Issues Paper

Guidelines, models and schemes for electricity distribution network service providers

November 2007

AUSTRALIAN ENERGY REGULATOR

Request for submissions

Interested parties are invited to make written submissions to the Australian Energy Regulator (AER) on the issues discussed in this paper by the close of business Friday 1 February 2008. Submissions can be sent electronically to AERInquiry@aer.gov.au. Alternatively, written submissions can be sent to:

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The AER prefers that all submissions be in an electronic format and publicly available, to facilitate an informed, transparent and robust consultation process. Accordingly, submissions will be treated as public documents and posted on the AER's website, www.aer.gov.au except and unless prior arrangements are made with the AER to treat the submission, or portions of it, as confidential.

Any enquiries about this issues paper, or about lodging submissions, should be directed to the AER's Network Regulation South Branch on (03) 9290 1444 or at the above email address.

Contents

Shortened forms

ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
Capex	Capital expenditure
DNSPs	Distribution network service providers
EBSS	Efficiency benefit sharing scheme
ECM	Efficiency carryover mechanism
ESCOSA	Essential Services Commission of South Australia
ESCV	Essential Services Commission of Victoria
MCE	Ministerial Council on Energy
NER	National Electricity Rules
NPV	Net present value
Ofgem	Office of Gas and Electricity Markets
Opex	Operating and maintenance expenditure
PTRM	Post-tax revenue model
QCA	Queensland Competition Authority
RAB	Regulatory asset base
RFM	Roll-forward model
TNSPs	Transmission network service providers
WACC	Weighted average cost of capital

1 Introduction

1.1 Background

The Australian and state and territory governments have agreed in the Australian Energy Market Agreement (AEMA) to establish a national framework for, among other things, the economic regulation of electricity distribution networks. The Ministerial Council on Energy (MCE) has prepared legislation and rules to give effect to the national framework, which include amendments to the National Electricity Law (NEL) and the National Electricity Rules (NER). Further information about these amendments is available through the MCE's website at http://www.mce.gov.au/.

The amendments are expected to take effect from 1 January 2008 at which time the Australian Energy Regulator (AER) will be responsible for economic regulation of electricity distribution networks within the national electricity market (NEM). This responsibility will include regulating the prices and revenues of electricity distribution network service providers (DNSPs) after the current determinations of state and territory regulators have finished their terms. The timing for the AER's first revenue determinations in each jurisdiction is expected to be as follows:

State / Territory	**AER revenue determination to apply from:**
New South Wales	1 July 2009
Australian Capital Territory	1 July 2009
South Australia	1 July 2010
Queensland	1 July 2010
Victoria	1 January 2011
Tasmania	1 July 2012

After the amended NER come into effect, the AER will begin implementing a number of processes required by the NER in relation to national regulation of electricity distribution networks.

The NER provide the framework for these processes and determine, among other things, the AER's obligations in the administration of the new distribution regime and the scope of the AER's role. This will include obligations on the AER to publish:

- a post-tax revenue model (PTRM);
- a roll-forward model (RFM); and
- cost allocation guidelines

for electricity distribution regulation within six months of the amended NER commencing.

Under the NER, the AER will also be required to publish:

- an efficiency benefit sharing scheme (EBSS); and
- a service target performance incentive scheme.

A specific time frame for the publication of these schemes has not been set in the NER.

In addition, the AER will have the discretion to publish other guidelines and schemes that are relevant under chapter 6 of the NER.

It is noted that under the transitional arrangements in the NER applicable to the AER's first revenue determinations, the AER will be required to implement and have regard to specific arrangements for particular jurisdictions for these determinations. Information about the transitional arrangements in the NER will be available on the MCE's website.

1.2 Consultation and development process for the distribution guidelines, models and schemes

This issues paper is intended to elicit comments from interested parties on how the development of the guidelines, schemes and models discussed in this paper, as well as any other relevant guidelines and schemes, can best support the transition to a nationally consistent framework for economic regulation of electricity distribution networks.

In considering the development of these guidelines, schemes and models, the AER has had regard to the approach taken for the suite of guidelines it has developed for the regulation of electricity transmission networks. The amended NER (chapter 6) for regulation of distribution networks have built on the approach to regulation of transmission networks in chapter 6A of the NER, but have taken into account differences in the nature of transmission and distribution networks. The AER is similarly mindful of these differences and the need to tailor guidelines, schemes and models for the purposes of distribution regulation, where appropriate to do so. Stakeholders making submissions to this issues paper may want to consider the AER's transmission guidelines, schemes and models and their applicability to distribution services when developing their submissions. The transmission guidelines, schemes and models are available on the AER's website. The website also contains copies of submissions from interested parties and information about the AER's consultation process and its final decisions regarding the development of transmission guidelines.

The release of this issues paper is part of a preliminary consultation process which is being undertaken by the AER in the lead-up to commencing its new role in the national regulation of electricity distribution networks and is not a formal process under the NER. The AER's approach to consultation was previously set out in its paper, Electricity Distribution Regulatory Guidelines – Statement of Approach released in September 2006, although the timeframe for consultation has been revised to reflect the current timing of amendments to chapter 6 of the NER.

As part of this preliminary consultation process, the AER has also released a separate issues paper on the development of a service target performance incentive scheme and has invited written comments on that issues paper, which is available on the AER's website.

In accordance with the formal consultation procedures in the NER, the AER will be undertaking further consultation in 2008 on the proposed guidelines, scheme and models discussed in this paper, a service target performance incentive scheme, and other guidelines and schemes relevant to chapter 6 of the NER that the AER is considering.

Consistent with the approach to consultation on DNSP regulatory arrangements outlined by the AER in its previous Statement of Approach paper, the AER is undertaking preliminary consultation now to inform it in the development of the guidelines, schemes and models for distribution regulation and to provide stakeholders with an opportunity to provide input and comments prior to the AER formally setting out its proposed or draft positions in relation to the set of guidelines, schemes and models for consultation under the requirements of the NER. Stakeholders are encouraged to provide submissions during this preliminary consultation and may want to take the opportunity to canvass both threshold issues and issues of detail at this stage. It is noted that under the NER, the time period for formal consultation will generally be limited to 80 business days. As part of that future consultation process, the AER will publish draft guidelines, schemes and models, with accompanying explanatory statements, and seek written comments from interested parties.

This issues paper has been prepared by AER staff with input from consultants advising the AER on the development of the regulatory arrangements for electricity distribution. This issues paper should not be taken as indicating any particular views by the AER Board in relation to distribution regulation.

1.3 Revenue determinations for NSW and ACT for 2009-2014

Chapter 6 of the NER will not apply to the AER's first electricity distribution determinations for NSW and the ACT for the period commencing 1 July 2009, as these determinations will be made in accordance with separate transitional arrangements under the NER. The AER has released separate consultation papers in relation to these resets which are available on the AER's website. The suite of guidelines that will apply to the forthcoming NSW and ACT resets are separate from those discussed in this paper and have been established in accordance with the requirements of the transitional provisions. It is noted, however, that DNSPs in NSW and the ACT will in the future be subject to chapter 6 of the NER and the suite of guidelines discussed in this paper, consistent with the arrangements outlined in the NER.

1.4 Process and timing for future consultation

For the guidelines, schemes and models that the AER intends or is required to publish by mid-2008 (on the basis that the amended NER take effect from 1 January 2008), it is envisaged that the AER's consultation process under the NER would commence in March 2008 and conclude in June 2008.

The guidelines, scheme and models discussed in section 2 of this issues paper, and the service target performance incentive scheme, incorporate the key elements of the distribution guidelines 'package' that the AER will be required to publish by mid 2008 (on the basis that the amended NER take effect from 1 January 2008) and those elements that the AER intends to publish by then.

1.5 Relationship to framework and approach process

Under the NER, it will be necessary to have the guidelines, scheme and models discussed in section 2 of this issues paper, and the service target performance incentive scheme, in place by mid-2008 if the AER is to meet certain obligations under the NER to prepare framework and approach papers in 2008 for the Queensland and South Australia revenue reset processes. Specifically, the NER will require the AER to commence consultation on its framework and approach papers for these resets at least 24 months before the end of their current 2005-10 regulatory period (i.e. by 1 July 2008) and complete preparation of these papers at least 19 months before the end of that regulatory period (i.e. by 1 December 2008). DNSPs in these jurisdictions will be required to submit their revenue applications by May 2009. It is noted that the framework and approach, and reset, processes, will commence for DNSPs in Victoria six months after these processes commence for DNSPs in Queensland and South Australia.

Under the NER, the purpose of the framework and approach papers is to set out the AER's approach for a forthcoming DNSP revenue reset to the control mechanism (price/revenue) and the classification of services (direct/negotiated). In addition, the framework and approach paper will set out the AER's views on the application of an EBSS and a service target performance incentive scheme to the DNSP in question.[1] The publication of these schemes by mid-2008 is therefore necessary if their specific application to the Queensland and South Australia resets is to be considered through the framework and approach processes for these resets.

As noted above, publication of a PTRM, a RFM and cost allocation guidelines will also be required under the NER by the end of June 2008 assuming that the amended NER take effect from 1 January 2008. These matters are not directly covered by the framework and approach process.[2]

1.6 Other guidelines, schemes and information requirements

Under the NER, the AER may develop other guidelines and schemes for DNSPs relevant to chapter 6, including the following:

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[1] And a demand management incentive scheme if applicable. This is discussed further below.

[2] The AER will be required to review WACC parameters for TNSPs and DNSPs in 2009, however, this process is also separate to the framework and approach process.

- demand management incentive scheme
- classification of distribution services
- control mechanisms for direct control services.

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.

It is noted that the purpose of the framework and approach process is also to set out the AER's likely approach to the classification of services for revenue resets and the form of price control that is to be applied for the reset determination. Although the AER may publish separate guidelines in relation to these matters at any time, such guidelines are not proposed in 2008 as it is considered that the specific issues regarding the classification of services and form of price control for the Queensland and South Australia resets can be more appropriately addressed through the framework and approach processes.

In the transition to a national framework for electricity distribution regulation, there are likely to be a range of issues that may be more appropriately addressed initially through framework and approach processes rather than through national guidelines. For example, 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. The framework and approach process would appear the more appropriate mechanism to apply these requirements in individual resets. Similarly, while the transition from pre-tax to post-tax regulation is an issue on which some DNSPs will require the AER’s guidance, it may be more appropriate to provide this guidance through the framework and approach processes rather than through a national guideline given that this issue will affect particular DNSPs.

Demand forecasting methodology is another important aspect of the revenue reset process. As there are varying demand forecasting methodologies currently adopted by DNSPs, there is likely to be merit in the development of national guidelines outlining what the AER considers to be best practice. Such guidelines would help to ensure that DNSPs undertaking demand forecasts for their resets adopt an approach that has been the subject of public review and is the most robust methodology available. At this stage it is proposed that these matters would initially be addressed through the framework and approach process for the upcoming resets, before consideration is given to developing a national approach.

The AER’s future annual reporting and other information requirements is a further matter to be addressed. These requirements will cover, among other things, financial and service performance information as well as information about a DNSP’s capital and operating expenditure. Many of these requirements are specified in the NER and the AER will collect this information through Regulatory Information Notices and Regulatory Information Orders issued under the NEL. The AER’s new annual reporting requirements will be considered in due course and the AER is mindful that there must be sufficient time allowed to DNSPs to modify their reporting systems, as appropriate, to be able to report under a new national approach. This work on a national approach will be progressed in 2008 but is not expected to be completed at the same time as the guidelines, schemes and models discussed in this paper, which are particularly relevant to the next resets.

In the meantime, it is proposed that the AER's information requirements for its first revenue resets in each jurisdiction will generally align with the current state and territory information and reporting arrangements. To that extent, the requirements which will be relevant to the next reset for each DNSP will be developed initially as part of each DNSP's framework and approach process.

The AER will be giving further consideration to these issues and to the development of other guidelines, schemes and information requirements to support the transition to a national framework for economic regulation of electricity distribution networks. It is proposed that further consultation papers canvassing these issues will be released by the AER in 2008.

1.7 Structure of this paper

This issues paper is structured as follows:

- section 2 discusses the:
  - post-tax revenue model
  - roll-forward model
  - cost allocation guidelines
  - efficiency benefit sharing scheme

  in terms of their basis in the NER and objectives, the specific approach proposed and issues for their development, and their relationship with other processes under the NER regarding revenue resets

- section 3 provides a consolidated list of the specific issues raised in this issues paper.

1.8 Next steps

Interested parties are invited to make submissions to the AER by the close of business Friday 1 February 2008. These submissions will be published on the AER's website. It is also intended that a public forum be held in February following the receipt of submissions to enable interested parties to discuss their views in an open forum and raise matters directly with the AER.

On the basis that the amended NER take effect from 1 January 2008, the AER will commence consultation under the NER in March 2008 on those guidelines, schemes and models that the AER intends or is required to publish by mid-2008.

2 Models, guidelines and EBSS

2.1 Post tax revenue model

2.1.1 Basis and policy objectives

A core element in the regulation of electricity distribution networks is the establishment of the post-tax building block revenue requirement. Consistent with the approach used in electricity transmission, chapter 6 of the NER prescribes the development of a model by the AER that is to be used to perform building block calculations. This PTRM contains detailed calculations that are not amenable to prescription in the NER but are able to be developed and applied by the AER to all DNSPs. The NER provisions relevant to the PTRM for distribution are largely identical to those in the transmission rules and are briefly outlined here.

Clause 6.4.1 requires the AER to publish a PTRM within 6 months after the commencement of the amended chapter 6. Revenue proposals submitted by DNSPs must be prepared in accordance with the PTRM under clause 6.3.1(c).

The PTRM must include at least:

- a method that the AER determines is likely to result in the best estimates of expected inflation
- the timing assumptions and associated discount rates that are to apply in relation to the calculation of the building blocks referred to in clause 6.4.3
- the manner in which working capital is to be treated
- the manner in which the estimated cost of corporate income tax is to be calculated.

Clause 6.4.3 states that the annual revenue requirement comprises of the following components:

- indexation of the regulatory asset base (RAB)
- a return on capital
- depreciation (return of capital)
- the estimated cost of corporate income tax
- any revenue increments or decrements arising from the efficiency benefit sharing scheme, service target performance incentive scheme and demand management incentive scheme
- any revenue increments or decrements arising from the application of control mechanisms in the previous regulatory control period
- forecast operating expenditure (opex).

Indexation, depreciation and returns on capital involve the RAB, which is calculated under schedule S6.2. Clause S6.2.3 prescribes the method by which the RAB is valued for each year of the regulatory period, namely that it is rolled forward by adding forecast capital expenditure (capex), subtracting forecast depreciation and disposals and adjusted for inflation. The indexation of the RAB is designed to maintain the real value of the RAB from one year to the next.

Clause 6.5.5(b) provides that depreciation must be calculated such that:

- the depreciation profiles reflect the economic life of that asset or asset category
- the sum of real depreciation over the life of the asset is equal to the value at which the asset was first recognised for regulatory purposes
- the lives, depreciation method and rates used in calculating forecast depreciation must be consistent with those actually applied during that regulatory period.

Whereas the PTRM for transmission (clause 6A.5.3) must specify the maximum allowed revenue (MAR) and X factors, the PTRM for distribution is not required to specify values for the price or revenue control mechanism.

Q. The AER seeks comment on whether other rule provisions exist that are relevant to developing the PTRM for electricity distribution.

Q. Comments are also invited on whether the provisions mentioned here may require a different approach or have different meaning in the context of distribution and transmission regulation.

2.1.2 Consistency between the PTRM for transmission and distribution regulation

The NER provisions outlined above relating to the building block calculation and the contents of the PTRM are almost identical between distribution and transmission. Accordingly, it is anticipated that the PTRM developed by the AER for transmission regulation can be used as a basis for distribution regulation. Stakeholders may wish to examine the AER's considerations in developing the PTRM for transmission in the context of distribution. These considerations are briefly summarised below and are discussed in more detail in the AER's decision documents for transmission networks which are available on the AER's website.

- Depreciation methods – the PTRM uses straight line depreciation which is regarded by the AER as being compliant with clause 6A.6.3(b). 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.
- Capex recognition – the PTRM depreciates assets from when they are commissioned while returns on capital are calculated from when capex is incurred. This hybrid approach is also regarded by the AER as being compliant with the amended chapter 6 because depreciating assets on an as-commissioned basis ensures that businesses recover the cost of assets from when they first contribute to service delivery. The AER will consider proposals using a full 'as-incurred' approach although it considers that a full 'as commissioned' approach is not consistent with the NER.

- Inflation bias – several gas and electricity review processes have identified issues with the use of Commonwealth Government securities in estimating forecast inflation. At present the PTRM requires inflation as a direct input although this may be amended when the AER considers this issue in the review of WACC parameters under the NER in 2009.
- Cash-flow timing – due to the modelling of cash-flows on an annual basis, the PTRM assumes that all cash-flows except for capex occur at the end of each regulatory year. In relation to transmission networks, the AER noted that it intended to consider these timing assumptions further and may amend the PTRM under the guideline amendment process in the future.

Q. The AER seeks comment on whether the PTRM developed for electricity transmission provides a suitable basis for distribution regulation.

Q. If not, what particular features or aspects of the PTRM need to be amended?

2.1.3 Distribution specific issues

Three specific issues have been identified in considering the application of the transmission PTRM to distribution, namely the treatment of capital contributions, the control mechanism and cash-flow timing issues.

2.1.3.1 Capital contributions

Clause 6.21.2 provides guiding principles in relation to contributed assets:

- the DNSP is not entitled to recover asset related costs for assets provided by network users
- the DNSP may receive a capital contribution, prepayment and/or financial guarantee up to the future revenue related to the provision of services for any new assets installed as part of a new connection or modification to an existing connection, including any augmentation to the distribution network
- where assets have been the subject of a contribution or prepayment, the DNSP must amend its revenue related to the provision of direct control services.

The treatment of capital contributions for regulatory purposes differs between jurisdictions. For example, the approach adopted by the Essential Services Commission of Victoria (ESCV) has been to deduct the value of contributed assets from the RAB and to recognise the value received as income for calculating tax liabilities. The Queensland Competition Authority (QCA)’s approach has been to include the value of contributions in the RAB and net these contributions from regulated revenues. While a consistent approach would be desirable across jurisdictions and may be achievable over time, specific amendments to the PTRM used by each business may be required for their first resets by the AER, which would have regard to current arrangements and any transitional provisions.

Q. 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 reset processes.

2.1.3.2 Cash-flow timing issues

Jurisdictional regulators employ various cash-flow timing assumptions in modelling revenue requirements. However, in moving towards a national regulatory framework, the AER considers that there is merit in adopting a single set of timing assumptions. 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.

The PTRM for transmission models revenues and expenditures on an annual basis, and revenues and expenditures (with the exception of capex) are assumed to occur on the last day of the regulatory year. Capex is recognised in the middle of each year and earns a half-year return which is capitalised before being rolled into the RAB. This particular timing assumption recognises that capex can occur evenly throughout the year, which is approximated by the middle of the year assumption.

These timing assumptions are internally inconsistent as they make no allowance for the time value of intra-year cash flows, most notably revenues and opex, which are also likely to occur evenly throughout the year. Specifically, the PTRM does not provide compensation to businesses for the opportunity cost of funding opex throughout the year, nor does it recover the time value of cash benefits given that businesses also receive revenues throughout the year.

In addressing this inconsistency, and in assessing the appropriateness of these timing assumptions in general, the AER has considered the competing objectives of achieving greater accuracy in modelling revenue requirements and making the PTRM simple and transparent. In commenting on the transmission PTRM, service providers found the existing assumptions to be pragmatic while users expressed concern over a potential bias in favour of service providers.

In considering these issues, several jurisdictional regulators have recognised working capital allowances to account for cash-flow timings. In 2002 the ACCC engaged Allen Consulting Group (ACG) to consider the need to incorporate working capital into the PTRM.[3] The ACG found that working capital was not necessary and also that the PTRM's timing assumptions tended to overcompensate service providers. Since this report, the PTRM adopted by the AER for transmission has been modified to recognise capex mid year with an additional half year return, which has been to the benefit of service providers.

[3] Allen Consulting Group, Working capital, May 2002. Available from http://www.aer.gov.au/content/index.phtml/itemId/681036.

Improvements to the accuracy of the timing assumptions in the PTRM may be possible through the use of present value adjustments. That is, the annual cash-flow values in the PTRM could be adjusted to reflect the time value benefit and costs of intra-year cash-flows. An example calculation of these present value adjustment factors in the case of opex is illustrated in Table 1 below.

Table 1: Derivation of annual escalation factor for opex, recognising monthly expenditures

Month		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Actual opex		2	2	2	2	2	2	2	2	2	2	2	2
PV, beginning of month 1	23.38												
PV, end of month 12 (a)	24.55												
Simple end of period opex (b)	24.00												
escalator (a) / (b)	1.023												

Notes: assumes annual discount rate of 5%, monthly rate of 0.407%.

In this example, the PTRM would currently use the ‘simple end of period opex’ of \$24.00 whereas the actual cost to the service provider is \$24.55. The escalation factor represents the ratio of these two amounts and is applied to the annual opex amount to derive a present value adjusted expenditure amount. That is, the simple annual opex amount is increased to reflect the time value cost of the monthly expenditures. In the case of revenues, such adjustments decrease the annual value to reflect the benefits already derived from monthly receipts. The net impact on allowed revenues will depend on the particular cash-flow profiles and whether adjustments are applied to all cash-flow items (including tax payments, payments to debt holders etc).

The application of present value adjustments to revenues and opex was explored recently by the ACCC in its draft decision for GasNet.[4] In GasNet’s case, the PTRM’s current timing assumptions (i.e. revenues and opex end of year, capex mid year) would have resulted in an over-recovery of its revenue requirement by 6.8% (in net present value (NPV) terms) over the next access arrangement period. This was reduced to 1.6% with the introduction of adjustment factors.

As suggested by the ACG report and the ACCC’s GasNet decision, the PTRM’s current timing assumptions may result in a material over-compensation of revenue requirements in certain circumstances. If this is the case for other service providers, some adjustments to the PTRM could be made through the addition of present value adjustments as demonstrated above. These adjustments could reflect monthly, quarterly or bi-annual cash-flow profiles.

[4] ACCC, November 2007, GasNet draft decision. Available from http://www.aer.gov.au/content/index.phtml/itemId/716055.

Q. Do the PTRM's current timing assumptions result in any systematic bias in favour of service providers?

Q. If so, is there merit in considering modifications to the PTRM to remove this bias, for example, in the form of present value adjustments discussed here?

Q. To what extent would these adjustments increase the administrative burden and complexity of the modelling?

2.1.3.3 Forms of control

Unlike the equivalent provisions of clause 6A.5.3 for electricity transmission, the NER do not require the PTRM to deal with the calculation of X factors. This is because the form of control mechanism is to be determined by the AER for each DNSP during the framework and approach process and may differ between them. Three general forms of control mechanisms are currently applied, namely revenue caps, weighted average price caps and revenue yields or average revenue caps.

Clause 6.5.9 specifies that all control mechanisms must incorporate a form of CPI-X adjustment. Clause 6.2.6 requires that X be set such that the NPV of the revenue to be earned over the period equals the NPV of a DNSP's revenue requirement for the period. There may be different X factors for each year of the regulatory period and for different standard control services.

Given the likelihood of commonality in the forms of control and specific requirements regarding the calculation of X factors, it may be possible for the PTRM to calculate X factors under the three basic forms of price and revenue control. Such information may be useful for DNSPs and network users by illustrating the methods that may be used in revenue applications and potential impacts on distribution price levels. Such a feature is, however, not necessary and the actual forms of control would need to be developed and applied by each business during the reset process. To this end, it may be preferable to develop a separate pricing model for calculating X factors and for assessing tariffs on an annual basis, including under Part I of chapter 6 of the NER.

Q. Stakeholders are invited to comment on the benefit of incorporating indicative X factor calculations in the PTRM under common forms of price control, namely revenue caps (as per the existing PTRM), weighted average price caps, and revenue yields.

2.1.4 Linkages with information requirements

The inputs and outputs of the PTRM relate to DNSP information requirements in the following ways:

- DNSPs, particularly those transitioning from a pre to post tax building block approach, will be required to substantiate asset values for tax purposes
- DNSPs may need to begin reporting capex on both an as incurred and as commissioned basis

- various adjustments (e.g. to RAB values) may be required in moving from existing to new service classifications under the amended chapter 6
- X factors and information for tariff approvals will need to reconcile with the calculated annual revenue requirements
- at an aggregate level, capex and opex values used in the PTRM will need to reconcile to data provided in revenue submission documents and templates
- asset data inputs will need to reconcile to the methods and values prescribed in the NER, including calculations under jurisdictional methods which may have been set in prior determinations.

Q. Stakeholders are invited to comment on other likely information requirements associated with the PTRM.

2.2 Roll-forward model

2.2.1 Basis and policy objectives

The approach to valuing the RAB of established transmission and distribution networks in the NER is the ‘lock-in’ and ‘roll-forward’ approach. This approach is desirable as it avoids the risk of ex post asset optimisation and provides certainty to investors. The NER require the AER to develop a roll-forward model (RFM) to be used in performing detailed RAB calculations that are not amenable to prescription in the NER.

It is considered that the RFM developed for transmission regulation should be largely applicable to distribution regulation. In addition to the similarities in NER provisions, the AER will seek to apply consistent regulation between the two sectors where possible and desirable. To a large extent, similarities between the distribution and transmission RFM will be dictated by similarities in the respective PTRMs. This is because the RFM will potentially perform the same asset calculations as the PTRM but with actual data in place of the forecasts used in the PTRM.

Many requirements of the RFM are outlined in schedule S6.2. Briefly, this schedule prescribes RAB values for DNSPs at a particular point in time. These values are equal to the RAB determined for the beginning of the current regulatory period for each DNSP. These prescribed RAB values are to be adjusted for the difference between any estimated capex and actual capex included in that value. In doing so, it requires the AER to remove any associated benefit or penalty to the DNSP that would arise from this adjustment.

Clause S6.2.1(e) generally outlines how RAB values are to be rolled forward from the beginning of one regulatory period to the next. This requires, among other things, that the opening RAB be rolled forward by adding actual capex and subtracting depreciation and disposals over that regulatory period. The amount of depreciation must be calculated in accordance with the distribution determination that applied for that period. Clause 6.5.1(e)(3) requires the RAB to be adjusted for actual inflation using a method that is consistent with the indexation of the control mechanism(s) for that regulatory period.

Clause 6.5.5(b) specifies that the depreciation schedules used by the DNSP or the AER must conform to the following requirements:

- each asset (or group of assets) is to be depreciated over its economic life
- the total sum of the allowed depreciation over the asset's life is to equal the initial value at which the asset entered the RAB
- the economic lives, methods and the rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those in the distribution determination for that period.

The final requirement of this clause implies that the depreciation method and parameters in the RFM must be consistent with those approved by the AER and submitted by the DNSP for the forecast regulatory period. This clause, as well as S6.2.1(e)(5), allows the DNSP to propose regulatory or actual depreciation (as it relates to forecast or actual capex respectively) in the roll-forward calculation. The use of actual depreciation, as prescribed in transmission regulation, provides a stronger incentive to underspend capex allowances.

Clause S6.2.3 deals with the roll-forward calculation on an annual basis using forecast capex, depreciation and other amounts set out in distribution determinations. These calculations are currently contained in the PTRM.

Other provisions in schedule S6.2 (which mainly deal with the valuation of assets not previously recognised as providing standard control services) are not intended to be covered by the RFM and are not addressed in this issues paper.

Q. The AER seeks comment on whether other rule provisions exist that are relevant to developing the RFM for electricity distribution.

Q. Comments are also invited on whether the provisions mentioned here may require a different approach or have different meaning in the context of distribution and transmission regulation.

2.2.2 Consistency between the RFM for transmission and distribution regulation

Most of the provisions relating to the RAB in chapter 6 and chapter 6A are identical. However, one area of discretion in the NER may allow a fundamental difference for distribution regulation, in that regulatory or actual depreciation may be applied. As noted above, this has implications for the capex incentive framework and affects the RFM calculations. Nevertheless, it is considered that the RFM developed by the AER for electricity transmission, which uses actual depreciation, can be used as a basis for consulting on the RFM for distribution regulation.

There are four pertinent features of the transmission RFM that should be noted with respect to alternative or existing roll-forward methods:

- like the PTRM, the RFM uses a 'hybrid' methodology, calculating returns on capital as expenditure is incurred, and depreciation from when assets are commissioned
- actual depreciation for the period is rolled into the closing RAB, rather than forecast depreciation
- there is an adjustment for the difference between the estimated and actual capex values in the final year of the immediately preceding period, which also removes the penalty or benefit arising from this adjustment
- there is a roll-forward calculation for the purposes of establishing asset values for tax purposes, which is not prescribed in the NER but is required to generate inputs for the PTRM.

Q. Stakeholders are invited to comment on whether there are any impediments to using the AER's transmission RFM as a basis for the distribution model.

2.2.3 Distribution specific issues

The timing assumptions and methods in the RFM will follow those applied in the distribution determination relevant to that period, most of which will be set out in the AER's distribution PTRM.

In this context, the transmission RFM and the PTRM are based on a hybrid methodology for recognising capex, and use a straight-line, actual depreciation method. These methods are preferred by the AER and considered to be compliant with the NER. Alternative methods of depreciation may be proposed (including for tax purposes) by DNSPs and assessed against the relevant requirements of the NER, most notably clause 6.5.5. In considering the use of actual or regulatory depreciation, the AER will also have regard to section 7A(3) of the NEL which requires effective incentives to undertake efficient investments.

Other assumptions and methods that are common to both models are discussed in the previous section. The AER's conclusions on these issues for transmission regulation are discussed in its decision regarding the RFM developed for transmission.

The AER will develop a general RFM as required under chapter 6 for use in the second round of its distribution determinations. It is expected that the first round of roll-forward calculations made by the AER for each DNSP (e.g. for the period 1 July 2004 to 30 June 2009 for NSW and the ACT) may be subject to transitional provisions that have regard to the incentive frameworks and other arrangements put in place by jurisdictional regulators for those regulatory periods. Aside from any transitional provisions, clauses 6.5.5(b) and S6.2.1(e)(5) require the AER to calculate depreciation in a manner that is consistent with the distribution determination for that regulatory period.

For example, the transitional provisions for the ACT require the AER to apply the method developed by the ICRC, taking into account any representations by the ICRC made before the commencement of the NER amendments. 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. The AER will also consider the appropriateness of applying its RFM should transitional rules allow, as is being done for DNSPs in NSW.

Q. The AER invites comments on whether the adoption of existing models is appropriate and whether there are specific issues regarding these models, and current jurisdictional revenue determinations, that the AER needs to consider in performing its first round of roll-forward calculations in each jurisdiction.

2.2.4 Linkages with information requirements

The AER may consider using annual reporting requirements (including those currently used by jurisdictional regulators) to collect and verify data which will be used in the RFM at the end of each regulatory period. For this purpose the RFM requires annual actual input data on:

- Capex by asset class
- disposals by asset class
- contributed assets by asset class
- inflation
- asset data for tax purposes.[5]

2.3 Cost allocation guidelines

2.3.1 Basis and policy objectives

The cost allocation guidelines applicable to distribution networks will set out arrangements to manage the attribution of direct costs and the allocation of shared costs by DNSPs between and within different categories of distribution services.

Under the NER, DNSPs will have 12 months from when the amended NER commence to submit their cost allocation method to the AER for approval, and the AER has 6 months from receipt of the method to approve it.

Although chapter 6 of the NER does not set out the required contents of the cost allocation guidelines, clause 6.15.3(b)(1) stipulates that the cost allocation guidelines should be designed to give effect to the ‘cost allocation principles’. That is, a DNSP must apply a cost allocation method that only allocates costs to a service:

- according to the substance of a transaction or event rather than its legal form

[5] See AER issues paper entitled “Transition of energy businesses from pre-tax to post-tax regulation”, available on the AER’s website.

- that can be directly attributed or, in the case of shared costs, using an appropriate causal allocator, or where no such allocator exists or costs are not material, using a 'well-accepted' non-causal allocator
- so that the same cost is not allocated more than once. Costs allocated to a particular service must not be reallocated to another service during the course of a regulatory control period.

Under clause 11.14.3, a DNSP that was providing distribution services at the date of the NER amendment will:

- remain subject to the old regulatory regime for the duration of the transitional regulatory period – that is, the DNSP may use their existing cost allocation method to report on information needed for their first revenue reset under the amended chapter 6
- not become subject to the new regulatory regime until the end of the transitional regulatory period.

However, clause 11.14.6 provides that a DNSP subject to the old regulatory regime is still required to apply clause 6.15 of the amended chapter 6 which requires it to:

- submit a cost allocation method to the AER for approval
- apply and comply with the cost allocation method that is approved by the AER.

2.3.2 Proposed approach to the cost allocation guidelines

Consistent with the NER, the AER proposes to adopt the following working assumptions and principles in preparing the cost allocation guidelines:

- the guidelines introduced for the distribution sector should be consistent with those in place for transmission where possible – as cost allocation principles are likely to be similar
- the guidelines will only deal with cost attributions and allocations down to services, not individual prices for different categories of services. Cost allocation for pricing purposes will be dealt with separately, for example through pricing principles statements
- all revenues, costs, assets and liabilities of regulated business will have their origin in statutory accounts, although a single set of regulatory accounts could potentially draw from the statutory accounts of multiple entities
- regulatory requirements take precedence over statutory requirements for regulatory purposes.

Furthermore, the AER expects that the cost allocation guidelines for distribution services will specify:

- the format of a cost allocation method
- the detailed information that is to be included in a cost allocation method

- the categories of distribution services which are to be separately addressed in a cost allocation method, such categories being determined by reference to the nature of those services, the persons to whom those services are provided or such other factors as the AER considers appropriate
- the allocation methods which are acceptable and the supporting information that is to be included in relation to such methods in a cost allocation method
- the required contents of a regulated business's cost allocation method
- the basis on which the AER will assess a regulated business's proposed cost allocation method for approval
- the basis on which the AER will consider proposed changes to a regulated business's cost allocation method over time in order that it be a 'living document'
- how the AER expects the cost allocation method to be applied over time.

As noted previously in this issues paper, DNSPs should also have regard to the transitional arrangements that apply to the AER's first revenue determinations under the amended NER.

For more information about the AER's prospective approach to the distribution cost allocation guidelines, stakeholders may refer to the AER's decision on the transmission cost allocation guidelines and supporting information, which are available on the AER's website.

2.3.3 Linkages with information requirements

It is proposed that the distribution cost allocation guidelines will be a stand alone document. All substantive cost allocation provisions will, as far as possible, be included in the guidelines rather than in other regulatory instruments or guidelines. The exception to this general rule is that arrangements relating to the nature and conduct of regulatory audits, including audits of a DNSP's compliance with its cost allocation method, will be addressed in the AER's future requirements for information reporting by DNSPs.

Q. Written comments from interested parties are sought on the following:

- **Given the similarity between the respective NER provisions for transmission and distribution, to what extent should the AER adopt a similar approach to cost allocation between distribution and transmission businesses?**
- **Are the proposed general principles discussed above for the provision of information for cost allocation in the distribution sector appropriate?**
- **Should any other general principles and or requirements be reflected in the distribution cost allocation guidelines?**

2.4 Efficiency benefit sharing scheme

2.4.1 Basis and objectives

The framework for regulation of electricity distribution networks set out in the amended NER builds on the approach to regulation of transmission networks, taking into account the differences in the nature of transmission and distribution networks.

Accordingly, the requirements for an EBSS applicable to distribution, set out in clause 6.5.8, are substantially similar to those for transmission network service providers (TNSPs), set out in clause 6A.6.5.

The amended NER require that the AER develop and publish an EBSS that provides for a fair sharing of efficiency gains and losses between DNSPs and distribution network users.

The most significant deviation in the amended NER between the distribution and transmission EBSS is that the distribution EBSS may be extended to efficiency gains and losses related to capex and distribution losses. Chapter 6A of the NER specified that the transmission EBSS is to be applied only to opex.

In developing the EBSS, the NER (chapter 6) require the AER to have regard to:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs
- the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce opex and capex (if included in the scheme)
- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses
- any incentives that DNSPs may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

2.4.2 Similarities with the approach to transmission networks

As a general principle, it is considered that an EBSS applied to the opex of DNSPs should be the same as that for transmission networks, unless there are any significant differences in the nature of the incentives facing DNSPs compared to TNSPs that would justify altering the incentives provided by the EBSS.

It is anticipated that the EBSS applying to DNSPs, as for TNSPs, would measure efficiency gains and losses for opex on an incremental basis. That is, the efficiency gain in a given year is equal to the difference between the underspend in that year and the underspend in the previous year. More detailed information about the AER's approach to measuring efficiency gains and losses for transmission networks can be found in the EBSS applying to transmission, which is available on the AER's website.

For DNSPs, it is also 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. Further, the measurement of gains and losses should not be affected by artificial means, such as the shifting of costs between years, and should represent genuine business outcomes that have arisen in the ordinary course of conducting the business in a prudent and diligent manner.

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.

Q. Is it reasonable to apply to DNSPs an EBSS with the same general approach as the transmission EBSS?

Q. Are there any significant differences between transmission and distribution businesses that would require a different general approach?

2.4.3 Differences from the approach to transmission networks

The amended NER allow, but do not require, the distribution EBSS to be extended to efficiency gains and losses related to capex[6] and distribution losses.

Should the EBSS be extended to capex, the AER is required by the NER to have regard to the need to provide DNSPs with a continuous incentive to reduce capex so far as is consistent with economic efficiency. However, this NER requirement, which also applies to opex, does not apply to any extension of the scheme to distribution losses.

Another important requirement of the NER, which will need to be considered when deciding whether to extend the scheme to capex, is the requirement that the AER have regard to any incentives that DNSPs may have to inappropriately capitalise opex. An additional new requirement of the NER as it applies to DNSPs is the requirement that the AER have regard to the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme. The latter clause requires the AER to consider whether or not the EBSS will provide net benefits to consumers.

[6] As noted previously, DNSPs should also have regard to the transitional arrangements that apply to the AER's first revenue determinations under the amended NER.

2.4.4 Treatment of capex

For DNSPs, capex has been included in schemes in place in South Australia and Victoria. The ESCV has stated in its 2006-10 revenue determination, however, that it did not intend for capex to be included in its scheme in the future. The efficiency carryover mechanism operating in Tasmania only applies to opex. No other jurisdictions have rolling carryover type mechanisms that apply to either capex or opex.

An important consideration in deciding whether to apply an EBSS to capex is the balance between the incentives to reduce capex and opex, and the potential gains of substituting expenditure between one type and the other. The following discusses these issues in more detail.

2.4.5 Nature of capex

The nature of capex, and its role in the building block calculation, means that a scheme applying to capex should be designed differently to a scheme applying to opex.

As for opex, the incentive to reduce capex is not constant over the regulatory period. However, the reason for this changing incentive is different for capex than it is for opex. In calculating revenues, forecast capex is incorporated into the RAB and a DNSP receives a return on that forecast capex during the period, even if that capex forecast is not spent. At the next reset any unspent forecast capex is removed from the RAB under the RFM, but the DNSP retains the return on the forecast capex that it received during the previous regulatory period. Therefore, if a DNSP underspends its capex at the beginning of the regulatory period, it receives the return on the unspent forecast capex for more years than if it underspends its forecast capex in the latter years of the period. To address this inconsistency, carryover mechanisms incorporated in the South Australian and Victorian regulatory arrangements have measured the efficiency gain/loss for capex on a cumulative basis. That is:

$$E_t = (F_t - A_t) \text{ x WACC}$$

where:

E_t is the efficiency gain/loss in year t

A_t is the actual, or adjusted actual, capex incurred in year t

F_t is the forecast, or adjusted forecast, capex accepted or substituted for year t

WACC is the weighted average cost of capital.

The efficiency gain or loss is then carried over for five years after the year of the capex underspend/overspend, as demonstrated in the following table.

Table 2: Carryover of efficiency gains/losses

Year, t	1	2	3	4	5	6	7	8	9	10
Forecast capex, F_t	100	103	105	99	98					
Actual capex, A_t	97	96	97	94	98*					
Efficiency gain, E_t	0.17	0.40	0.45	0.28	0					
Carry over										
Year 1		0.17	0.17	0.17	0.17	0.17				
Year 2			0.40	0.40	0.40	0.40	0.40			
Year 3				0.45	0.45	0.45	0.45	0.45		
Year 4					0.28	0.28	0.28	0.28	0.28	
Year 5						0.00	0.00	0.00	0.00	0.00
Total carry over amount						1.30	1.13	0.74	0.28	0.00

* This value is assumed as final year capex but is not known at the time of the revenue determination.

Note: assumes a real WACC of 5.66%

An important consideration regarding the inclusion of capex in an EBSS is that capex tends to be less predictable than opex and 'lumpy' over time. However, this lumpiness may not always be as pronounced in distribution as it is in transmission. Opex tends to be more consistent over time because the nature of opex is that it is more constant relative to capex and is ongoing. Capex, on the other hand, is more dependent on factors such as the timing of previous expenditure on major assets (which could date back several decades), the condition of assets and associated risk, and augmentation or network growth requirements. Furthermore, DNSPs also tend to have greater discretion on the timing of capex as there is usually some flexibility regarding when projects commence.

The 'lumpiness' associated with capex tends to exacerbate the uncertainty inherent in forecasting this type of expenditure and hence increases the size of potential windfall gains or losses. The variance between actual and forecast capex may be significantly larger than that for opex, increasing regulatory uncertainty. It is noted that forecast capex at the end of the regulatory period is subject to the greatest uncertainty. The distribution network regulator for South Australia, ESCOSA, has taken the view that this uncertainty is symmetrical, so windfall gains and windfall losses are equally likely.[7] Other mechanisms in place, such as pass throughs and potentially the adjustment of forecasts when calculating carryover amounts, may also serve to mitigate the effects of this uncertainty.

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[7] ESCOSA, Electricity distribution efficiency carryover mechanism 2005–2010: Draft report, ESCOSA, Adelaide, 2006, p. 20.

Q. Would the application of an EBSS to capex yield sufficient benefits to consumers to offset the risk of windfall gains and losses?

Q. Could forecasts and/or actuals be adjusted ex post to reduce the risk of windfall gains and losses to acceptable levels?

2.4.6 Incentives to defer capex

The distribution network regulator for Victoria, the ESCV, stated in its 2006–10 revenue determination that DNSP capex savings made during that period will be excluded from its benefit-sharing scheme partly due to uncertainty as to whether variances from forecast capex are the result of genuine efficiencies or deferral of expenditure.[8] This decision was made in the context of significant underspending during 2001–05 followed by an increase in the capex forecast for the 2006–10 period.

The ESCV took the view that capex deferrals under its benefit-sharing scheme could skew the potential benefits of the scheme in favour of distribution businesses, given the prospect that customers may fund deferrals up to three times, that is:

- through financing the expenditure forecasts
- through financing rewards under the benefit-sharing scheme
- where the same (deferred) capital projects are proposed in the next reset.

In contrast, the Essential Services Commission of South Australia (ESCOSA) recently recommended the inclusion of capex in its efficiency carryover mechanism (ECM) on the grounds that it provided a neutral incentive between seeking capex efficiencies and opex efficiencies, and because ESCOSA had signalled in its 2005–10 electricity distribution price determination that it would retain capex as part of its ECM.[9] The impact of ESCOSA's inclusion of capex in its scheme will not be clear until the next determination is completed. It is noted that the operation of ESCOSA's ECM is related to its service incentive scheme since service quality improvements usually involve expenditure. ESCOSA sought to balance the incentives in the two schemes, and the design of the service incentive scheme presumed the inclusion of capex in the ECM. ESCOSA took the view that excluding capex from the ECM could affect the interactions between the two schemes and increase regulatory uncertainty.[10] In deciding to exclude capex from the operation of its efficiency mechanism, the ESCV also considered the relationship with its service incentive scheme. It noted that the

[8] ESCV, Electricity distribution price review 2006-10: October 2005 Price determination as amended in accordance with a decision of the appeal panel dated 17 February 2006, ESCV, Melbourne, 2006, p. 431–433.

[9] ESCOSA, Electricity distribution efficiency carryover mechanism 2005–2010: Final report, ESCOSA, Adelaide, 2007, p.12.

[10] ESCOSA, *Electricity distribution efficiency carryover mechanism 2005–2010: Draft report*, ESCOSA, Adelaide, 2006, p. 21–22.

exclusion of capex would likely reduce the marginal cost of service improvements, thereby increasing the incentive for DNSPs to improve their service levels.[11]

Q. Would the application of an EBSS to capex provide inappropriate incentives to delay capex?

2.4.7 Impact of the EBSS on incentives to undertake demand side responses and invest in distributed generation

NERA Economic Consulting (NERA), in its report to the MCE regarding the impacts of the NER on incentives for DNSPs to undertake demand side responses and invest in distributed generation, commented on the incentives provided by efficiency benefit sharing mechanisms.[12]

In particular, NERA discussed how an EBSS applied to opex but not capex may influence DNSPs to favour capex over opex. This in turn may impact on the incentives for the efficient valuation and utilisation of demand side responses and distributed generation, since these typically give rise predominantly to operating costs rather than capital costs. That is, an EBSS applied to opex but not capex may be to the detriment of opex related to demand side responses and distributed generation. This will depend on the relative incentives and the ability of DNSPs to maintain service quality through the trade-off between opex and capex.

The impact of an EBSS on the incentives to reduce capex and opex is, however, only one of a number of factors impacting on the incentives for DNSPs to undertake demand side responses and invest in distributed generation. Other factors such as the method for determining a DNSP's revenue requirement, tariff structures (and the availability of advanced metering infrastructure), and the form of price control also need to be considered. In addition, the NER will allow the AER to consider the introduction of a separate demand management incentive scheme to provide incentives for DNSPs to implement efficient non-network alternatives.

Thus, in considering how to provide DNSPs with appropriate incentives to implement efficient non-network alternatives, the AER will need to consider, among other things, the incentives to reduce capex and opex in the EBSS and the interaction with any demand management incentive scheme.

Q. Would the application of an EBSS to only opex materially impact DNSPs' incentives to undertake demand side responses and invest in distributed generation?

[11] ESCV, *Electricity distribution price review 2006-10: October 2005 Price determination as amended in accordance with a decision of the appeal panel dated 17 February 2006*, ESCV, Melbourne, 2006, p. 101.

[12] NERA Economic Consulting, *Distribution rules review – network incentives for demand side response and distributed generation*, April 2007.

2.4.8 Other issues regarding inclusion of capex

There is the potential that the inclusion of capex in an EBSS may result in the need for additional supporting regulatory arrangements to be implemented, in order to appropriately delineate between opex and capex where DNSPs have discretion in classifying expenditure. For example, replacing part of an asset may extend the life of that asset, and hence bring future benefits. A DNSP will face an incentive to classify expenditure as opex or capex depending on whether it prefers payoffs from the expenditure to be immediate or to accrue into the future. Because of the information asymmetry between the regulator and the business, the appropriate classification of expenditure may be difficult to enforce in the absence of additional supporting regulatory arrangements. However, a suitably designed EBSS could balance the incentives such that the DNSP is indifferent between incurring capex or opex. In determining the appropriate balance of incentives on capex and opex, the AER would need to consider the relative worth to a business of each type of expenditure. Consideration would also need to be given to the different effects on network users of DNSPs achieving savings on capex and on opex.

In forming a view on whether capex should be incorporated in the EBSS for distribution, another issue for consideration is whether a specific incentive mechanism is required for capex given the incentives inherent in the broader regulatory framework. Specifically, consideration would need to be given to whether the benefits a DNSP receives from underspends (or costs from overspends), in terms of returns on and of capital, are a sufficient incentive in their own right to induce a DNSP to achieve ongoing capex efficiencies.

Q. Are the incentives for efficient capex in the broader regulatory framework sufficient or is there also a need for an EBSS that incorporates capex?

Q. How would the exclusion of capex from the EBSS affect the overall regulatory incentives faced by DNSPs?

Q. In considering whether or not it is appropriate to include capex in the EBSS for distribution networks, what issues should the AER consider in addition to those discussed in this issues paper?

2.4.9 Treatment of distribution losses

The Allen Consulting Group and NERA, in their joint report to the MCE on network planning and connection arrangements, recommended that the AER be allowed, but not required, to develop an incentive mechanism for the management of distribution losses[13]. After the consideration of stakeholder comment on the issue,[14] the recommendation was accepted and included in the NER, allowing the EBSS for DNSPs to include efficiency gains and losses related to distribution losses.

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13 NERA Economic Consulting and The Allen Consulting Group, *Network planning and connection arrangements—national frameworks for distribution networks*, August 2007, p. 106.

14 http://www.mce.gov.au/index.cfm?event=object.showSubmissionList&objectID=B03F1041-D56C-BEEB-64A0448472FA2862.

Distribution losses can simply be defined as the difference in the amount of energy that is required to be delivered to the distribution network and the amount that is delivered to customers as measured by customer meters. Broadly, distribution losses include electrical losses (the losses associated with the passage of current through the network) and losses associated with unidentified and uncollected revenue (for example, metering errors and theft).

Under the NER, distribution loss factors are used to assign a share of distribution losses to each connected customer. This ensures that the distribution losses associated with delivering energy to a customer are paid for by the customer.

However, under current arrangements, if a DNSP takes any action to reduce distribution losses, it does not receive a share of the benefit from the loss reduction. It is the generators and retailers (and customers if cost savings are passed on by retailers) who receive the benefit (and in economic terms, a positive externality exists). Thus the incentives for a DNSP to reduce distribution losses are limited. As a result there is the potential for the level of distribution losses in the distribution network to be greater than is economically efficient.

The subject of distribution losses is a complex one and the first issue that must be addressed is whether or not distribution losses are significantly greater than the efficient level. Thus, before deciding if and how to extend the EBSS to distribution losses, the AER would require evidence of the losses currently in the distribution system and the extent to which these losses are above an efficient level.

Q. Is there any evidence available showing that the current level of distribution losses is significantly greater than the economically efficient level?

If the available evidence shows that DNSPs are not taking sufficient action to reduce distribution losses to an efficient level, the NER allows the AER to extend the EBSS to efficiency gains and losses related to distribution losses. One example of a distribution loss incentive scheme is the scheme operated by the Office of Gas and Electricity Markets (Ofgem), the gas and electricity industries regulator in Great Britain.

Under the Ofgem scheme, distributors are set a target level of distribution losses, based on historic performance, for each year of the regulatory period. Distributors are then rewarded or penalised for the difference between actual losses and the target level of losses valued by the incentive rate. In order to ensure that incentives are constant over the regulatory period, Ofgem also apply a rolling carryover mechanism analogous to the opex EBSS.

Such a scheme would ensure that DNSPs receive a benefit from any action taken to reduce distribution losses. However, it should be noted that distribution network design and operation are not the only factors affecting distribution losses.

Broadly speaking, distribution losses are a function of many parameters including the amount of electrical current running through the network, the ambient temperature, and network design and operational factors. Thus distribution losses can be affected by both consumer demand and the weather, and by network design and maintenance.

Another possible scheme for DNSPs to optimise distribution losses would be to recognise the economic value of distribution loss management investments in the regulated asset base. This approach has been adopted by the Independent Pricing and Regulatory Tribunal in NSW.[15] Any such scheme would need to be carefully designed to ensure that it provides appropriately balanced incentives when compared to other incentive schemes.

Q. If a distribution loss scheme is found necessary, would either of the Ofgem or IPART schemes be appropriate given the requirements of the NER? If not, what would be the best form of scheme?

2.4.10 Linkages with information requirements

The EBSS applying to transmission networks requires businesses to provide the following information in its revenue proposal:

- an explanation of the profile of opex sufficient to demonstrate that the opex incurred in the current regulatory period is related to operational needs as they arose and did not entail instances of cost-shifting
- a detailed description of any changes in capitalisation policies during the current regulatory control period, or that are proposed to apply in the next regulatory control period accompanied by a calculation of the impact of those changes
- the opex forecasts must include any necessary adjustments for changes in regulatory responsibilities
- the proposed basis for accounting for growth in demand in the next regulatory control period accompanied by evidence that the proposed adjustment mechanism accurately reflects the impact of changes in expected growth in demand on opex from a baseline forecast (positive and negative).

It is anticipated that to apply an EBSS to DNSPs, similar evidence will be required from businesses in their revenue proposal. Further information would be required if the AER decides to extend the operation of the EBSS to capex and/or distribution losses.

Q. Is it reasonable to require DNSPs to provide the proposed information? Is there any further information that DNSPs should provide to assist in achieving the objectives of the scheme?

[15] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09—Final Report, pp. 104–105.

3 Issues raised in this paper

The following is a consolidated list of the specific issues raised in this issues paper.

Section reference	Topic	Question raised
Post tax revenue model		
2.1.1	Basis and policy objectives	The AER seeks comment on whether other rule provisions exist that are relevant to developing the PTRM for electricity distribution. Comments are also invited on whether the provisions mentioned here may require a different approach or have different meaning in the context of distribution and transmission regulation.
2.1.2	Consistency between the PTRM for transmission and distribution regulation	The AER seeks comment on whether the PTRM developed for electricity transmission provides a suitable basis for distribution regulation. If not, what particular features or aspects of the PTRM need to be amended?
2.1.3.1	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 reset processes.
2.1.3.2	Cash-flow timing issues	Do the PTRM's current timing assumptions result in any systematic bias in favour of service providers? If so, is there merit in considering modifications to the PTRM to remove this bias, for example, in the form of present value adjustments discussed here? To what extent would these adjustments increase the administrative burden and complexity of the modelling?
2.1.3.3	Forms of control	Stakeholders are invited to comment on the benefit of incorporating indicative X factor calculations in the PTRM under common forms of price control, namely revenue caps (as per the existing PTRM), weighted average price caps, and revenue yields.
2.1.4	Linkages with information requirements	Stakeholders are invited to comment on other likely information requirements associated with the PTRM.
Roll-forward model		
2.2.1	Basis and policy objectives	The AER seeks comment on whether other rule provisions exist that are relevant to developing the RFM for electricity distribution. Comments are also invited on whether the provisions mentioned here may require a different approach or have different meaning in the context of distribution and transmission regulation.
2.2.2	Consistency between the RFM for transmission and distribution regulation	Stakeholders are invited to comment on whether there are any impediments to using the AER's transmission RFM as a basis for the distribution model.

Section reference	Topic	Question raised
2.2.3	Distribution specific issues	The AER invites comments on whether the adoption of existing models is appropriate and whether there are specific issues regarding these models, and current jurisdictional revenue determinations, that the AER needs to consider in performing its first round of roll-forward calculations in each jurisdiction.
Cost allocation guidelines		
2.3.3	Linkages to other guidelines	Written comments from interested parties are sought on the following: ▪ Given the similarity between the respective NER provisions for transmission and distribution, to what extent should the AER adopt a similar approach to cost allocation between distribution and transmission businesses? ▪ Are the proposed general principles discussed above for the provision of information for cost allocation in the distribution sector appropriate? ▪ Should any other general principles and or requirements be reflected in the distribution cost allocation guidelines?
Efficiency benefit sharing scheme		
2.4.2	Similarities with the approach to transmission networks	Is it reasonable to apply to DNSPs an EBSS with the same general approach as the transmission EBSS? Are there any significant differences between transmission and distribution businesses that would require a different general approach?
2.4.5	Nature of capex	Would the application of an EBSS to capex yield sufficient benefits to consumers to offset the risk of windfall gains and losses? Could forecasts and/or actuals be adjusted ex post to reduce the risk of windfall gains and losses to acceptable levels?
2.4.6	Incentives to defer capex	Would the application of an EBSS to capex provide inappropriate incentives to delay capex?
2.4.7	Impact of EBSS for incentives for demand side response and distributed generation	Would the application of an EBSS to only opex materially impact DNSPs' incentives to undertake demand side responses and invest in distributed generation?
2.4.8	Other issues regarding inclusion of capex	Are the incentives for efficient capex in the broader regulatory framework sufficient or is there also a need for an EBSS that incorporates capex? How would the exclusion of capex from the EBSS affect the overall regulatory incentives faced by DNSPs? In considering whether or not it is appropriate to include capex in the EBSS for distribution networks, what issues should the AER consider in addition to those discussed in this issues paper?

Section reference	Topic	Question raised
2.4.9	Treatment of distribution losses	Is there any evidence available showing that the current level of distribution losses is significantly greater than the economically efficient level? If a distribution loss scheme is found necessary, would either of the Ofgem or IPART schemes be appropriate given the requirements of the NER? If not, what would be the best form of scheme?
2.4.10	Linkages with information requirements	Is it reasonable to require DNSPs to provide the proposed information? Is there any further information that DNSPs should provide to assist in achieving the objectives of the scheme?