ETSA Utilities
Delivering energy to South Australians

ETSA Utilities ABN 13 332 330 749,
a partnership of:
CKI Utilities Holdings Pty Ltd
ABN 54 091 142 380
HEI Utilities Holdings Pty Ltd
ABN 50 091 142 362
CKI/HEI Utilities Distribution Pty Ltd
ABN 19 091 143 038
each incorporated in Australia
CKI Utilities Development Limited
ABN 65 090 718 880
HEI Utilities Development Limited
ABN 82 090 718 951
each incorporated in The Bahamas

1 February 2008

Mr Chris Pattas
General Manager
Network Regulation South Branch
Australian Energy Regulator
GPO Box 520
MELBOURNE VIC 3001

Dear Mr Pattas

Issues Paper – Guidelines, Models and Schemes for Electricity Distribution Network Service Providers

This letter is in response to the above AER Issues Paper which considers the development of guidelines, schemes and models to support the transition to a nationally consistent framework for the economic regulation of electricity distribution networks.

We understand that the release of this Issues Paper is part of a preliminary consultation process and that further consultation will occur on the proposed guidelines, models and schemes discussed, as well as other guidelines and schemes relevant to Chapter 6 of the NER, that the AER is considering.

It is in the context of this preliminary consultation process that we have identified key matters that we consider the AER should give appropriate consideration to as they further develop the guidelines, models and schemes. These key matters are discussed below under your section headings.

1.6 Other guidelines, schemes and information requirements

A. Development of a Demand Management Incentive Scheme

The AER commented in the Issues Paper that:

> *"The AER intends to release an issues paper in 2008 on the development of a demand management incentive scheme.*

Depending on the issues raised by interested parties, the time frame required for development, and whether the AER develops a demand management incentive scheme, it may not be possible for such a scheme to be published in time for consideration during the framework and approach processes for the Queensland and South Australia resets."

ETSA Utilities queries whether it is necessary, in this initial transition to national arrangements, for the AER to have concluded a demand management guideline before the AER could consider such a matter within the Framework and Approach Paper. It may be that South Australian experience can assist in establishing a workable arrangement that will promote demand management with a view to lowering the total costs of electricity to customers in the coming years. We will further discuss this issue with the AER in the coming months.

ETSA Utilities will discuss the opportunities for a Demand Management Scheme in our 2010 Reset with the AER in the Framework and Approach paper irrespective of the completion or not of a Guideline by the AER on this topic. It may be that a workable transitional arrangement can be put in place whilst longer-term national arrangements are being developed.

B. Transition from Pre-tax to Post-tax Regulation

The Issues Paper notes the transition from pre-tax to post-tax regulation is an issue on which some DNSPs will require the AER's guidance but that it may be more appropriate to provide this guidance through the framework and approach processes rather than through a national guideline. This is due to this issue affecting DNSPs in different ways, including the introduction of an entirely new post-tax framework for some, and a change in the approach for others.

We note the position of the AER. As promoted in the Derogations incorporated in the Rules, Clause 9.29.5(b)(1) and as previously advised in our response to the AER Preliminary Positions Paper on Matters Relevant to Distribution Determination for ACT and NSW DNSP's for 2009-2014, ETSA Utilities will shortly seek to engage with the AER as to the appropriate transitional arrangements to take into account the change from a pre-tax to a post-tax revenue model.

ETSA Utilities will shortly seek to engage with the AER as to the appropriate transitional arrangements to take into account the change from a pre-tax to a post-tax revenue model.

2.1 Post-tax Revenue Model

A. Suitability for Distribution Regulation of PTRM Developed for Transmission

The AER has sought comment on whether the PTRM developed for electricity transmission provides a suitable basis for the determination of revenues in distribution regulation.

ETSA Utilities considers the transmission PTRM is suitable for distribution regulation provided there is appropriate recognition of distribution specific factors, such as customer contributions which is not part of the current transmission based revenue forecasting model. Our response to the Issues Paper considers some of the specific factors that have been raised by the AER.

In principal, the transmission PTRM is suitable for distribution regulation provided appropriate recognition is given to distribution specific factors, such as customer contributions.

B. Tax Depreciation

The Issues Paper notes, in the context of the PTRM for transmission, that:

> *"For the purposes of calculating tax liabilities, tax depreciation is also calculated using a straight-line method. Businesses are free to propose other methods to the AER, which may require amendment to the PTRM for use in a reset process."*

The Income Tax Assessment Act 1997 allows two methods for calculating the decline in value of a depreciating asset, that is, the prime cost method (straight line) and the diminishing value (reducing balance) method.

The taxpayer must choose the method that is to apply before lodging the income tax return for the income year to which the choice relates. In addition, the choice is exercised on an asset-by-asset basis and on a year-by-year basis. The choice of method, once made, applies not only for that income year but for all later years in which the taxpayer claims tax depreciation for the decline in value of that asset.

There are legitimate reasons for an efficient business to exercise the choice, provided for in Income Tax Assessment Act 1997, to use either prime cost or diminishing value for the tax depreciation of a depreciable asset.

The PTRM should be so designed to enable DNSPs to exercise the discretion provided for in tax legislation.

For the purpose of calculating tax liabilities within a post-tax regulatory revenue model, DNSPs should be entitled to calculate tax depreciation consistent with income tax legislation.

C. Capex Recognition

The transmission PTRM adopts a hybrid approach whereby assets are depreciated from when they are commissioned, while returns on capital are calculated from when capital expenditure is incurred. The AER considers this as being compliant with the amended chapter 6, as depreciating assets on an as-commissioned basis ensures that businesses recover the cost of assets from when they first contribute to service delivery and yet the business earns a return on the investment from the time the investment is incurred, subject to the discussion that follows.

ETSA Utilities understands that the transmission PTRM defers the cash flows associated with the return on and of new assets. In other words, under the hybrid approach the return on a new asset is received in the year after the capital expenditure is incurred, and depreciation on new assets begins in the year following an asset's commissioning. To compensate for the delay in providing a return on new assets the PTRM grosses up the incurred expenditure for a half a year of the WACC.

The AER's modelling approach does not impact on the net present value of the returns from the asset, but in ETSA Utilities opinion this approach has an unnecessary negative impact on a firm's cash flows.

The impact of the timing of cash flows is significant, particularly in circumstances where the jurisdictional regulator previously allowed the return on and of capital in the year of addition as allowed revenue. A consequence of the AER's approach is it will lead to increases in required borrowings and will negatively impact on credit rating ratios. This matter becomes more critical during times of significant infrastructure spending such as that experienced in Australia today.

The transmission guidelines do not seem to provide any economic rationale for such an approach, other than to simplify the modelling algorithms. ETSA Utilities submits that the AER's deferment of cash flows is inconsistent with the NER and requires only minor changes to the PTRM.

In addition, in our view, by deferring the start of depreciation the PTRM is inconsistent with the requirements of clause 6.5.5(b)(1) of the NER. Clause 6.5.5(b)(1) requires that an asset be depreciated over its economic life. A consequence of deferring depreciation on new assets to the year following its commissioning is to deny distribution networks the opportunity to depreciate new assets from the start of their economic life. A more reasonable approach would be for the PTRM to assume that on average a new asset begins its economic life in the middle of a regulatory year.

To give effect to a mid year start for depreciation the PTRM could be easily changed by allowing half the annual depreciation allowance on new assets in the year that they are commissioned. In addition, to give effect to the mid year return on capital the AER would only need to transfer the capitalised return on new assets into annual revenue in the year that the expenditure occurs. Adopting this approach would bring the AER in line with other regulators such as IPART and ESCOSA.

These cash flow issues, if unresolved, reduce current network tariffs below the cost of service, and in doing so, place an inappropriate burden on future customers.

In principal, ETSA Utilities considers the AER hybrid approach as appropriate provided the return on and of capital in the year of addition is included in allowed revenue for that year. The cash flow issues discussed above should not be ignored by the AER, particularly where the jurisdictional regulator previously allowed the return on capital in the year of addition as allowed revenue.

D. Inflation Bias

The Issues Paper notes the issues with the use of Commonwealth Government securities in estimating forecast inflation. There is now general acceptance that there is currently some distortion in the indexed CGS market and that observed yields may no longer provide an appropriate benchmark proxy for the risk free rate. The Reserve Bank of Australia stated:[1]

> *"the Reserve Bank does not believe there are distortions in the CGS* [Commonwealth Government Securities] *market and hence the CGS bond yield remains the best proxy for a risk-free rate. This is not true, however, of the indexed bond market and hence this market may no longer be providing a suitable benchmark."*

1 RBA, Letter to Joe Dimasi dated 9 August 2007, page 1.

The methodology for forecasting inflation is critical if the proposed distribution PTRM, follows the transmission PTRM, and calculates inflation within the model (from the inputs of the real and nominal risk free rates). ETSA Utilities submits that forecast inflation should become an input into the distribution PTRM. This allows forecast inflation to be either determined by an alternative objective market-based methodology (if available) or alternatively an appropriate assessment of forecast inflation by the RBA.

Whatever the methodology chosen, it is critical that the determination of forecast inflation reflect the longer term outlook for inflation consistent with the framework of the capital asset pricing model. A short or medium 2-3 year outlook is inappropriate and inconsistent with the timeframe for determining other cost of capital parameters.

ETSA Utilities believes that forecast inflation should be an input into the PTRM. In our opinion, forecast inflation should be estimated using either an objective market-based methodology (if available) or alternatively an appropriate assessment of forecast inflation by the RBA.

E. Cash-flow Timing

The AER considers that in moving towards a national regulatory framework, there is merit in adopting a single set of timing assumptions for all DNSPs. We agree.

The AER further noted that:

> *"The timing assumptions in the transmission PTRM have been the subject of several rounds of consultation. While the AER considers these assumptions to be generally appropriate, some cash-flow timing issues may need to be re-examined in the context of distribution regulation".*

In our view, there are no material differences between transmission and distribution with respect to cash flow timing issues, that necessitates a modification of the PTRM specifically for distribution regulation.

The PTRM for transmission assumes that all cash-flows except for capital expenditure occur at the end of each regulatory year. Capital expenditure is recognised in the middle of each year and in doing so recognises that that capital expenditure can occur evenly throughout the year, which is approximated by the middle of the year assumption.

The AER have sought comment in whether there is merit in considering modifications to the PTRM to remove any potential biases that may exist in the transmission PTRM arising from the cash flow assumptions.

Invariably revenue modelling for regulated businesses requires reasonable forecasts and assumptions to be made about the operations being modelled. In our view, attempts to recognise and adjust for a perceived inaccuracy of any one particular cash flow assumption are unwarranted. We consider this to be the case for two reasons.

Firstly, adjusting for small systematic biases makes modelling significantly more complex and can lead to an increased risk of modelling errors, that are related to modelling complexity rather than to conceptual soundness. Modelling intra year cash flow requires the PTRM to have assumptions of the timing of:

- all the PTRM building blocks, ie:
  - return on capital;
  - economic depreciation;
  - operating costs;
  - company tax payments;
  - dividend imputation credits; and
  - any revenue adjustments, due to incentive schemes;
- distribution revenues, such as DUoS and excluded services; and
- any non-PTRM cash flows, for example:
  - transmission costs, such as TUoS and connection charges;
  - embedded generation costs;
  - cross boundary network charges;
  - energy efficiency payments (ie, d-factor payments); and
  - any other pass through costs.

For the PTRM to correct for each of these intra year cash flows would create an overly complex regulatory model with an associated increased risk of errors. An associated cost of increased complexity, is the regulatory burden on the distribution networks and the AER, to assess and review each of these timing assumptions.

Secondly, normal commercial practice in the marketplace for transactions of this type is to use the assumption of cash flows occurring at the end of a period. To pursue greater precision than sought by real investors in real markets suggests that the AER could be seeking to apply inappropriate benchmarks drawn from theoretical models.

ETSA Utilities does not see the basis for changing from a model that is well proven and internally reconcilable to a model that attempts to adjust for small systematic biases at the risk of making modelling significantly more complex and prone to unidentified errors.

In our view, attempts to more "accurately" model cash flows would unnecessarily increase the administrative burden and complexity of the modelling and may suggest a level of precision which is beyond that employed within the five year forecasts.

This "over engineering" cannot be justified particularly in the transition to the national framework for distribution regulation. Rather, the AER focus should be on addressing the significant transitioning issues that it must consider in the move to a national framework.

ETSA Utilities considers that:

- there is merit in adopting a single set of timing assumptions for all DNSPs;
- there are no material differences between transmission and distribution cash flow timing issues that necessitates a modification of the PTRM specifically for distribution regulation; and
- adjustments to more accurately model cash flows unnecessarily increases the administrative burden and modelling complexity and cannot be justified and may indeed infer a level of precision which is not shared with the model inputs.

F. Capital Contributions

The AER seeks comment on how the PTRM could be modified to recognise the treatment of capital contributions, or whether it may be more suitable to deal with this during the reset process.

ETSA Utilities supports a national approach to the treatment of capital contributions within the national regulatory framework. Furthermore, we agree with the AER, that for initial reset transitional arrangements, it may be necessary to give effect to the current jurisdictional arrangements.

The Issues Paper identified an approach to future capital contributions, adopted in Queensland where the QCA includes the value of contributions in the RAB and nets these contributions from regulated revenues. The QCA approach requires an ex-post review of actual capital contributions compared with that forecast. Any differences are then corrected by way of an “unders and overs” adjustment to revenues in the following regulatory period. In our opinion, this type of ex-post review sits uncomfortably with the national regime that stresses ex-ante forecasts of revenues and capital expenditure.

Further, the QCA approach has significant cash implications, significantly impacting on borrowing requirements and credit ratios. Furthermore, reducing capital contributions from revenue artificially reduces current network tariffs below the cost of the service.

This not only distorts the efficient use of the network but it also places an inappropriate burden on future customers.

Having regard to the likely jurisdictional issues, the treatment of capital contributions should initially, in our view, be considered in the reset process. ETSA Utilities considers for the reasons stated that the QCA approach is inappropriate.

G. Forms of Control

Under the NER, the form of revenue controls is determined in the Framework and Approach paper, some 6 months before the distributor is required to make its regulatory submission to the AER. Incorporating three separate x-factor calculations into a revenue model after the form of control has been determined is of little use.

ETSA Utilities considers that the PTRM should be used to quantify the revenue building blocks only, and that the application of the revenue controls be incorporated separately on a distributor-by-distributor basis as part of the Distributor’s submission.

The PTRM should not include three indicative X-factor calculations as the form of revenue control is determined as part of the AER’s Framework and Approach paper six months prior to the distributor’s submission. The distributor’s submission to the AER should demonstrate compliance with the form of revenue control determined in the Framework and Approach paper.

H. Linkages with Information Requirements

In moving to a national framework and national regulator there is likely to be significant information requirements on DNSPs, particularly for those transitioning from a pre-tax to post-tax regulation.

In relation to the transition, it is important that consideration is given to information availability, the format of existing information (which has been developed in consultation with jurisdictional regulators) and the capacity to modify that information. The AER should give appropriate regard to these issues in the reset process. For example, we suggest that the AER could hold discussions with the distributors individually on how information may be provided, and engage with the distributors early in order to be able to obtain relevant and appropriate information from existing information systems that meet the information requirements of the AER, whilst maintaining an efficient process without increasing the cost of regulation unnecessarily.

As the AER itself notes on page 6 of the Issues Paper *"... the information requirements for the AER's first revenue resets in each jurisdiction will most likely be aligned with current jurisdictional arrangements rather than conform to a nationally consistent framework from the outset."*

In developing information requirements regard should be had to information availability, the format of existing information systems and the capacity to modify that jurisdictional information. This is an important issue in transitioning to a national regime and accordingly appropriate consideration should be given to these issues in the reset process.

2.2 Roll-forward Model (RFM)

In principal, ETSA Utilities considers that the transmission RFM provides an appropriate basis for the development of the distribution RFM provided that consideration is given to distribution specific issues, some of which are discussed in this response, such as customer contributions.

The Issues Paper identifies one of the key features in the transmission RFM being that actual depreciation for the period is rolled into the closing RAB, rather than forecast depreciation. Prima facie, there are no distinguishing features in this regard that would justify a different approach in the context of a distribution RFM. The use of actual depreciation is particularly appropriate if this methodology was previously applied by the jurisdictional regulator.

That said, it is important to recognise that pursuant to Schedule 6.2.1(e)(5), the rules do allow the DNSP to propose regulatory or actual depreciation in the roll forward calculation and this requires recognition by the AER. There may well be valid reasons why it is appropriate for a DNSP to propose regulatory depreciation including, for example, consistency with the methodology that was previously applied by the jurisdictional regulator.

Accordingly, the RFM for distribution should be developed with sufficient flexibility to enable the roll forward to be undertaken using regulatory depreciation if this can be supported by the DNSP.

The AER also remarks in the Issues Paper:

> *"Regardless of transitional requirements, the AER may consider the use of existing jurisdictional models for other DNSPs for their first distribution determinations under the amended chapter 6."*

ETSA Utilities supports the use of existing jurisdictional models in a transition process, unless it is shown that there are material errors in these models. We note that the transmission PTRM and RFM have been made available to the public. If the RFM from a particular jurisdictional regulator was to be applied in the initial reset we consider that it would be appropriate that the model be disclosed to the relevant distributor in order that all relevant information is shared in an open and cooperative fashion.

This approach has a significant advantage in that it provides the DNSP with increased regulatory certainty as to how the roll forward will occur in the transition to a national framework. In our view, the issue of certainty takes on added importance when establishing the opening regulatory asset base for the first regulatory control period that is to be administered by the AER.

The transmission RFM provides an appropriate basis for the development of the distribution RFM, provided that consideration is given to distribution specific issues. In addition, the RFM for distribution should be developed with sufficient flexibility to enable the roll forward to be undertaken using regulatory depreciation if this can be supported by the DNSP. ETSA Utilities also supports the use of existing jurisdictional models in a transition process, unless it is shown that there are material errors in these models.

2.4 Efficiency Benefit Sharing Scheme (EBSS)

A. Similarities with the Approach to Transmission Networks

The AER's position as stated in the Issues Paper is that the EBSS applied to the operating expenditure of DNSPs should be the same as that for transmission networks.

This measures the incremental efficiency gains (losses) in a given year equal to the difference between the actual and forecast spend in that year and the actual and forecast spend in the previous year. In our view, it is reasonable to apply to DNSPs an EBSS with this same general approach.

The AER goes on to remark:

> *"Where possible an EBSS should also focus on costs that are controllable by network businesses. For this reason the transmission EBSS allows for forecasts and/or out-turn costs to be adjusted for changes in capitalisation policy and changes in demand compared to the forecast. The transmission EBSS allows certain cost categories to be excluded from the scheme if these cost categories have been accepted by the AER as being uncontrollable in the determination at the beginning of the regulatory period. It is expected that similar arrangements would apply in the EBSS for distribution networks."*

We agree. An important design feature of an effective EBSS is that it should focus on costs that a DNSP can control. It is therefore important to adjust forecasts for changes such as demand forecasts and to exclude uncontrollable costs.

The design characteristics of the operating EBSS, that applies to transmission, should also apply in the EBSS for distribution networks.

B. For DNSPs Efficiency Gains and Losses Should be Applied Symmetrically

The Issues Paper considers the matter of efficiency losses with the AER commenting that:

> *"For DNSPs, it is anticipated that efficiency gains and losses would be applied symmetrically. That is, all carryover amounts, both positive and negative, would be applied.*
>
> *A DNSP operating under an appropriately designed EBSS should not perceive a material advantage in deferring a potential efficiency gain. That is, the DNSP should face an essentially constant benefit (cost) from an efficiency gain (loss) as it arises."*

ETSA Utilities does not consider it good regulatory practice for negative carryovers to apply. Such a decision places an additional penalty on businesses in circumstances where the 'perceived' inefficiency may not be due to poor performance. This will potentially impact, not only on the financial viability of the DNSP, but encourage DNSP to make choices that may not be in the short or long term interests of consumers.

The expectation that a DNSP may have incurred additional expenditure that may be regarded unfavourably by a regulator and result in a further penalty (because it is above a previously determined allowance) may negatively influence the behaviour of that business, again in a way which may not be in the consumers best interests.

The assumption that underpins a negative carryover scheme is that the DNSP was inefficient when there are incremental increases in operating expenditure even when the actual expenditure is below the benchmark allowances. There are other factors which may lead to incremental cost increases other than what may be simply described as being inefficient. For example, the original forecasts may have indeed referred to assumptions that no longer hold true.

The reality is that some outcomes will be management induced and some the result of external factors. It is of course very difficult to distinguish between the two.

It may be that labour costs have risen at a rate greater than expected despite the efforts of management, it may be world-wide insurance pricing matters, or it might be a change in the failure and maintenance rates of equipment. There can also be seasonal outcomes from weather that can significantly increase storms, affecting restoration and repair costs.

All of these can cause a long term change in underlying costs which, under a negative efficiency carryover arrangement will affect the financial viability of a business, and may impact negatively on the decision process to spend funds in the short term to meet service requirements.

The application of negative carryovers is to impose a penalty on the DNSP even if it is these external events that have driven the increase in electricity distribution costs. Should the regulator apply negative carryovers, then this compounds the financial viability issues for DNSPs, as expenditures would have to be undertaken with no financial return for over five years.

This is a policy based on the theory that forecast expenditures will always reflect efficient expenditures in practice. We believe that this does not represent good regulatory policy or encourage appropriate business behaviour. ETSA Utilities considers that there are sufficient business and financial incentives to control expenditure, and that regulatory incentives to not operate as efficiently as possible are not only unnecessary but increase the risk of poor service delivery.

ETSA Utilities considers that in no circumstance should a net negative carryover apply to a regulatory period and that the debate (if any) should only consider whether negative carryovers can be applied to future positive amounts. To do otherwise, would mean that a DNSP would earn less than its efficient revenue in the following period.

The position is more concerning with respect to current period 'efficiency losses'. These 'losses' should be, at worst, quarantined and applied against future positive amounts, particularly where:

- a DNSP is more than two years into a DNSPs regulatory period, providing the DNSP with limited time to respond to the incentives proposed by the regulator; and just as importantly where

- the current period EBSS mechanism does not allow for any adjustments with respect to matters such as changes to demand forecasts and the exclusion of costs deemed to be uncontrollable. This is consistent with the position of the AER as stated in September 2007 (Electricity transmission network service providers EBSS):

  > *"The AER believe that it is not appropriate when determining the efficient operating expenditure allowance for future regulatory control periods to relate future targets to past outcomes on a purely mechanistic basis".*

For the reasons stated, ETSA Utilities does not consider it appropriate for a net carryover to be applied to a regulatory period and that the debate (if any) should only consider whether negative carryovers can be applied to future positive amounts. To do otherwise would mean that a DNSP would earn less than its efficient revenue in the following period. If the AER is still minded to apply negative carryovers, then this should only apply to efficiency losses incurred from the first regulatory period under the AER's jurisdiction.

C. Extension of EBSS to Capital Expenditure

Capital expenditure is one of four separate areas where efficiency incentives may be applied to distributors. Operating expenditure has been discussed above. Schemes can also apply to Demand Management and Service Incentives (SI). These schemes are often considered individually, but they have significant interactions between each. There can be opex/capex trade-offs, the possible use of capex to improve SI and the use of opex payments to defer capex through demand management.

ETSA Utilities has identified three objectives that should be used to evaluate the design of efficiency carryover mechanisms:

- the mechanism should provide a simple, easy to understand and effective incentive that applies continuously to the business to outperform the benchmark targets set for that reset;
- customers should benefit from this outperformance in the longer term through lower prices and/or better service; and
- the mechanisms should not result in perverse outcomes that are long-term materially significant.

The simple capex efficiency carryover mechanism used by ESCOSA has limitations as it does not perfectly mimic the benefits of opex efficiency arrangements, and so affects the opex/capex trade-off incentive. However, the ESCOSA capex EBSS is vastly superior to having no capex EBSS in terms of managing that opex/capex trade-off, and indeed the SI scheme/capex trade off as well.

ETSA Utilities encourages the AER to consider the four potential schemes (opex, capex, demand management and service incentive) as part of an overall package aimed at delivering better long-term outcomes for customers and distributors. It may be that better schemes can be developed. However, a deficiency in a minor aspect of a scheme should not result in the immediate discounting of that scheme. It is quite probable that such a scheme is superior to the alternative outcomes promoted by having no scheme at all.

The inter-relationship of these schemes and their application can vary with each distributor, providing an opportunity for the AER to address the optimum arrangements on a distributor-by-distributor basis through the Framework and Approach paper. This is likely to be particularly so, as arrangements transition through to be nationally consistent.

ETSA Utilities considers that a capex EBSS is an essential complement to the opex EBSS, the SI Incentive scheme and the Demand Management initiatives. These matters are inter-related and require a co-ordinated approach to ensure distributors have an incentive to outperform benchmarks for the long-term benefit of customers. It may be possible for the AER to develop arrangements which improve the quality of the incentives. However, the current arrangements applying in South Australia (ie including a capex EBSS) are superior to those without such a scheme. A tailored distributor-by-distributor approach could be undertaken by the AER through the Framework and Approach papers.

D. Impact of the EBSS on Incentives to Undertake Demand Side Responses and Invest in Distributed Generation

See our response (above) in relation to the need for a capex EBSS and the interaction with Demand Management.

E. Extension of EBSS to Distribution Losses

The Issues Paper considers that there is an economically efficient level of distribution losses, and recognises the variety of factors that can impact on losses. ETSA Utilities would agree that the cost of losses should be included in the evaluation of network augmentations and expansions, in line with good electricity industry practice. However, the simple conclusion, that low losses is a sign of a more efficient electricity distribution system, does not apply. Gas distribution is a sealed pipe where losses can be avoided. In electricity distribution, losses occur in a number of areas but in particular they increase as a square of the level of current.

Consider two distribution systems. One has a significant air-conditioning load and requires more network capacity to meet an occasional peak. Generally, the system runs at a low level of total system capacity. The other network has a milder climate with minor air-conditioning load. As a result, there is less network capacity installed and the system is able to run more consistently at a higher level of system capacity. The first system will have the higher distribution cost (because of the additional and rarely used capacity) but will have lower distribution losses (because the system is operating on average at a lower percentage of total capacity available).

Which of the two systems is more efficient? More importantly, what are the incentives that result if an expensive peaky load network is able to have some demand management deployed to defer network augmentation?

The likely outcome is that the network will become more efficient (lower cost) but will have higher distribution losses because the network will (on average) operate at a higher percentage of the installed capacity.

ETSA Utilities does not consider that a distribution losses incentive scheme is an economically sound policy. We agree that the cost of losses should be included in the evaluation of network augmentation and expansion alternatives.

F. Sharing of Efficiency Gains between DNSPs and Customers

In a market situation, the low-cost producer (ie operating at or near the efficiency frontier) is able to retain a greater proportion of efficiency gains than the less efficient operator. The low-cost producer also has less opportunity to offset unexpected cost-increases that could apply equally to all producers by undertaking further efficiencies. The relative efficiency of a distributor needs to be considered when determining what a fair-sharing of efficiency gains is and how any negative outcomes are applied. This is a complex issue which requires further consultation. It may well be that a distributor-specific approach is warranted which could be undertaken through the Framework and Approach papers.

The benefits of efficiency gains have been shared at quite different rates between customers and distributors. Examples include:

- Price reset requirements for efficiency gains have previously been factored into building block forecasts by jurisdictional regulators. This has inappropriately delivered 100 percent of these benefits to customers; and

- Demand Management initiatives by distributors can result in some deferral of capex within the distribution system that are shared with customers. They can also lead to reductions in transmission and peak generation demands. Current arrangements have customers capturing 100 percent of any TUoS and wholesale price improvements resulting from demand management.

Any consideration of the fair sharing of efficiency gains needs to incorporate all benefits to customers, including those incorporated into the Reset and those that flow from up-stream markets.

The sharing of efficiency gains between customers and distributors needs to consider the relative efficiency of the distributor. More favourable arrangements are warranted for those distributors that are already operating at or near to the efficiency frontier.

The fair-sharing between customers and distributors needs to consider all savings, including any savings incorporated into forecast building blocks by regulators and savings in up-stream markets (transmission and wholesale electricity) through demand management.

These arrangements can vary from distributor to distributor, making the use of the Framework and Approach papers, to determine unique distributor arrangements, a desirable option for the AER.

Please contact me on (08) 8404 5694 should you have any queries in relation to this submission.

Yours sincerely

Eric Lindner
General Manager Regulation and Company Secretary