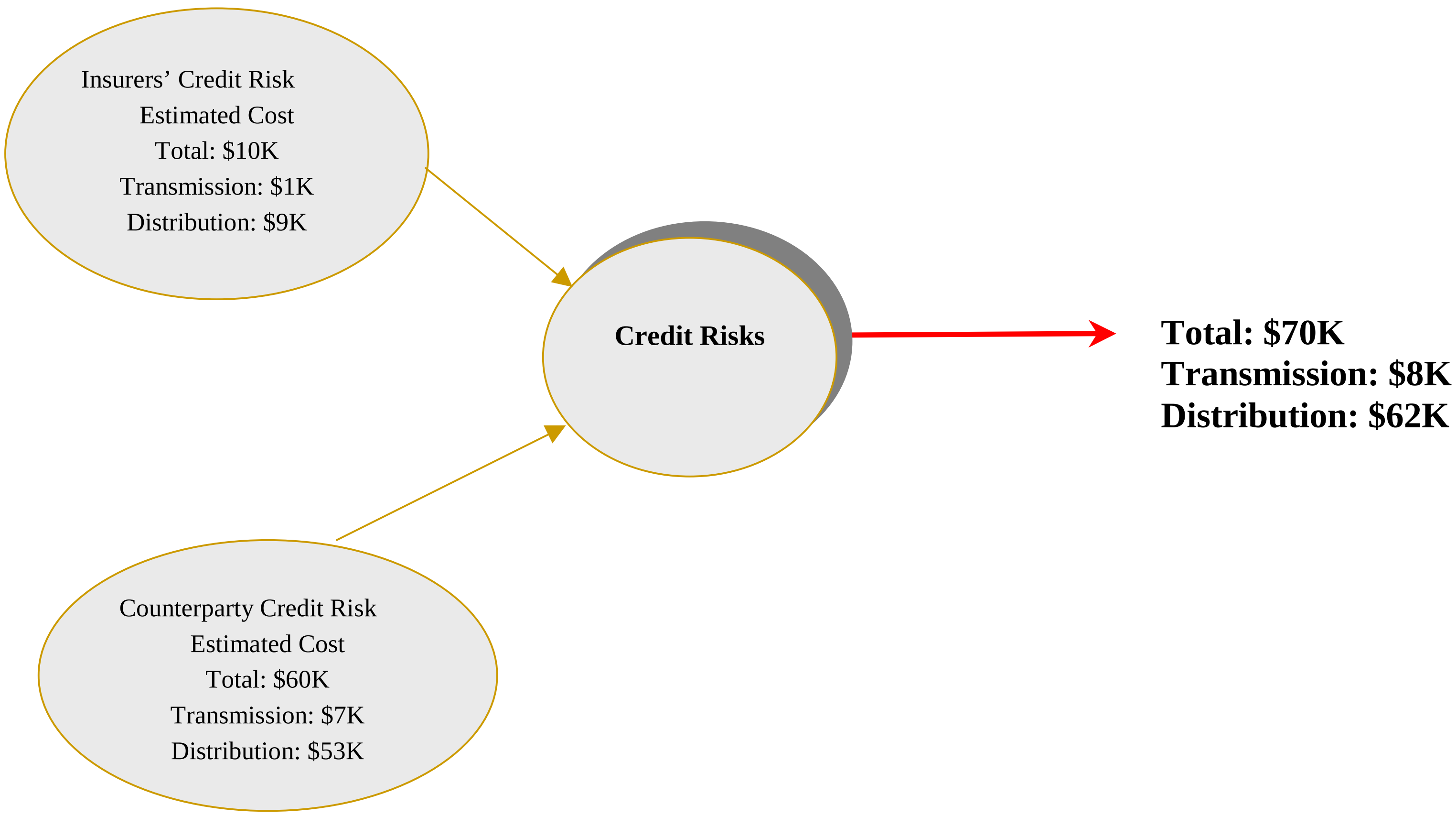
2.2 Hardening of the Insurance Market

In Appendix A, we discuss the impact on insurance premiums of the cyclical nature of the insurance market. Prior to the September 11 terrorist attacks, premiums were on the rise. The September 11 events have resulted in a fundamental shift in the insurance cycle. It will take time for the full impact to work through the insurance cycle. Current renewals have seen large increases to insurance premiums.

The outcome for insurance premium rates over the regulatory reset period is very difficult to assess at this point. The September 11 events will have a major long-term impact on the insurance market but it will be some time before the impact can be fully assessed. Therefore we have not made any allowance in this report for a change in EnergyAustralia’s insurance premiums over the regulatory reset period. However, we think that it would be reasonable to for EA to pass through any increases/decreases to their premiums, since such changes will be outside the control of EA.

3 Credit Risk

Figure 3.1 – Annual Risk Premium Estimates for Credit Risks



3.1 Insurers' Credit Risk

We have based our calculation of the risk premium to cover insurer default on an annual insurance cost of about $6 million; based on EnergyAustralia's insurance premiums for the 2002/03 year.

The risk faced by EnergyAustralia is related to the default risk of its insurers. This risk can be considered in terms of:

- Loss of Premium – the loss of the premium paid in respect to the unexpired period of cover; and
- Liability Exposure – in the event that an insurer is unable to honour an insurance policy, EnergyAustralia is exposed to any outstanding claims (including any incurred but not reported (IBNR) claims).

Recently, the HIH collapse in Australia left thousands of policyholders with unpaid claims. We understand that as a result of the HIH collapse, EnergyAustralia was left without insurance cover for product and public liability claims incurred in the past that will be settled in the future. This is because these types of insurance policies are traditionally written on an "occurrence" basis, where an insured event that occurred during the year of coverage is met from that year's policy, even if the claim is made many years into the future.

In estimating the Loss of Premium risk, we have assumed that bankruptcies occur mid-way through the year; therefore the amount at risk is $3 million and not the full $6 million.

Assuming appropriate pricing by the insurers the central estimate of the cost of EnergyAustralia's exposure to uninsured liabilities will be lower than the premium charged. This is because the insurer adds a margin to the risk premium to cover expenses and profit. The insurer also gains the benefit on investment for the period between receiving premium and paying claims. Allowing for these offsetting factors we have estimated a liability exposure risk of $3 million (again assuming mid-year failure and no recovery). We have not allowed for claims incurred prior to the year of the insurer's default that had not been fully paid by the date of default.

The probability of occurrence is based on an assumed average credit rating for the insurers.

The following Table 3.1 summarises the results of our analysis:

Table 3.1 – Results Summary

Loss Scenario	Amount at Risk ($ '000)	Probability of Occurrence	Risk Premium ($ '000)
Loss of Premiums	3,000	0.00125	3.8
Liability Exposure	3,000	0.00125	3.8
Total			**7.6**

We estimate that the risk premium in respect of insurers' credit risk is about $10,000 per annum. Based on EA's current transmission and distribution asset mix (12% of the assets are considered transmission assets), this annual premium can be segmented into $9,000 for EA's distribution assets and $1,000 for EA's transmission assets. We have adopted this simple approach due to the materiality of the total risk premium.

The risk premiums are small, but are subject to considerable volatility. There is potential for EnergyAustralia to be exposed to millions of dollars of uninsured losses if insurer failure occurs at a time when EnergyAustralia has significant outstanding claims. We have assumed no correlation between these events, reducing the annual risk premium to small levels.

3.2 Counter Party Credit Risk

EnergyAustralia's revenue is received from retailers operating within the New South Wales electricity market. A key risk for EnergyAustralia is counter party credit risk where a retailer defaults on the payment of distribution tariffs owed to EnergyAustralia. About half of EnergyAustralia's revenue is currently received from government-owned retailers[23], with the remainder sourced from smaller privately/publicly owned retailers. This situation may change as full retail contestability (FRC) evolves in NSW.

[23] This excludes revenue from EnergyAustralia's retail business.

Retailing in the NSW electricity market is a low margin, high-risk business and there is the potential for retailers to default on payments or go out of business. Retailers do not have a material asset base (after ring-fencing from distribution business). Further, the introduction of FRC has added further uncertainty to the market. New retailers will potentially enter the market with a higher risk of default either through a less established business framework or the need to cut margins and reduce profitability to build market share and business mass. An example in the telecommunications industry was the collapse of One.Tel.

For the purpose of analysing EnergyAustralia's exposure to counter-party risk, we have assumed that the probability of default by government-owned retailers is negligible and have focused our analysis on the revenue from the privately/publicly owned retailers. In particular, we have focused on approximately 11% of total current annual network revenues.

EnergyAustralia has provided the average and potential maximum outstanding amounts in respect of the privately owned retailers based on the current trading terms with these retailers. We make no allowance for the seasonal variation of revenue.

The probability of counter party default is based on revenue at risk weighted credit rating assumed to apply to all of EnergyAustralia's non-government owned customers. We have estimated a weighted credit rating of BBB. We assume default is equally likely any point during the year.

Table 3.2 illustrates the calculation of our risk premium estimate.

Table 3.2 – Calculation of Risk Premium Estimate

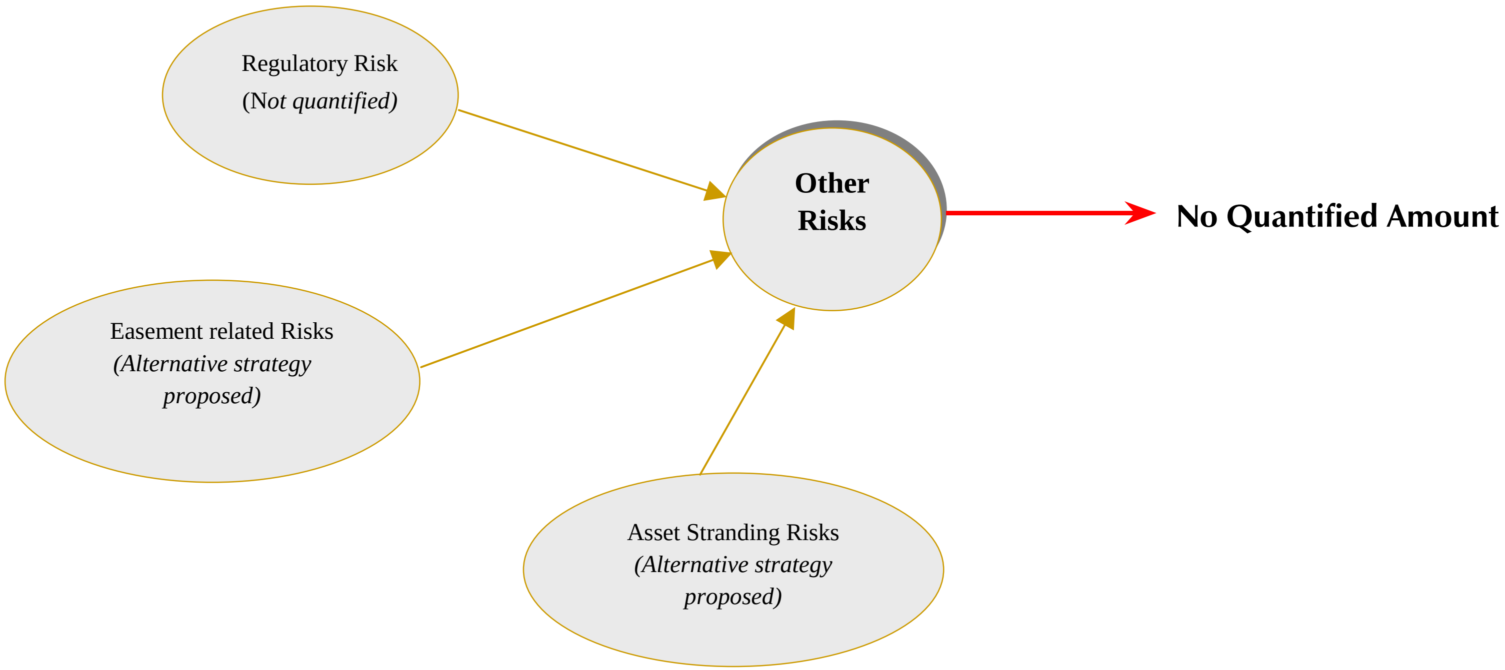
Probability of Default (Based on BBB credit rating)	**Average Amount at Risk**	**Potential Maximum Amount at Risk**	**Average Risk Premium Estimate**	**Maximum Risk Premium Estimate**
0.002	$10 million	$49 million	$20,000	$104,000

We estimate the annual premium for counterparty credit risk is within the range $20,000 to $104,000 pa. We have adopted a risk premium based on the mid-point of the range of about $60,000 pa based on the assumption that default is more likely to occur when the amount at risk is higher.

Based on EA's current transmission and distribution asset mix (12% of the assets are considered transmission assets), this annual premium can be segmented into $53,000 for EA's distribution assets and $7,000 for EA's transmission assets. We believe it is reasonable to use the transmission/distribution asset mix to split the risk premium between distribution and transmission assets as the relative proportions of transmission and distribution assets provides a proxy for the split of revenues between EA's transmission and distribution assets.

4 Other Risks

Figure 4.1 – Annual Risk Premium Estimates for Other Risks



4.1 Regulatory Risk

The potential cash flow impact of changes to the regulatory regime have not been considered in setting the EA's cost of capital (WACC) or cash flow projections. This regulatory risk can be regarded as an Non-Insured Event although it is not clear that this risk is diversifiable under a CAPM framework. In previous determinations Australian regulators have recognized the risks associated with the 'newness' of the regulatory regime by adding a premium to the WACC. Although regulators have since ceased to allow this premium we consider that the continuing evolution of the regulatory regime governing EA and the associated risk of regulatory 'shocks' still imposes real cost on EA.

The issue of regulatory risk is addressed in some detail in the Productivity Commission's 2000-01 Annual Report. The Commission argues that 'where long-lived investments are involved, the costs of regulatory error can be substantial'[24]. These costs are difficult to quantify and we have not attempted to estimate the expected cost of regulatory risk in this report. However, taking into account the capital base of the affected companies and the potential for regulatory risk to increase financing costs we believe this issue is significant and merits further consideration by IPART.

4.2 Easements

We have calculated that the central estimate of the cost of easement disputes over the 5 year period of the regulatory reset is $9m. This figure supports the $10m CAPEX for the risk mitigation program to acquire easement gaps proposed by EnergyAustralia. This is because the $9m represents our central estimate of the cost of easement disputes whereas it is likely that the range in the cost of easement disputes is very large. Therefore, in our view, an allowance of $10m for risk mitigation appears to be reasonably prudent.

We believe that it is appropriate for EnergyAustralia to have a prudent capital expenditure program for this risk rather than attempt to forecast and pay for the cost of easement disputes.

Details of our estimation of the costs of potential easement disputes are included in a separate report titled "Valuation of Non-Insured Events, Confidential Documentation".

[24] Productivity Commission Annual Report 2000-01, Chapter 1, p. 13

4.3 Asset Stranding Risk

Asset stranding risk represents the risk that EA's return of capital (in the form of depreciation) or revenue is less than expected because a higher than expected amount of assets are fully or partially stranded. For example, if a customer with dedicated distribution/transmission assets were to go out of business, then EA would lose future revenues associated with that customer and also potentially lose the depreciated value of that customer's dedicated distribution/transmission assets if those assets are "optimised" out of the regulated asset base.

Based on our discussions with EA, we understand that the total depreciated value of assets at risk of full or partial stranding due to business failure is about $8.6m. The largest of these assets at risk has a depreciated value of $2.4m. The bulk of these assets are associated with mining businesses.

As the depreciated value of the assets at risk of stranding is small relative to the total value of EA's regulated asset base, we do not believe it is cost-effective to conduct a detailed investigation into the likelihood of EA experiencing asset stranding at a rate higher than expected. However, we still believe that asset stranding risk poses a real risk to EA.

In our view, a reasonable method to recognise asset stranding risks would be to take an approach similar to those proposed in the following regulatory decisions:

- Review of Gas Access Arrangements, Final Decision, October 2002; and
- Queensland Transmission Network Revenue Cap: Decision, November 2001.

In the "Review of Gas Access Arrangements, Final Decision" for Victorian gas distributors, the ESC's proposed that *"with respect to redundant capital, the Commission would choose not to preserve the flexibility to write-down the regulatory value of distributor's assets at a future regulatory review"*[25]. Our understanding of this statement is that the regulator has undertaken not to remove any stranded assets or redundant capital from a distributor's asset base. Such an undertaking effectively removes the risk of loss of return

[25] Section 3.7.2 of Review of Gas Access Arrangements, Final Decision

on capital (WACC) and return of capital (depreciation) due to asset stranding for a distributor that has a regulated revenue cap. Our understanding of ESC's reasoning for this approach is that if gas distributors were to bear the risk of asset stranding, then the ESC would also *"be obliged to provide distributors with compensation for the expected cost of accepting this liability. If the expected loss is quantified precisely, then prices will be expected to be unchanged on average compared to the Commission's proposed approach."* [26].

In EA's case (where a price cap will apply) such an undertaking by IPART not to strand assets would remove the risk of not recovering capital expenditure but does not remove the risk of loss of revenue during the regulatory period when the asset is stranded. In our view, this appears to be consistent with the notion that regulated businesses would bear volume risk under a regulated price cap.

In the case of the "Queensland Transmission Network Revenue Cap Decision", the ACCC states that *"for accelerated depreciation to work efficiently it is critical for the TNSP to advise the regulator well in advance of by-pass risk actually occurring"*[27]. The ACCC then goes on to state *"The Commission acknowledges that there is sufficient uncertainty in the Queensland market, making it difficult for Powerlink to identify with a high degree of precision which assets will face stranding over the Regulatory period"* [28]. Finally, the ACCC states that *"Where the Commission identifies that an asset (already identified by Powerlink) has been stranded, it will provide an additional depreciation allowance to compensate for lost revenues."* [29]. Our understanding of these statements is that the ACCC recognises that asset stranding is a risk that should be compensated for and that the ACCC believes that it is appropriate for compensation to occur after the asset is stranded due to the difficulty of predicting when an asset may become stranded.

In conclusion, we believe that the approaches adopted by the ACCC and the ESC for stranded asset risk represent the more appropriate approaches to dealing with asset stranding than forward-looking estimates of expected asset stranding costs.

[26] Section 3.7.2 of Review of Gas Access Arrangements, Final Decision

[27] Section 2.11.2 of the Queensland Transmission Network Revenue Cap: Decision

[28] Section 2.11.2 of the Queensland Transmission Network Revenue Cap: Decision

[29] Section 2.11.2 of the Queensland Transmission Network Revenue Cap: Decision

5 Reliances and Limitations

- In completing this review we have relied on documents and information provided to us by EnergyAustralia for the purpose of our review. These source documents are referred to in the Introduction and Scope section of this report. It should be noted that if any of this information is inaccurate or incomplete, this report may have to be revised.
- The report should be considered as a whole. Members of Trowbridge Deloitte staff are available to answer any queries, and the reader should seek that advice before drawing conclusions on any issue in doubt.
- It is not possible to put a value on non-insured risks with certainty. As well as difficulties caused by limitations on the historical information, outcomes remain dependent on future events. Although we have prepared estimates in conformity with what we view to be the likely future experience, actual experience could vary considerably from our estimates. Deviations are normal and are to be expected.
- This report has been prepared for the sole use of EnergyAustralia for the purpose stated in Part 1 ("Introduction and Scope'). No other use of, or reference to, this report should be made without prior written consent from Trowbridge Deloitte, nor should the whole or part of this report be disclosed to any other person.

Part III Appendices

A Hardening of Insurance Market

A.1 Introduction

The insurance market and commercial insurance in particular goes through cycles where the market is soft (“cheaper”) or hard (“expensive”). At different times of the cycle the cost of insurance can vary considerably. Further, the terms under which insurance is offered may also change. This includes changes to levels of deductibles/excesses, changes to exclusions and changes to policy wordings. A company’s own claims history will also impact on the premiums sought by insurers and a bad claims history may prompt a substantial rise in premium.

The insurance market goes through cycles as a result of:

- The available capacity in the market (supply/demand);
- The availability and terms of reinsurance programs;
- The recent worldwide claims history (including catastrophe experience);
- The current investment markets (in particular the bond market); and
- The current profitability of market segments.

Market Capacity

As capacity is added or withdrawn from the market, there is an adjustment to the supply available for insurance segments. Generally, capacity will be withdrawn due to insurers seeing a certain segment as unprofitable or from insurers failing (eg: HIH) or placing their portfolio into run-off. This reduction in supply provides other participants with opportunities to increase premiums. When premiums increase to a level where substantial underwriting profits are being generated then this will encourage new players to enter/re-enter the market segment. The increased competition tends to cause a reduction in the price of insurance.

Effect of Reinsurance

The premium a direct insurer is required to pay to cover its re-insurance program will also directly impact the premiums charged to the end user. The reinsurance market will be affected by similar factors as the direct insurance market (for example, capacity availability, recent claims history and investment markets).

Claims History

When claim frequencies or average sizes deteriorate then the insurance market needs to reassess the risk estimate allowance in its premiums. This is particularly important in products that have low likelihood of occurrence but large and volatile claims costs (eg: catastrophe insurance). When pricing risk an allowance is made for these low frequency high cost events but a worse than expected claims history would lead to a re-evaluation, and hence re-pricing of the risk. Similarly where claims history is better than expected, a reduction in premiums can be expected.

Investment Markets

When pricing, insurers make an allowance for investment returns. At times of strong investment performance, insurers may accept underwriting losses for investment profits. As investment returns tighten, insurers may reassess their underwriting positions and re-price to generate underwriting profits.

Profitability of Market Segments

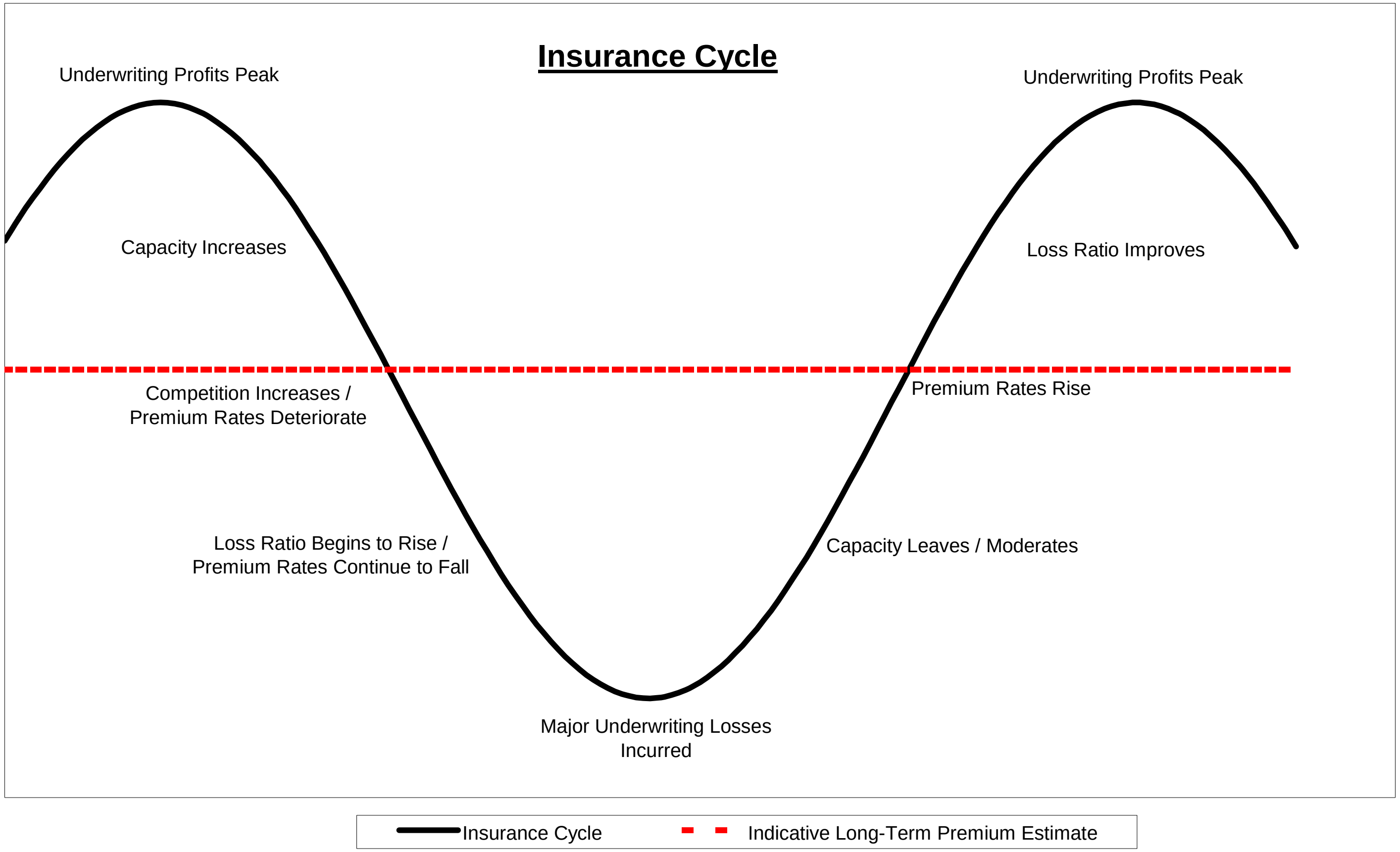
As outlined above, there are a number of reasons why certain market segments become unprofitable. In these instances, insurers will look to re-price to restore profitability. At times prices may be kept artificially low for competitive purposes. However, this cannot be a long-term strategy and over time the market will look to increase premiums on unprofitable segments (or capacity is withdrawn).

Impact of Timing

When the insurance industry acts to improve its financial performance by raising prices and tightening conditions, insurers’ gains can be eroded initially by the impact of past claims and the need to build adequate reserves for future claims. Therefore it takes time for the higher prices to translate into underwriting profits. This leads to a long upward climb to the insurance cycle.

Figure A.1 summarises the cyclical nature of the insurance market. The straight line shows an indicative long-term average premium estimate. At different times of the insurance cycle, insurance can be seen as being good value (worth taking out) or as bad value (worth self-insuring).

Figure A.1



A further impact on the insurance premiums is where claim size and/or claim frequencies worsen over time. This is particularly the case in liability and professional indemnity insurance where court cases, new technology advances and generally more public awareness of its rights, can lead to steps in the total claim cost due to a higher number of claimants or higher payments per claim. Referred to as superimposed inflation typical allowances for this effect range between 3% and 6% p.a.

A.2 Current Market Expectations

Prior to the terrorist attacks of September 11 the insurance market was already hardening across all commercial segments, from a low in early 2000. The key lines of insurance affecting EnergyAustralia's business are industrial special risks (ISR), public liability commercial motor vehicle. The expected increases were different for each insurance market segment and rates varied considerably by insurer.

Table A.1 summarises the average increase in rates expected for 2002 to 2004 based on the 2002 General Insurance Industry Survey by JPMorgan and Deloitte Touche Tohmatsu.

Table A.1 Estimated Real Premium Increases

	Estimated Average Premium Increases		
Market Segment	2002	2003	2004
Fire & ISR	45%	19%	8%
Public and Products Liability	51%	23%	13%
Commercial Motor Vehicle	11%	7%	6%
Workers' Compensation	5%	2%	5%

A.3 Impact of September 11 on the Insurance Cycle

It will be some time before the full effects of September 11 on the insurance industry can be assessed. The immediate response from underwriters and reinsurers has been to increase premiums and reduce the level of insurance cover provided by increasing policy deductibles and excluding certain risks (e.g. terrorism). The level of premium increase has varied significantly between insured risks and rate increases well in excess of 100% have not been unusual.

This dramatic shift in insurance pricing represents a step change in the normal insurance cycle. The reasons for this pricing shock can be attributed to the following key factors:

- Loss of insurance capacity following the reduction in insurers' capital;
- Increased reinsurance costs following the loss of capacity in the reinsurance market – this will have a flow-on effect on direct insurance rates; and
- Reappraisal of risk by insurers to allow for larger losses from catastrophe events and accumulations of risk than had previously been allowed for.

A.4 Outlook for insurance premiums after September 11

The future path of insurance premium rates after September 11 is uncertain. The factors affecting the likelihood of further premium increase or premiums stabilising at current levels compared to the likelihood of premiums falling from current levels are discussed in the following paragraphs:

Rising / Stabilising Premiums

Factors impacting the likelihood of further premium increases, or premiums stabilising at their new higher levels, include:

- There has been a reappraisal of risk by insurers and reinsurers following the September 11 events. This represents a fundamental change in the assessment of the risks faced by insurers and therefore is unlikely to be given away even in a 'soft' market;
- It takes some time for high prices to flow through to an increase in insurers' and reinsurers' capital. This delay in rebuilding capital will continue to limit insurance and reinsurance capacity; and
- Consolidation and a closer focus on capital management should enable the insurance industry to maintain increased rates.

Falling Premiums

The prospect of insurance premiums falling from current levels is possible if:

- The premium increases announced in the months immediately after the events of September 11 overshoot the ‘reasonable’ level of increase required to meet the increased risks of writing insurance business; and
- Large premium increases attract new capital into the insurance market forcing premium levels down and leading to a resumption of a typical insurance cycle.

The outcome for insurance premium rates over the regulatory reset period (2004/05-2008/09) is very difficult to assess at this point. The September 11 events will have a major long-term impact on the insurance market but it will be some time before the impact can be accurately assessed. Therefore we have not made any allowance in this report for a change in EnergyAustralia’s insurance premiums over the regulatory reset period.

B Adjustment to Central Estimate

When establishing insurance premiums in a commercial environment an insurance company will make allowance for:

- the expected claims cost, including allowance for catastrophes;
- inflation and anticipated investment returns on the timing difference between the receipt of premium and the payment of claims;
- acquisition costs such as brokerage;
- the administration cost of running the insurance business, including the cost of handling claims; and
- a profit margin to provide a return to its shareholders commensurate with the risk of the business.

The first of these elements, the expected claims cost, is the same as the central estimate concept explained previously. The bulk of this report is dedicated to the assessment of the central estimate (risk premium) for the EnergyAustralia non-insured assets.

In addition to recovering the cost of the risk premium it is our opinion that EnergyAustralia should also be allowed to recover a number of other elements of the hypothetical commercial insurance premium, as discussed below.

Having taken on the responsibility for managing and paying the claims associated with self-insured liabilities it is appropriate to recover the associated administrative costs. The major component of these costs arises from staff salaries but they also include costs of training, seeking recoveries from third parties, monitoring experience and maintaining appropriate risk management systems.

We have assumed that all of these costs are adequately reflected in the Operation and Maintenance costs, but additional recoveries should be sought should this assumption be false or the O&M allowance inadequate.

Shareholders of insurers seek returns on their investments that adequately reflect the risk of the business. The greater the perceived riskiness, the greater the required return and the greater the profit margin sought.

While the commercial profit motive is not appropriate in this case, there is a case for seeking to “recoup” costs at a level that exceeds the risk premium. This is because the nature of the self-insured risks is such that the loss experience in any relatively short period is highly uncertain. As shown elsewhere in this report, key components of the EnergyAustralia self-insured risks involve low frequency, high severity events. In statistical terms, the claims cost distribution is highly skew. So while we have placed an expected value (central estimate) on non-insured claims, there is clearly a lower bound of zero cost (no claims at all), with an upper bound of many millions of dollars.

A business which chooses to self-insure insurable risks is exposed to greater earnings uncertainty than a company which insures those risks. If the WACC determined for EnergyAustralia’s regulated revenue reset does not make appropriate allowance for the extra earnings uncertainty associated with self-insured risks then a ‘contingency margin’ adjustment to the central estimates calculated would be appropriate. The impact on EnergyAustralia’s business of variations in earnings from the central estimate is unlikely to be symmetric. Typically the costs of dealing with worse than expected uninsured losses will outweigh the benefits of better than expected experience. This contingency margin would be used to cover the costs associated with extra earnings uncertainty. These costs include:

- Business disruption costs following the occurrence of low likelihood uninsured losses;
- Cost of raising short-term funding to meet unexpected shortfalls; and
- Negative reaction of potential investors to a perceived increase in risk following higher than expected uninsured losses.

We suggest that the IPART consider allowing regulated distribution businesses to build up a volatility and catastrophe reserve by accumulating the contingency margins assessed for each uninsured risk. The reserve would be used to meet the costs of worse than expected uninsured losses. While theoretically a volatility and catastrophe reserve would be determined statistically, it would not normally be possible to assess the appropriate reserve level with the limited claims experience of an individual business. Therefore the contingency margin approach is recommended as a practical alternative.

However, for the purpose of this report we have not included any adjustment to the central estimate in our calculation of the risk premium estimate.

C Catastrophic Environmental Risks Faced by EnergyAustralia

Introduction

EnergyAustralia's assets are subject to losses arising from catastrophic environmental events. We have identified bushfires, earthquakes, windstorms and hailstorms as potential catastrophic environmental events. This section of the report examines the approach adopted to estimate the probability of catastrophic environmental events.

A Comment on Catastrophic Event Return Periods

Catastrophic events are events that typically have a return period of 1/100 to 1/1000, however as catastrophic events have such low probabilities it is often difficult to derive probability estimates and meaningful expected losses. Blong (1995) identifies PML (Probable Maximum Loss) events as 1/100 to 1/1000 year events. An indication of typical return periods for catastrophic events insured by Australia's leading insurers by premium income may be inferred from a survey conducted by Andrews et al (1995). In a survey of Australia's leading insurers, insurers *were asked to nominate the return period beyond which events are ignored for PML purposes.* The results are presented in Table C.1.

Table C.1 - Maximum Return Periods for Insurers

Return Period	Number of Insurers
200 years	2
500 years	4
1000 years	2
Unknown	1

C.1 Catastrophic Bushfire Loss

NSW Bushfire Experience

Catastrophic bushfires provide a significant exposure to EnergyAustralia, either to own property damage or through third party liability for incidents caused by EnergyAustralia's assets.

Based on statistics that we obtained from the Fire Investigation Unit of the NSW Rural Fire Service, the causes of bushfires (for the fires investigated) in NSW for the recent fire season (2002/2003 fire season) are shown in Table C.2 below.

Table C.2
Causes of Bushfires in Most Recent Fire Season

Cause	Number of Fires	Percentage of Fires
Deliberate Ignitions	224	61.3%
Burning Activity	25	6.8%
Campfire/BBQ	8	2.1%
Electrical/Power Lines	19	5.2%
Lightning	62	16.9%
Machinery/Equipment	10	2.7%
Spot Fires/Re-ignitions	9	2.5%
Undetermined	8	2.1%
Total	**365**	**100%**

Statistics from the Electricity Association of NSW show the number of bushfire incidents in NSW split by cause for the period 1990 to 2000. Table C.3 below shows these statistics:

Table C.3
Causes of Bushfires by Electricity Assets

Cause	Further Description of Cause	Number of Bushfires
Conductors clashing/trees/wind/top onto bottom layer	Conductor Clashing	22
	Tree	50
	Wind/Storm	19
	Miscellaneous	5
Neutral/Conductor failure/Loose line clamp		32
Pole/Cross-arm failure		28
Bird/Animal		29
Pollution of Line	Pole-top Fire	4
	Cross-arm Fire	5
	Dirty Insulators	11
	Pollution on Line	6
Third part person/Vehicle hit distributor property (e.g. poles, substations or lines)		25
Insulator tie failure		24
Fuse failure		25
Lightning		11
Incorrect connection/disconnection		6
Power lines down or low hanging/conductors striking ground		5
Employee/equipment damaged 3rd party property whilst doing repairs		3
Transformer fault		3
Circuit breaker failure		1
Total		**314**

C.2 Catastrophic Earthquake Risk

Australian Earthquake Risk

EnergyAustralia's assets are subject to the risk of major loss as a result of a catastrophic earthquake. Compared to countries located close to active tectonic zones Australia has a small earthquake hazard. However, earthquake hazard in Australia is real as demonstrated by the Newcastle earthquake. The Queensland University Advanced Centre for Earthquake Studies makes the following assessment,

> *"Australia is seismically active and earthquakes pose a substantial risk as demonstrated by the deadly magnitude 5.6 Newcastle earthquake of 1989. When compared to plate margin regions such as California or Japan, the rate of activity is lower, but relative to other intraplate regions, Australia's earthquake activity is moderate to high."*

Earthquake hazards are typically expressed as the probable ground motion that may be recorded at a given locality with a particular frequency. Figures C.1 and C.2 show the distribution of Australia's earthquake risk and hazard respectively.

Figure C.1- Earthquake Risk Map

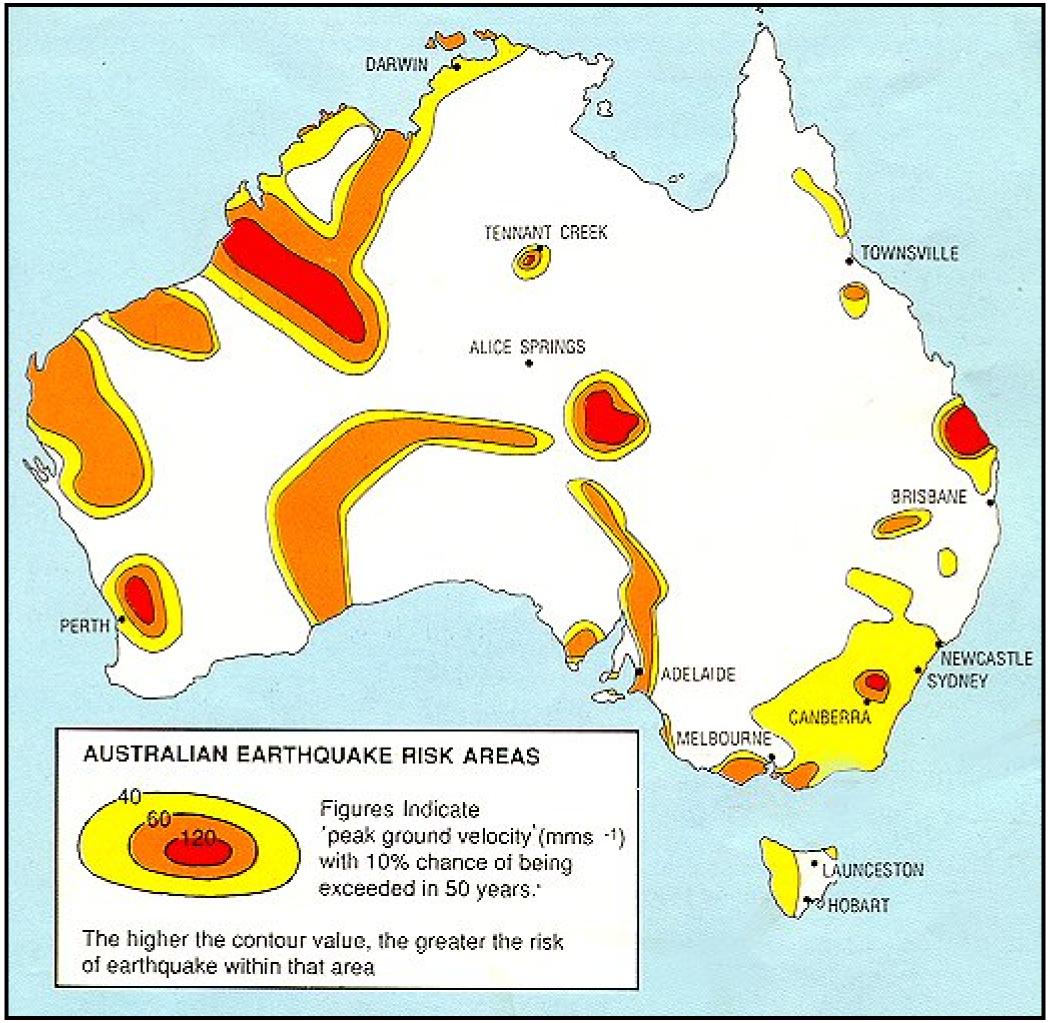
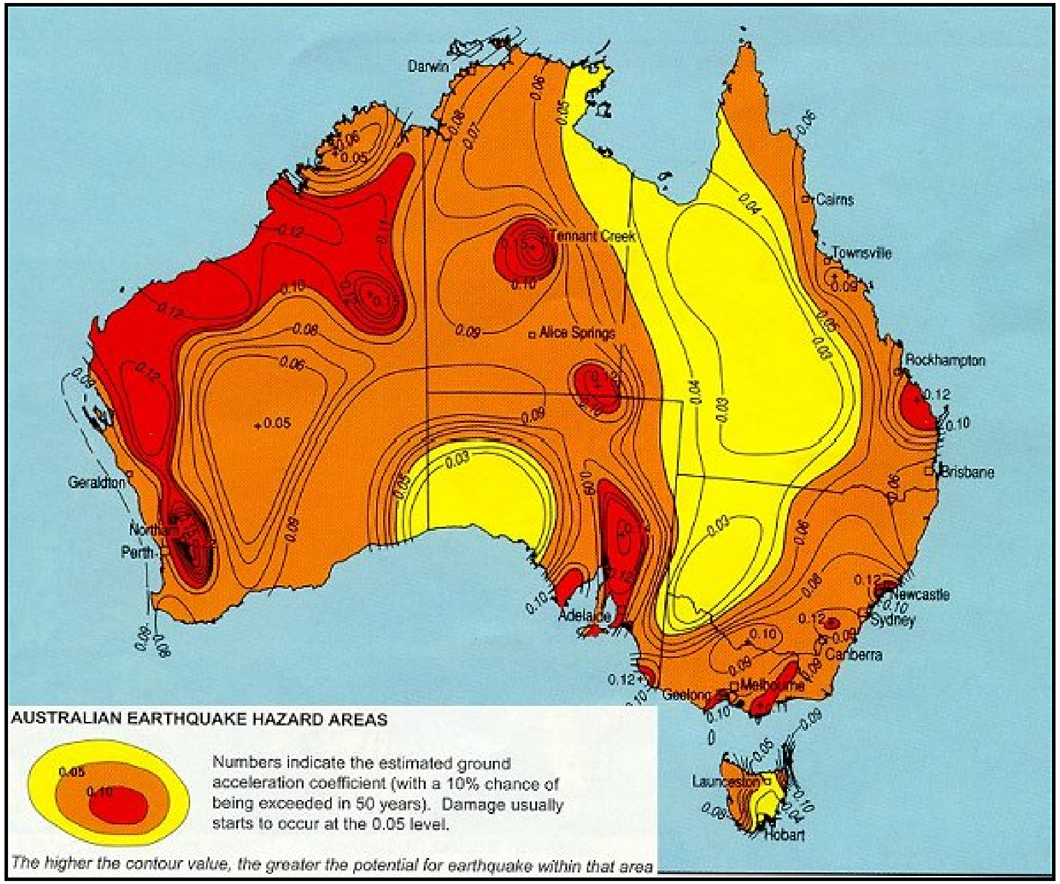


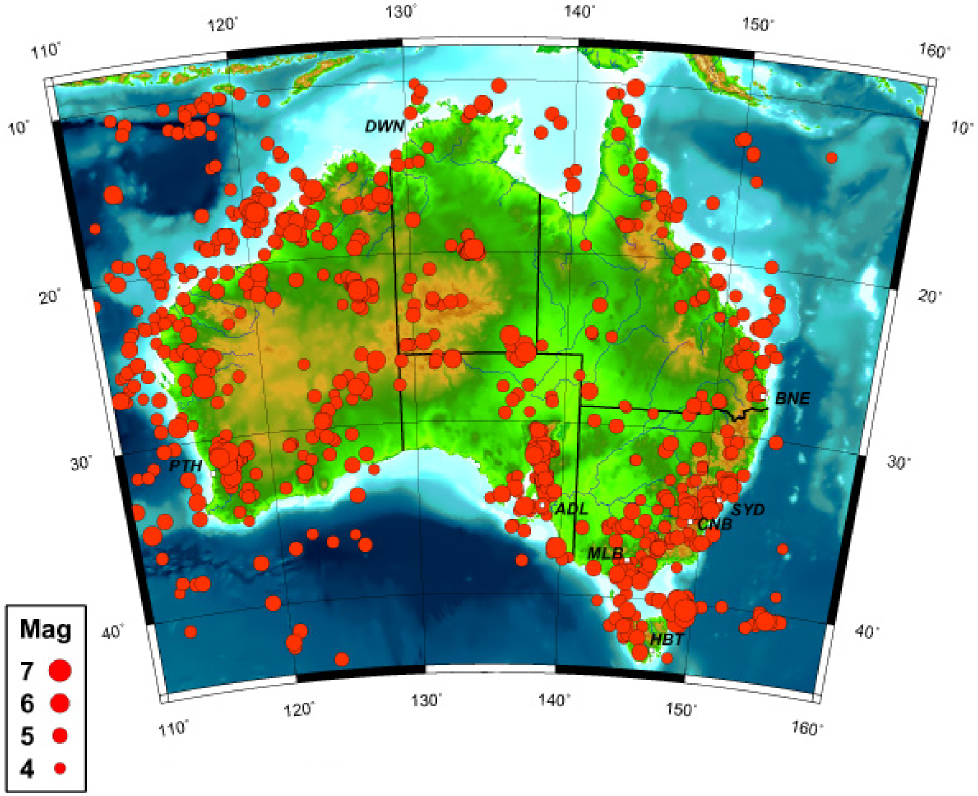
Figure C.2 - Earthquake Hazard Map



NSW Earthquake Risk

From Figures C.1 and C.2 it is evident that other parts of NSW are subject to earthquake risks comparable to Newcastle. Further evidence illustrating the risk of earthquake in NSW is shown in Figure C.3. Figure C.3 shows earthquakes that have occurred with Richter magnitudes greater than 3.5 and suggests the higher seismicity and hazard regions are along eastern Australia.

Figure C.3 - Australia Earthquake map



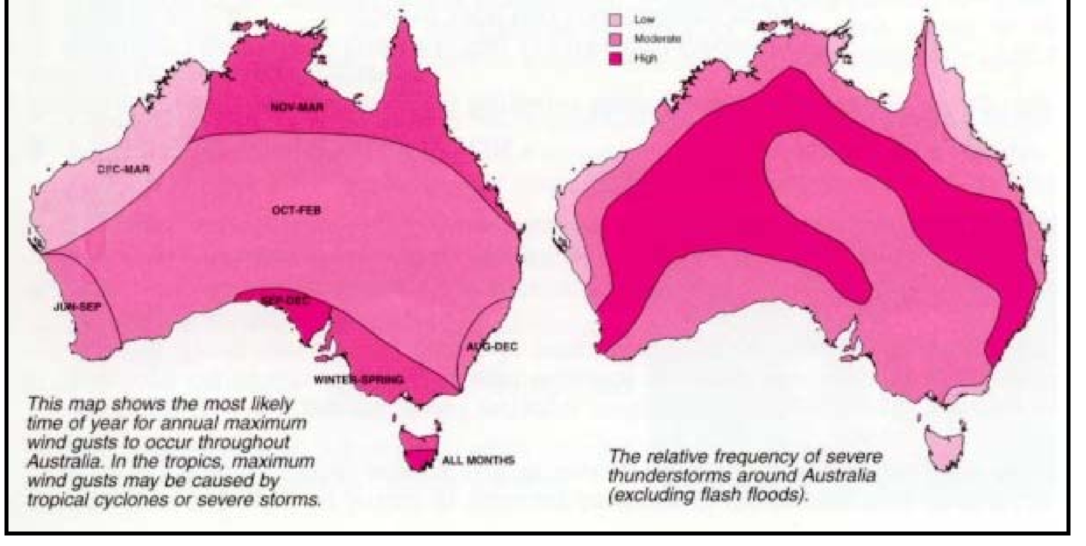
Assessment of Catastrophic Earthquake risk

Quantification of earthquake risk is at best an imprecise science. Blong[30] with reference to earthquake return periods states, "*In many cases it is impossible to make rational estimates of return periods*". The difficulty of making return period estimates is further compounded by limited data, Australia earthquake data is based on 150 years of historic record and instrumental data of a few decades.

C.3 Catastrophic Windstorms

Catastrophic windstorms have the potential to cause major damage to EnergyAustralia's. Figure C.4 shows the frequency of severe weather events in Australia. Figure C.4 shows that the area of NSW covered by EnergyAustralia's network can be considered as having a medium to high incidence of severe thunderstorms.

Figure C.4



[30] "PML Events - one coming to a place near you, real soon now! 1995"

D Fitting the Pareto Distribution for Bushfire Liability Claims

The Pareto distribution is applicable where a power law is expected to apply. The Pareto distribution can be specified as follows:

$$f(x) = \alpha c^{\alpha} x^{-\alpha-1}$$
$$x > c$$
$$\alpha > 0$$

We used a maximum likelihood estimation technique to fit the bushfire liability data. For a Pareto distribution, the maximum likelihood estimates are as follows:

Where $\mathrm{X}_1, \mathrm{X}_2, ..., \mathrm{X}_n$ represent individual observations of bushfire liability costs :

$$\alpha = \frac{n-1}{\sum_{i=1}^{n} \ln \frac{X_i}{c}}$$
$$c = Min(\mathrm{X}_i)$$

Based on the bushfire liability claims data we received, the maximum likelihood estimates of α and c are 0.20304 and 400 respectively.

Observations for the Fitted Distribution

The key observations for the fitted distribution are as follows:

- The fitted distribution implies a fire that causes twice as much liability is about 2.30 times as rare. This compares reasonably well with the conclusion in the study by B. Malamaud, G. Morein and D. Turcotte where a fire that burns twice the area occurs 2.48 times as rarely;
- With a $10m deductible per bushfire liability event, the average bushfire liability based on the fitted distribution is $1.6m; and
- There is limited data with which to fit a distribution, therefore, results derived from the fitted distribution are subject to a fair amount of uncertainty.

Goodness of Fit

The following table compares the claim size distribution implied by the fitted distribution to that observed in historical claims data:

Table D.1

Lower Bound of Claim Size	Upper Bound of Claim Size	Historically Observed Number of Claims	Historically Observed Percentage of Claims	Predicted Number of Claims based on Fitted Distribution	Predicted Percentage of Claims Based on Fitted Distribution
400	10,000	7	25.9%	13	48.0%
10,000	50,000	5	18.5%	4	14.5%
50,000	150,000	6	22.2%	2	7.5%
150,000	500,000	5	18.5%	2	6.5%
500,000	Infinity	4	14.8%	6	23.5%
	Total	27	100.0%	27	100.0%

When compared to the actual claims experience, the fitted Pareto distribution appears to:

- Overestimate the number of small and large bushfire liability incidents that occurs (that is, the number of claims under $10,000 and claims over $500,000 appear to be overestimated)

- Underestimate the number of claims for bushfire liability incidents costing between ($10,000 and $500,000).

However, the fitted distribution is consistent with the results of the bushfire study conducted by B. Malamaud et al.

In our view, given the small amount of data, it is not appropriate to conduct more complicated statistical tests regarding the goodness of fit.

E Details for Public Liability Risk Premium Estimate

Due to the commercially sensitive nature of these claims details of our calculation for the annual risk premium for public liability are included in a separate report titled "Valuation of Non-Insured Events, Confidential Documentation".

F List of Documents

Analysis of Fire Causes on or Threatening Public Land in Victoria, 1976/77 to 1995/96
Research Report No.49, Chris Davies, Fire Management Branch October 1997

Electrical Supply Industry Group Insurance Scheme, David A. Zaman, 30 June 2002

Ubiquity, Mark Buchanan, 2000

B. Malamaud, G. Morein and D. Turcotte, Forest Fires: an example of self-organised critical behaviour. Science 1998; 281: 1840-2

http://www.ucfpl.ucop.edu/I-Zone/XVIII/ignintro.htm, Introduction to Ignition Field Guides, College of Natural Resources, University of California, Berkeley

How Far do Bushfires Penetrate Urban Areas? Australian Bushfire Conference, Albury, July 1999.

Estimation in the Pareto Distribution, Mette RytGaard