AEMC

RULE CHANGE

Australian Energy Market Commission

DISCUSSION PAPER

National Electricity Amendment (Inter-regional Transmission Charging) Rule 2011

Rule Proponent

Ministerial Council on Energy

Commissioners

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25 August 2011

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. The AEMC has two principal functions. We make and amend the national electricity and gas rules, and we conduct independent reviews of the energy markets for the MCE.

Summary

The Ministerial Council on Energy (MCE) has proposed a Rule change request in respect of inter-regional transmission charging. In response to this request, the Australian Energy Market Commission (AEMC or Commission) is considering introducing a uniform national inter-regional transmission charging solution. This has the potential to improve the cost-reflectivity of transmission charges and the allocation of costs across regions. Most consumers in the National Electricity Market (NEM) do not currently contribute to the costs of transmission assets in other regions that support electricity flows to their region.

The Commission is seeking comment on several options to develop a uniform national inter-regional transmission charging regime. The scope does not extend into changing the approach to the current intra-regional transmission charging arrangements. Where issues are identified in relation to the intra-regional transmission charging arrangements, it would be more appropriate that they be addressed through alternative processes such as the longer term Transmission Frameworks Review.

The development of a uniform national inter-regional transmission charging regime must be based on an appropriate set of objectives. This, in turn, would promote efficient outcomes in the NEM in the long term interest of consumers. This Paper develops an assessment framework to evaluate options for inter-regional transmission charging that would ensure that any changes to the National Electricity Rules (Rules) are consistent with promoting the National Electricity Objective (NEO).

This Discussion Paper is intended to test the various options with stakeholders to assist the Commission in determining the overall objectives for developing a uniform national inter-regional transmission charging regime, consistent with the NEO. The Discussion Paper provides a list of questions to assist stakeholders in their submissions; however, the Commission welcomes any additional relevant comments from stakeholders by 23 September 2011.

Contents

1 Introduction

1.1 The Rule change request

On 15 February 2010, the Ministerial Council on Energy (MCE) (Proponent) submitted a Rule change request to the Australian Energy Market Commission (AEMC or Commission) seeking to implement an inter-regional transmission charging mechanism (Rule change request). The Rule change request proposed that new inter-regional transmission charging arrangements be introduced such that Transmission Network Service Providers (TNSPs) in each region would levy a new charge - a Load Export Charge (LEC) - on transmission businesses in adjoining regions.

1.2 Draft Rule determination

On 2 December 2010, the Commission published a draft Rule determination and draft Rule. The Commission proposed to introduce an inter-regional transmission charging mechanism in the form of a LEC. Most consumers in the NEM do not currently contribute to the costs of transmission assets in other regions that support electricity flows to their region. The Commission considered that the LEC would improve the cost-reflectivity of transmission charging such that consumers that benefit from inter-regional flows contribute to the costs of the transmission assets to provide those flows.

Submissions in response to the draft Rule determination argued against the proposed design of the LEC. Issues raised include the fact that the redistribution of costs may not reflect the actual usage of interconnection, and the inconsistency between the transmission charging methodologies provided. After considering submissions and modelling undertaken, the Commission formed the view that the inconsistency in the way the LEC would be calculated in each region would undermine the credibility of the reforms.

In response, in April 2011 the Commission extended the period for making its determination on the Rule change request to consider the issues further. At this time the Commission, amongst other things:

- noted stakeholder concerns regarding consistency in the way a LEC was originally to be applied to recover inter-regional transmission charges; and

- committed to a uniform national inter-regional transmission charging regime.

1.3 Scope of the Discussion Paper

In light of the submissions on the draft Rule determination, this Discussion Paper reconsiders the objectives of inter-regional transmission charging and identifies several options that might achieve those objectives. These options include:

- Option 1: Modified Load Export Charge;

- Option 2: Cost Sharing; and
- Option 3: NEM-wide Cost Reflective Network Pricing (CRNP).

The Commission seeks stakeholder views on:

- the objectives of inter-regional transmission charging, as discussed in Chapter 3; and
- which of the proposed options, including methodologies, for inter-regional transmission charging in the Discussion Paper best achieves the objectives.

The Commission also welcomes submissions on whether there are any other options that should be considered.

At this stage, inter-regional transmission charging appears likely to contribute to the NEO. However, without further analysis, detailed modelling and stakeholder feedback, the Commission considers that it would be premature to provide a more definitive view that any of the options (including other options suggested by stakeholders) would be the best way of implementing inter-regional transmission charging. In particular, there may be challenges in the practical implementation of these options. If, following further analysis, the Commission expects that the costs of these options would outweigh the benefits then the Commission's overall approach to inter-regional transmission charging may change.

1.4 Modelling

The Commission considers that modelling would be required to ensure the implementation of any inter-regional transmission charging option would lead to an appropriate allocation of costs, and provide a better understanding of the distributional impact. At this stage of the process, it is premature to model the potential impact for each of the different inter-regional transmission charging options, given the various possible approaches in applying these options. It is envisaged that following consideration of stakeholder submissions on the Discussion Paper, an appropriate set of specifications will be developed for a uniform national inter-regional transmission charging regime. From this, modelling may be possible and presented in the second draft Rule determination.

1.5 Timeframe and next steps

The following are the planned project milestones for the Rule making process:

- Close of submissions on Discussion Paper: Friday, 23 September 2011;
- Publication of second draft Rule determination: Thursday, 17 November 2011 (this date is contingent on the completion of the modelling discussed above);
- Close of submissions on second draft Rule determination: Friday, 6 January 2012;

- Publication of final Rule determination: Thursday, 16 February 2012.

It is envisaged, if a Rule is made, that the inter-regional transmission charging mechanism would apply from 1 July 2013.

1.6 Process for making a submission

The Commission invites submissions on this Discussion Paper by 23 September 2011. Submissions should quote project number “ERC0106” and may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission

PO Box A2449

SYDNEY SOUTH NSW 1235

1.7 Structure of this Discussion Paper

The remainder of this Discussion Paper is structured as follows:

- section 2 provides a background to the reason for the review of the inter-regional transmission charging options;
- section 3 considers the assessment framework for assessing the inter-regional transmission charging options;
- section 4 highlights key design issues in developing an inter-regional transmission charging methodology;
- section 5 discusses the specific design issues related to the Modified Load Export Charge option;
- section 6 discusses the specific design issues related to the Cost Sharing option; and
- section 7 discusses the specific design issues related to the NEM-wide CRNP option.

2 Background

The development of provisions for inter-regional transmission charging were first considered by the Commission as a part of the Review of Electricity Transmission Revenue and Pricing Rules, which was initiated in 2005. Potential solutions were considered further in the National Transmission Planner (NTP) Review and one of the recommendations to the MCE from the Review was that the current lack of a systematic inter-regional transmission charging mechanism could impede the development of a more efficient national transmission network.[1] In response, the MCE requested that the Commission consider the need to improve the existing inter-regional transmission pricing arrangements as a part of the Climate Change Review.[2]

In the Final Report on the Climate Change Review, the Commission recommended the introduction of an obligation on transmission businesses to levy a "load export charge" on the transmission business in each adjoining region.[3] This charge would reflect the costs of providing transmission capacity to transport electricity to the adjoining regions. In its policy response to the Climate Change Review, the MCE supported, in principle, the introduction of the load export charge.[4] This formed the basis of the Rule change request currently being considered.

The history of the progress of the Rule change request is available on the AEMC website.[5]

2.1 Transmission Frameworks Review

On 20 April 2010, the MCE directed the Commission to conduct a review of the arrangements for the provision and utilisation of electricity transmission services in the National Electricity Market (NEM), with a view to ensuring that the incentives for generation and network investment and operating decisions are effectively aligned to deliver efficient overall outcomes (Transmission Frameworks Review). The Commission is to review the role of transmission in providing services to the competitive sectors of the NEM, through considering the following key areas:

- transmission investment;
- network operation;

1 AEMC 2008, National Transmission Planning Arrangements, Final Report to MCE, 30 June 2008, pp. 68-72.

2 The Hon Martin Ferguson AM MP, Chair MCE, Letter to Dr Tamblyn, Chairman AEMC, 5 November 2008. See www.mce.gov.au.

3 AEMC 2009, Review of Energy Market Frameworks in Light of Climate Change Policies: Final Report, September 2009, pp. 42-53.

4 MCE 2009, Response to the AEMC's Final Report on the Review of Energy Market Frameworks in Light of Climate Change Policies, December 2009, pp. 7-8. See www.mce.gov.au.

5 www.aemc.gov.au

- network charging, access and connection; and
- management of network congestion.

Some submissions on the draft Rule determination suggested that the Rule change request be deferred and that an inter-regional transmission charging regime be considered holistically as part of the Transmission Frameworks Review. However, the Commission has stated that it will proceed to develop a uniform national inter-regional transmission charging regime and methodology.

The development of this regime and methodology will have regard to the AEMC's separate longer term Transmission Frameworks Review, but will not be merged with that review. The Commission would not implement an option that was inconsistent with the emerging conclusions of the Transmission Frameworks Review, but the Commission will consider options that would be an interim measure if the emerging conclusions of the Transmission Frameworks Review suggests more radical changes to transmission charging structures.

The Commission considers that if it determines the benefits of inter-regional transmission charging outweigh the costs it would be better to proceed with a transitional inter-regional transmission charging solution sooner, as opposed to waiting until the Transmission Frameworks Review has been concluded and any Rule change arising out of it is considered. Importantly, subject to modelling, this approach has the potential to improve the cost-reflectivity of charges and the allocation of costs across regions compared to the current arrangements (especially in the event of changes in transmission flows).

2.2 Reason for considering other inter-regional transmission charging options

In submissions on the draft Rule determination, stakeholders raised a number of concerns with the LEC that had been proposed; in particular, regarding the volatility in charges, a likely redistribution of costs arising from the application of the proposed methodology which would be inconsistent with the benefits of interconnection.[6] Submissions also noted the lack of consistency in transmission pricing methodologies across the NEM, and argued that this could influence the effectiveness of inter-regional charging. These submissions highlighted that there are a number of differences amongst existing transmission pricing methodologies that could impact on the efficiency of any inter-regional transmission charging scheme.

The Commission considered that a key problem raised in submissions on the draft Rule determination was the inconsistencies between the current intra-regional transmission methodologies. In particular, the inconsistency in the calculation of the LEC could undermine the credibility of the reforms. Therefore, the Commission decided that there was a need for consistency in the application of an inter-regional

6 For further details on the inconsistencies, see Chapter 4 of this Discussion Paper.

transmission charge on a NEM-wide basis, and decided to develop a uniform national inter-regional transmission charging regime and methodology.

Given the potential practical difficulties in implementing a uniform national methodology through a LEC, the Commission has reviewed the assessment framework required to achieve this objective. The framework will form the basis to consider other inter-regional transmission charging options which might achieve a consistent methodology.[7] These options were previously reviewed in the NTP Review and the Review of Energy Market Frameworks in Light of Climate Change Policies (Climate Change Review).[8]

7 The assessment framework is discussed in Chapter 3 of this Discussion Paper.

8 The options are discussed in detail in chapters 5 to 7 of this Discussion Paper.

3 Assessment Framework for Developing Options on Inter-regional Transmission Pricing

This chapter considers the assessment framework to be used by the Commission in assessing the options for development of an inter-regional transmission charging methodology. The economic concepts behind the development of this assessment framework are included in Appendix A.

In assessing any change to market and regulatory arrangements, the AEMC is required to have regard to the NEO, which is to:

> "promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
>
> (a) price, quality, safety, reliability, and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

The development of an inter-regional transmission charging regime would be particularly relevant for promoting efficient investment in, and use of, electricity services.

3.1 Criteria for assessing inter-regional transmission pricing options

Establishing an efficient charging methodology for inter-regional transmission assets would require a number of complex considerations to be taken into account and trade-offs to be made. This is due to the unique characteristics of transmission, which include economies of scale (at both the technical and firm specific level) and network externalities created by loop flows. These are discussed in detail in Appendix A, but in summary have the following important implications for developing an efficient charge:

- Static versus dynamic efficiency - consideration would need to be given to whether the charge should be oriented to support static (allocative) or dynamic efficiency objectives. The extent to which an inter-regional transmission charge would be predominantly focussed on one or the other will depend on whether the efficiency of current network utilisation or future investment is considered more important as a policy objective for the charge. This decision would need to take into account the degree to which a forward looking charge would drive efficient behaviour, as well as what other regulatory mechanisms are available to achieve this objectives. For instance, the short run marginal cost (SRMC) signals provided in the wholesale market and the Regulatory Investment Test for Transmission (RIT-T) are also intended to provide forward looking signals for the efficient future development of the network.

- Identification of causers or beneficiaries - the efficiency benefits associated with allocating cost to cause would significantly depend on the degree to which specific causers or beneficiaries of transmission can be identified. This may be difficult for transmission elements that form an integrated part of the broader shared network, in particular those supporting inter-regional flows. This is because the utilisation of a particular transmission element (due to loop flows) would in part depend on the actions of network users elsewhere in the network. Further, some of the key benefits of inter-regional transmission assets, such as reserve sharing, reduced congestion and enhanced competition, tend to fall to network users more broadly. Consequently, to the extent that specific causers or beneficiaries of transmission are difficult to identify this implies that charges that vary significantly from one location to another may add little in terms of efficiency.

- Implementation and administration costs - ensuring charges are transparent, administratively simple and stable are further important considerations in developing an inter-regional transmission charge. This is because network users operate in competitive markets with small margins. Charges that are stable, transparent and predictable would support business and investment decisions and minimise the impacts of regulatory uncertainty.

This suggests a criteria for assessment as follows:

1. Achieving more cost-reflective price signals - this requires consideration of how the methodology:

    (a) recovers the costs of the existing network;

    (b) provides a signal for future investment; and

    (c) reflects a "causer or beneficiary pays" approach; and

2. Procedural and implementation issues - this includes:

    (a) administrative efficiency;

    (b) transparency; and

    (c) stability and regulatory certainty, including cost impacts.

The charging methodology for recovering the costs of inter-regional transmission assets should consider all of these issues in a balanced manner. The Commission has set out a number of inter-regional charging options in this consultation paper which reflect a different priority weighting of these issues. The extent to which each option emphasises a particular aspect of the assessment framework would be highlighted to help identify for participants the efficiency trade-offs implicit in each option.

3.2 Questions

Question 1	**Is the assessment criteria identified in this Discussion Paper appropriate for developing a uniform national inter-regional transmission charging methodology?**
Question 2	**Is the criteria for assessment proposed appropriate for assessing the various options for a uniform national inter-regional transmission charging regime?**

4 Key Design Features of Transmission Charging Methodologies

A key objective of introducing a uniform national inter-regional transmission charging methodology is stability and certainty, which includes ensuring that it is as consistent as possible with existing regimes. This chapter examines areas of potential differences in the current intra-regional transmission charging arrangements.

Although it is not within the scope of this Rule making process to amend the existing arrangements for intra-regional transmission pricing, it is still important to identify these design features as these could have an impact on the design of a uniform national inter-regional transmission charging regime. Further, the Commission considers that unless the differences discussed below are applied consistently, then the various inter-regional transmission charging options would be very challenging to implement.

A background on the current intra-regional transmission charging arrangements is included in Appendix B.

4.1 Cost Reflective Network Pricing

4.1.1 Background

The majority of prescribed Transmission Use of System (TUoS) services are recovered in the form of either a locational or non-locational charge. The way the Annual Service Revenue Requirement (ASRR) is split between the locational and non-locational components of prescribed TUoS services can be either on a 50:50 basis (standard Cost Reflective Network Pricing (CRNP)), or based on a reasonable estimate of future network utilisation and the likely need for future transmission investment (modified CRNP), which has the objective of providing more efficient locational signals.[9]

4.1.2 Issues

The difference between the standard CRNP methodology and modified version is that the latter attempts to better reflect the LRMC of the network (contributing to dynamic efficiency) by providing a discount to users for more lightly loaded lines. That is, potential customers would be more incentivised to move to areas that minimise transmission costs where the charge reflects the forward looking costs of their decisions. As a result, existing customers would not be charged more in the event of low utilisation of radial lines and potential customers would be provided with a financial incentive to locate where the utilisation rate is low (and there is excess capacity).[10]

9 NER clause 6A.23.3(d)(1)-(2).

10 Network Advisory Services, AEMC Review of Transmission Pricing, June 2009, p. 36.

In effect, the modified CRNP appears to provide a better method than the standard CRNP for locational signalling as more emphasis is placed on the level of utilisation of the transmission network. However, the modified CRNP would be more complicated to apply than the standard CRNP as a certain level of subjectivity would be required to establish line ratings. These line ratings would be used by the TNSP as part of the process to determine the level of utilisation on a line. Given the trade-off required between locational signalling and ease of implementation, the choice of options may depend on the level of priority given to dynamic efficiency.

In practice, ElectraNet (South Australia) and Transend (Tasmania) use the modified CRNP. The other TNSPs use the standard CRNP (i.e. Australian Energy Market Operator (AEMO) (Victoria), Powerlink (Queensland) and TransGrid (New South Wales)). However, Grid Australia considers that the choice of standard CRNP or modified version would not materially impact on the calculation of a LEC.[11]

Below is a summary of the advantages and disadvantages of the standard CRNP and modified CRNP methodologies.

Table 4.1 Advantages and Disadvantages of the CRNP methodologies

<table>
<tr><th>CRNP Methodology</th><th>Advantages</th><th>Disadvantages</th></tr>
<tr><td rowspan="2">Standard CRNP</td><td rowspan="2">Simpler to use</td><td>Provides less efficient forward looking signals relative to modified CRNP</td></tr>
<tr><td>Based on an arbitrary 50:50 split of locational and non-locational costs</td></tr>
<tr><td rowspan="2">Modified CRNP</td><td>Provides a better method for locational signalling - more emphasis placed on low utilised network</td><td rowspan="2">More complicated to apply - a certain level of subjectivity would be required to establish line ratings</td></tr>
<tr><td>Not based on an arbitrary 50:50 split of locational and non-locational costs</td></tr>
</table>

11 Grid Australia, Submission on the draft Rule determination, 11 March 2011, p. 3.

4.2 Operating Conditions for Cost Allocation

4.2.1 Background

As part of the standard CRNP (and modified version), costs are allocated on the basis of operating conditions resulting in most stress on the transmission network and where network investment may be contemplated.[12] In practice, there are currently two methods being used to determine this:

- the 10-day system peak method; and
- the 365-day element peak method.

The 10-day system peak method is currently only used by AEMO. It is based on average maximum demand during the previous 12 months, takes the top ten system half-hour intervals (which must occur on different days), measures element loadings for each load point on each of those ten half-hour intervals, and averages the results. As a result, this method apportions the costs to loads as they contribute to system peak.

In contrast, the 365-day element peak method is used by the other TNSPs. It measures the peak loading of all elements supplying a load point over 365 days and determines the contribution of each load point to the total flows on each element at the time of peak load on that element. Costs are then apportioned to load as they contribute to individual elements' peaks.

The Commission is not aware of any other current method in Australia for determining the operating conditions for cost allocation, and has therefore only focussed on the methods currently used in practice above. However, the Commission welcomes stakeholders comments on whether there would be any other methods for determining the operating conditions for cost allocation that have not been discussed. For example, it may be possible to use a system peak method but apply it over 365 days instead of ten days.

4.2.2 Issues

In its submission on the draft Rule determination, AEMO suggests that the two methodologies above "yield different results at regions' borders and therefore justifying alignment of approach for all regions", and indicated a preference for the 10-day system peak method.[13] Some reasons for AEMO's preference are that the 10-day system peak method better reflects the need to augment the shared transmission network at system peak rather than at element peak, incentivises large customers to voluntarily reduce their loads at system peak load periods, and promotes demand side participation.

12 NER Clause 6A.23.4(e).

13 AEMO, Submission on the draft Rule determination, 25 February 2011, pp. 3, 8.

The other TNSPs, on the other hand, preferred the 365-day element peak method.[14] A reason provided by Grid Australia for using the 365-day element peak method is because the method takes into account a broader range of operating conditions for network investment compared to the 10-day system peak method.[15] Grid Australia also considered that the 10-day system peak method gives more discretion for the TNSP to choose the peak days and the inadvertent ability to pick winners and losers.[16] For instance, the generation pattern would only be applicable to the ten half-hours chosen by the TNSP which may not be representative of system peak generally (for example, if a major generator tripped in one of the ten half-hours).

Below is a summary of the advantages and disadvantages of the 10-day system peak and 365-day element peak methodologies. The Commission notes that these were based on comments from AEMO and Grid Australia's submissions on the draft Rule determination.

Table 4.2 Advantages and Disadvantages of 10-day system peak

Advantages	Disadvantages
Better reflects the need to augment at system peak than at times of element peak	May not accurately account for any connection points that have low usage on the ten days of system peak
Promotes avoided TUoS effectiveness where the embedded generator receives avoided TUoS payments at times where system would likely be at its peak loading	Discretion within the AER pricing guidelines for a TNSP to choose the ten days of system peak creates a degree of subjectivity
Encourages heavy users to voluntarily reduce loads at times of system peak where they can predict these	An implementation issue is that this method is only used by AEMO

Table 4.3 Advantages and Disadvantages of 365-day element peak

Advantages	Disadvantages
Removes ability to inadvertently pick winners and losers in the calculation of locational prices	Load point is charged at maximum TUoS price irrespective of when the system peak occurred
Identifies times when major loads located in proximity to major generators would be drawing on the broader network due to local generator outages or bidding behaviours	Less incentive for large customers drawing significant load from the transmission system to voluntarily reduce their loads at system peak load periods
Takes into account a broader range of operating conditions for network investment	Less incentive to locate closer to generation sources

14 Grid Australia, Supplementary submission on the draft Rule determination, 11 March 2011, p. 11.

15 Grid Australia, Supplementary submission on the draft Rule determination, 11 March 2011, p. 4.

16 Grid Australia, Supplementary submission on the draft Rule determination, 11 March 2011, p. 4.

Advantages	Disadvantages
	Embedded generators may have less incentive to generate at, and therefore reduce, system peak
	Can result in a charge to loads that make no contribution to system peak

4.3 Treatment of Postage Stamp Components

4.3.1 Background

Prescribed common transmission service charges are defined in the NER as providing equivalent benefits to all transmission customers on the network without any differentiation based on their location. For example, this may include TNSPs' control buildings, protection systems, communication systems, and earth mats.[17] The prescribed common transmission service charge is recovered from transmission customers on a postage stamp basis.[18]

Prescribed non-locational TUoS service and prescribed common transmission service charges must be recovered on a postage-stamp basis and are charged to customers based upon actual demand or energy consumed. Such charges do not signal the marginal cost of providing the transmission service and therefore do not have an economic signalling function. Instead, their purpose is to ensure full cost recovery for TNSPs. Hence, such charges are designed to be applied in a manner which least distorts the participant's consumption and location decisions.

In the draft Rule determination, the prescribed common transmission service charge and prescribed non-locational TUoS service charge components (postage stamp components) had been included in the LEC. This would reflect the similar treatment for these components in the current intra-regional transmission charging and would therefore be an incremental change to the existing arrangements.

4.3.2 Issues

From submissions on the draft Rule determination, stakeholders have argued that the inclusion of the postage stamp components in the LEC would distort its locational signal. This is due to the potential differences between TNSPs in their composition of the postage stamp components, such as the type of assets included and state-based taxes. For example, approximately 20 per cent of the Victorian easement land tax ($93 million) would be transferred to Tasmania and South Australia, which some stakeholders see as less cost reflective and inconsistent with the NEO.

17 Clause 2.4(4) of AER, Pricing methodology guidelines, Final Decision, October 2007.

18 NER Clause 6A.23.4(d) and (j).

In addition, the inclusion of the postage stamp components into the LEC would lead to significant volatility from year to year, since it would be calculated (as postage stamp components in intra-regional transmission charges are) on the basis of energy flows which are not always consistent from year to year. Stakeholders considered that this could have a material detrimental impact on customers, especially large customers who off-take supply directly from the transmission network. For this reason, a number of submissions have proposed that the postage stamp components be omitted from the LEC.

The Commission notes that including prescribed non-locational TUoS service and prescribed common transmission service charges into the LEC would mean that a large proportion of the LEC would comprise of charges which would not have an economic signal and would be charged on a usage basis. This could lead to questions of the economic efficiency rationale for their inclusion and could result in the LEC being volatile. On the other hand, such charges would need to be recovered to ensure TNSPs recover their costs. If non-locational prescribed TUoS service charges are excluded from inter-regional transmission charges, there would then be a question as to why inter-regional transmission customers should be treated differently from intra-regional transmission customers which respect to these costs.

Below is a summary of the advantages and disadvantages of including the postage stamp components.

Table 4.4 Advantages and Disadvantages of including Postage Stamp Components

Advantages	Disadvantages
Consistent with the current intra-regional transmission pricing arrangements which includes all these components	May distort the locational signal as it does not have locational signalling function
Implementing such a charge would only be an incremental change as it would be consistent with the current intra-regional transmission pricing arrangements	Not applied consistently across regions in terms of the methodology applied and the components included e.g. Victorian land easement tax
Reflects the non-locational costs associated with providing transmission services	Contributes to high price volatility as it would be based on actual flows between regions

4.4 Other differences between TNSPs' methodologies

The Commission has identified above what it considers to be the key material differences in application of TNSPs' methodologies as they apply to inter-regional transmission charging. However, there may be other material differences that have not been addressed and the Commission welcomes stakeholder comments on any additional differences that have not been identified in this Discussion Paper.

Further, there are other differences which may or may not be material with respect to inter-regional transmission charging which the Commission would appreciate stakeholder comments on. These include:

- measure of demand used to set prices; and
- valuation of assets.

4.4.1 Measure of demand used to set prices

Under the old pricing rule[19], the prescribed non-locational TUoS service and prescribed common transmission service prices and charges were calculated both on historical energy and contract capacity basis. A network customer at a connection point would be charged for the lesser amount of the two types of charging options. This was done to provide for equity for some customers and has not been changed in the NER.[20]

An issue is that different TNSPs may use different measures of demand for pricing and charging the postage stamp components. For instance, TransGrid uses the actual monthly maximum demand, whereas the other TNSPs use a contract agreed maximum demand. Differences in approach could result in customers being charged on different bases for the same type of service.

4.4.2 Valuation of assets

The valuation of transmission system assets are based on the optimised replacement cost (ORC). The ORC for the assets are used to determine the ratio between the costs of the transmission system assets directly attributable to the provision of that category of prescribed transmission services to the total costs of all the TNSP's transmission system assets directly attributable to the provision of the prescribed transmission services. This is the attributable cost share described under clause 6A.22.3 of the NER.

Generally, any differences between TNSPs' methodologies for valuing these assets are not important as the ratio is used (i.e. the attributable cost share) and therefore the effect of the asset valuation method is not an issue. However, if the assets are considered across the entire NEM as opposed to on a region-by-region basis, then differences between one TNSP's methodology to another may become a critical issue. That is, if each TNSP applies a different methodology for calculating the ORC of their own assets, then the attributable cost share of the pooled costs would be based on different methods. This would lead to an inconsistency in the methodology for valuing assets.

4.5 Questions

Question 3 If a uniform national CRNP methodology were chosen,

19 NER version 9.

20 AER, Pricing methodology guidelines, Final Decision, October 2007, p.7.

	should the components of the methodology be specified in the NER or else left to the TNSPs to determine?
Question 4	**If a uniform national CRNP methodology were chosen, which components need to be determined as part of a uniform national CRNP methodology?**
Question 5	**If an inter-regional transmission methodology was chosen which required a consistent form of CRNP methodology, would the standard CRNP or modified methodology be the most appropriate to use for inter-regional transmission charging?**
Question 6	**If an inter-regional transmission methodology was chosen which required a consistent form of methodology for determining the operating conditions for cost allocation, would the 10-day system peak methodology or 365-day element peak methodology be the most appropriate to use for inter-regional transmission charging? Or, is there another more preferable alternative?**
Question 7	**To the extent that there are any differences between TNSPs' measure of demand for setting and calculating prescribed locational and non-locational TUoS services, and prescribed common transmission service prices and charges, is it necessary to have a single measure of demand in order to achieve a uniform inter-regional transmission charging regime?**
Question 8	**To the extent that there are any differences between TNSPs' asset valuation methodologies, is it necessary to have a single methodology to achieve a uniform inter-regional transmission charging regime?**

5 Option 1: Modified Load Export Charge

A form of LEC was proposed in the draft Rule determination in December 2010 (original LEC). Submissions in response to the draft Rule determination stated, among other things, that there would be problems applying the original LEC due to the lack of consistency in the intra-regional TUoS charging methodologies amongst regions of the NEM. A number of submissions also indicated that charges for the postage stamped components should be excluded from the original LEC. This chapter considers the original LEC and offers a modified form of LEC (modified LEC) as a solution to the concerns raised in submissions.

5.1 Description of the Load Export Charge previously proposed in the draft Rule

Under this approach, a transmission business in each region was to levy a LEC on TNSPs in adjoining regions. The charge would be calculated as if the relevant interconnection with the importing network was a load on the boundary of the exporting region. It would reflect the costs of the assets in the exporting region which contribute to the transfer capability to export flows to the importing region.

The original LEC as proposed in the draft Rule was to comprise the prescribed locational TUoS service charge, the prescribed non-locational TUoS service charge and the prescribed common transmission service charge. In most respects the inter-regional load point would be treated in the same way as all of the exporting transmission business's other load points. The CRNP would be applied using the same methodologies and TNSPs would be required to submit pricing methodologies as part of the transmission determination process for every revenue reset to the AER. This option was to offer a means of implementing inter-regional transmission charging that would be incremental to existing transmission charging arrangements.

The draft Rule determination prescribed how the charges levied on an importing transmission business would be recovered from that business's customers. The prescribed locational TUoS service component of the original LEC would be added to the prescribed locational TUoS service component of the intra-regional transmission charge, and the prescribed non-locational TUoS service component of the original LEC would be added to the prescribed non-locational TUoS service component of the intra-regional transmission charge.

The cost impacts of the original LEC were modelled in a way that identified disaggregated prescribed locational TUoS, non-locational TUoS and common transmission services charges. These were based on each TNSPs' own methodologies. Based on the inclusion of prescribed non-locational TUoS service charges, it was found that customers in NSW and Tasmania would be net payers of the original LEC, though in each case the increase in a small customer's bill in those regions would be less than 1%. However, the cost increases for larger customers have not been assessed. Some submissions suggested that this could be considerable if the prescribed non-locational TUoS service component is included in the charge. Nevertheless, those costs may be justified if the intention of the charge is to encourage more efficient locational decisions with respect to ensuring efficient investment in inter-regional transmission over time. Based on internal modelling these figures would change if the prescribed non-locational TUoS service component was removed, such that Victorian customers would become the only net payers in the NEM, with the total net impact in Victoria of approximately 5% of Aggregate Annual Revenue Requirement (AARR). The actual cost impacts would depend on the exact composition of the inter-regional charging methodology adopted.

5.2 Modified Load Export Charge

As an alternative to the original LEC, this section sets out how the modified LEC described above might work. Under this modified LEC, the calculation of transmission charges for intra-regional load points would be kept separate from the calculation for inter-regional load points, allowing current methodologies to be retained for the intra-regional calculation. The TNSP would undertake one application of its CRNP methodology for intra-regional load points according to current arrangements in which no inter-regional load points would be included. The TNSP would then also be required to apply an adapted form of CRNP methodology (based on a uniform national methodology) including an additional load point (or points, depending on how many adjoining regions there were) representing the relevant interconnection with the importing network or networks. This second application of the CRNP methodology would only have the function of producing a charge for the importing regions. To the extent the charges for intra-regional load points differed from those determined in the first application of the CRNP methodology, these would be ignored.

As with the original LEC, the importing region TNSP would recover the inter-regional charge from its customers. The exporting region TNSP would rebate the inter-regional charge it recovers to its customers. In both cases, the charges should be able to be applied so that customers only see one aggregated charge comprising of both intra- and inter-regional elements. The specific approach to importing region recovery and exporting region rebate is not included here.

Applying a modified LEC - which would recover inter-regional transmission charges on a bilateral basis - has a shortcoming in that inter-regional charges could only be levied on TNSPs in adjoining regions. For example, if there are regions A, B, and C where region B adjoins regions A and C but regions A and C do not adjoin, region A levies a charge on region B and region B levies a charge on region C but region A does not levy a charge on region C. While consumers in region C may benefit from the transfer capability in region A to export flows, they do not contribute to the costs of those assets. For an option which does provide the possibility of charging in non-adjoining regions, see chapter 7 below.

In addition to the specific considerations applicable to the design of the modified LEC discussed below, if this option were chosen decisions on the following would need to be made to determine how the methodology should be applied:

- the choice of CRNP methodology;

- the choice of methodology for determining the operating condition for cost allocation;
- the choice to include or exclude postage stamp components; and
- the choice of methodology for asset valuation.

5.3 Identifying the Assets Included

As with the form of the original LEC, all assets would as a matter of course be included. The CRNP methodology would determine which load points contribute to the recovery of costs for each network element.

5.4 Determining and Allocating the Costs

Under the original LEC, the AER would amend its pricing methodology guidelines to require consistency in the TNSPs' pricing methodologies. This consistency was to be achieved by AEMO adjusting its methodology to reflect the "element peak" method used elsewhere in the NEM. This requirement for pricing methodology consistency for both intra-regional and inter-regional charges was a source of stakeholder dissatisfaction following the draft Rule determination.

The key difference between the original LEC and the modified LEC is that a uniform national CRNP methodology would be prescribed to determine the transmission charges for inter-regional load points only. This would adopt the same basic form as the charging methodologies applied to determine intra-regional transmission charges. However, as discussed above, submissions on the draft Rule determination have identified differences in the transmission charging methodologies applied in each region of the NEM. As a result, a decision would need to be made as to which of the parameters would be applied as part of the uniform national CRNP methodology. Some of these differences have been considered in chapter 4: see the discussions of the system peak method versus the element method, and the standard CRNP versus the modified CRNP, for example.

5.5 Preliminary observations

Compared to the current provisions in the NER, the modified LEC would better reflect the interconnected nature of the NEM. By requiring customers who benefit from imports of energy to contribute to the cost of transmitting that energy, transmission prices would be more cost-reflective. The discussion in Chapter 3 noted that an efficient cost reflective transmission charge can be defined in a number of different ways, depending on whether the focus of the charge was to signal future investment requirements, or minimise distortions to current use of the network. The modified LEC attempts to achieve a balance in the same way as the existing intra-regional pricing methodology. Thus, approximately half of the total costs of assets contributing to inter-regional flows would be recovered within regions on a postage stamp basis (the charge would be the same regardless of location or use) and the other half would be allocated on the basis of proportionate use, in order to attribute costs to those considered to cause the need for investment in inter-regional transmission. In light of the criteria for assessment above such a charge may be considered to improve existing efficiency if:

- the CRNP methodology can appropriately identify the causers or beneficiaries of inter-regional transmission over time;
- the CRNP methodology would be an effective proxy for the long run marginal cost (LRMC) of augmenting the network;
- transmission users would be able to respond to dynamic investment signals provided by CRNP type approaches;
- the charge does not lead to over-signalling with respect to the SRMC of transmission (congestion and losses); and
- transaction costs would be minimised under this approach.

Some important points to note:

- the modified LEC allocates costs on the basis of the direction of energy flows, which attempts to reflect a causer pays or beneficiary pays type approach to allocation of network costs. However, interconnector assets, and further investment in such assets, provide a range of benefits to transmission customers, including reserve sharing and reliability, lower production costs and congestion, and competition benefits. These benefits apply regardless of the direction of flow;
- implementing the modified LEC would likely to be challenging from an administrative perspective, because of the need to develop a uniform national charging methodology. Those TNSPs whose methodologies would not be consistent with the national methodology would have to amend their processes accordingly. In respect of the modified LEC, requiring TNSPs to apply the CRNP methodology twice (once without and once with the inter-regional load points) would also create more work in the process; and
- the modified LEC would be based on energy flows between regions, which depend on a confluence of factors, such as the location and dispatch decisions of generators, congestion, outages and bidding behaviour in each region. The level of such a charge would therefore be likely to be volatile and unpredictable. Excessive volatility in charges (particularly where such charges would be unpredictable and of significant quantum) tend to detract from economic efficiency because they dilute the signalling properties of the charge and contribute to uncertainty.

Below is a summary of the advantages and disadvantages of the modified LEC.

Table 5.1 Advantages and Disadvantages of the Modified LEC

Advantages	Disadvantages
More cost-reflective than current arrangements	Requires agreement on a uniform national transmission charging methodology
Does not require TNSPs to coordinate to apply the CRNP methodology	Requires the CRNP methodology to be applied twice
	More difficult to charge regions which are not adjoining

5.6 Questions

Question 9	**If a LEC were chosen, would the modified LEC be preferable to the original LEC proposed in the draft Rule determination?**
Question 10	**If a LEC were chosen, would there any other difficulties in applying the modified LEC?**
Question 11	**Is the modified LEC preferable to the other inter-regional transmission charging options proposed in this Discussion Paper?**

6 Option 2: Cost Sharing

As an alternative inter-regional transmission charging option to the LEC, a Cost Sharing option was presented in the NTP Review. At the time, this option was considered as disadvantageous because it would impose charges that recover sunk costs on importing region customers which would be unlikely to provide a good proxy for LRMC and be unlikely to promote dynamic efficiency. On the other hand, this option should be simpler to apply than a LEC, and would be more consistent with the view that the benefits of inter-regional transmission tend to be spread widely and would not be attributable to the actions of individual network users.

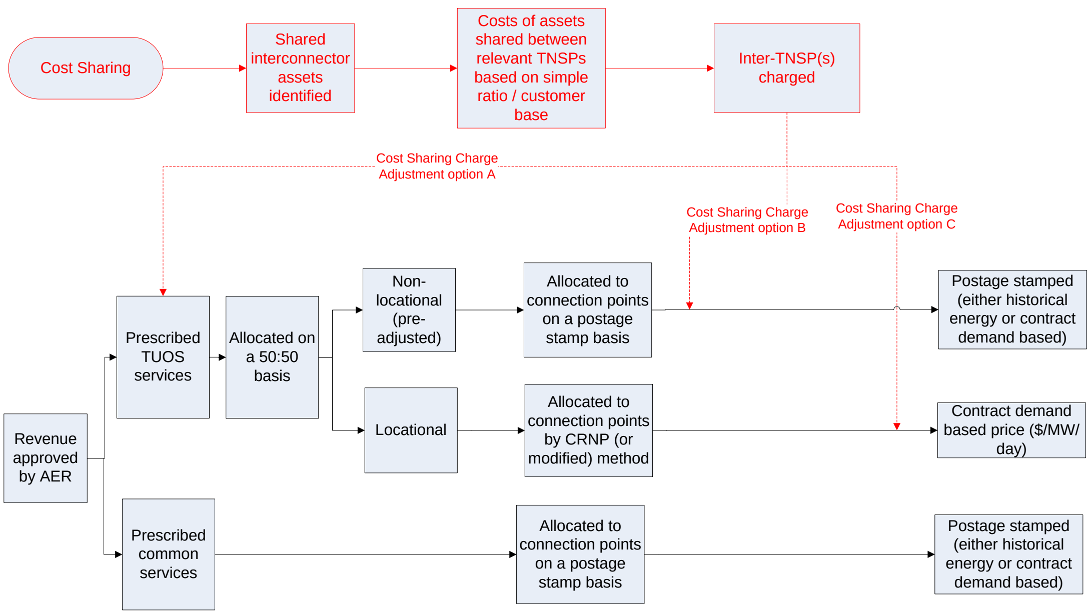
This chapter revisits this option in the context of the assessment framework for developing a uniform national inter-regional transmission charging regime and methodology.

6.1 Description of the Cost Sharing

The Cost Sharing option involves costs of assets used for inter-regional flows being shared. There are two ways in which the costs could be shared: either between the relevant adjacent TNSPs or across all TNSPs in the NEM. There are two key steps in this process: identifying the assets, and then apportioning their costs to TNSPs. These two steps are further described below.

Once the costs have been shared amongst the TNSPs, the charges would then be recovered by each TNSP from its own customers. This may be done by making adjustments to either the prescribed locational TUoS service component of the intra-regional TUoS charge, on a postage stamp basis through the prescribed non-locational TUoS service component of the intra-regional TUoS charge, or adjusted in the revenue requirement for intra-regional prescribed TUoS services.

Below is a diagrammatical description of how the Cost Sharing option would work.



6.2 Identifying the Assets Included

The first step in the Cost Sharing option is to identify the assets whose cost is to be shared amongst the relevant TNSPs or all TNSPs in the NEM. This could include new and existing assets or new assets only.[21] A load flow analysis could be applied NEM-wide to determine which assets would be utilised for the purposes of allowing inter-regional flows (noting however that costs would not be allocated at the point the load flow analysis is being conducted). This may allocate only portions of assets to be recovered inter-regionally, depending on the results from the load flow analysis. Additional options that were proposed in the NTP Review (albeit more related to identifying new assets) included:

- an application of a technical threshold e.g. transmission line voltage rating;
- a central body responsible for determining the new assets based on a set of defined criteria; or
- an agreement between the relevant TNSPs.

The NTP Review suggested that the first approach for identifying new assets would not be practicable unless it was done on a NEM-wide basis. In the NTP Review, the second approach was suggested and was proposed to be based on the criteria developed by the Inter Regional Planning Committee (IRPC) for assessing material inter-network impacts of transmission augmentations. This was considered to be a more ideal approach given the familiarity of the criteria to TNSPs and its clear specification; however, it was considered that this approach may create an administrative burden on the central body. The final approach was considered to be less likely to be consistent and more susceptible to gaming.

In the NTP Review, only the costs of new investment in shared interconnector assets were included in the option. Benefits of considering only the new assets were the reduced price impact of excessive charges if both old and new assets were included and the lack of a dynamic efficiency rationale for including existing assets in such a charge (because the costs of existing assets are sunk). However, there are some issues with focussing on new assets only:

- a new process would have to be developed to identify new assets (that is, establish the inter-regional impact of a new transmission asset);
- dynamic efficiencies may be limited because even with new interconnector assets the costs would largely be recovered from importing region customers after they have been sunk (that is, there may be limited prospect for a charge based on new interconnector assets to influence behaviour); and
- the lumpiness of the transmission network infrastructure means that the LRMC of transmission at a particular location would likely fall significantly after a new

21 New assets may be defined on the basis of a time period to be determined (which may be linked to the frequency of inter-regional transmission charging assessments).

investment to enhance transmission capability to that location. However, this would not be reflected under a Cost Sharing option, further reducing the forward-looking signalling of this approach.

The Commission seeks stakeholder views on whether both existing and/or new assets should be included in a Cost Sharing arrangement. This will also be informed by modelling that the Commission intends to undertake for this particular option. A load flow analysis approach for identifying assets could be the simplest and incremental approach as it could be based on existing load flow analysis undertaken by TNSPs. Given the Commission's objective for a consistent methodology, some TNSPs may need to adjust their current load flow analysis practices.

6.3 Determining and Allocating the Costs

Once the relevant assets have been identified, the costs for these assets would then be allocated to the relevant TNSPs. The NTP Review identified three possible approaches:

- negotiation between TNSPs on a case-by-case basis;
- a simple split of the costs based on equal amounts; or
- a load-flow modelling analysis.

The first approach for cost allocation would entail negotiation and agreement between relevant TNSPs on what cost of assets would be shared. This was seen as leading to potential dispute between TNSPs in order to reduce their share of the costs. The second approach of splitting the costs, and in fact allocating the costs broadly on a postage stamp basis, may be the simplest approach. However, such an approach implies no forward signalling. The third approach applies load flow modelling to determine the cost allocation on the basis of energy flows between regions. This would represent the most forward looking approach but would face similar problems to the modified LEC with respect to determining what NEM-wide methodology should be applied by TNSPs or a central body (to be determined at a later stage).

While not considered in the NTP review, a further approach to allocating costs could be to base such an allocation on market modelling such as that undertaken under the RIT-T. The RIT-T would better capture the broader benefits of new transmission investment relative to an utilisation based approach, which relates to reserve sharing, lower congestion and enhanced competition. These benefits tend not to be directly related to the level of utilisation of interconnector assets. However, this approach could only practicably be applied to new interconnector assets, and not existing (sunk) assets.

Another consideration is the frequency of the determination and allocation of the costs. Cost allocation could be done on a regular basis (e.g. annually or every regulatory control period), a once-off basis (e.g. when the asset is commissioned), or other basis (e.g. material inter-network impact has been identified).

Once these costs have been allocated to the appropriate TNSPs, the next step is to consider how they can recover these from their own customers in the form of a charge. This can be done on a postage-stamp basis where the costs would be evenly smeared across all customers via the prescribed non-locational TUoS service charge, on a locational basis through the prescribed locational TUoS service charge, or adjusted in the revenue requirement for intra-regional prescribed TUoS services.

6.4 Preliminary observations

Compared to the LEC, the Cost Sharing option would be easier to implement given its simplicity in design and may also avoid having to make decisions on some of the design features discussed in Chapter 4. This would result in less administrative burden being placed on TNSPs to implement such a scheme. Further, such a charge would not be intended to provide a forward signal and therefore could be implemented in a way that would be stable and predictable for transmission customers.

However, in providing a simple inter-regional transmission charging approach, the price signalling to customers would be lost as the costs would be shared between TNSPs and not based on proportionate use of the assets. On the other hand, a Cost Sharing approach which shares costs widely on a postage stamp basis would be consistent with a perspective that the benefits of inter-regional transmission tend to be diffuse and that particular causers (or beneficiaries) of existing and future inter-regional transmission assets would be difficult to identify, and likely to change over time with shifting patterns of generation investment and demand growth.

As with the modified LEC, without a central body administering the inter-regional charging regime, the Cost Sharing option may not be a long term solution. On the other hand, it could be seen as a transitional solution as part of the long term design. Depending on the length of time that the Cost Sharing option would apply to all TNSPs, this may have an impact on the perceived stability and certainty to TNSPs, customers and investors.

At this stage, the potential cost impact of the Cost Sharing option on TNSPs and customers is uncertain. Modelling of the Cost Sharing option based on a set design would assist in estimating the potential impact.

Below is a summary of the advantages and disadvantages of the Cost Sharing option.

Table 6.1 Advantages and Disadvantages of the Cost Sharing option

Advantages	Disadvantages
Provides some transparency and predictability	Including only new assets (if this option is chosen) could lead to administrative disputes over the methodology applied
Avoids some of the current differences between TNSPs' application of transmission pricing	Simple allocation of costs would be arbitrary and not reflective of customer use

Advantages	Disadvantages
	Unlikely to form the basis of a future NEM-wide integrated transmission charging methodology

6.5 Questions

Question 12	**If a Cost Sharing option was chosen as the inter-regional transmission charging approach, which methodology should be used to identify the assets which allow for inter-regional flows? For instance, could the assets be determined by a load flow analysis?**
Question 13	**Which assets should be covered in an inter-regional transmission charging arrangement? Should the cost of existing transmission assets used to allow for inter-regional flows be included? Should there be a technical threshold applied in order for assets to be included?**
Question 14	**In allocating costs under a Cost Sharing option, what methodology should be used? For instance, should it be allocated on a simple split based on the size of a TNSP's customer base?**
Question 15	**Under a Cost Sharing option, how should the costs be recovered from customers? For instance, should it be recovered on a postage stamp or locational basis?**
Question 16	**Would a Cost Sharing option be preferable to the other options proposed?**

7 Option 3: NEM-wide CRNP

Similar to the modified LEC proposed in Chapter 5, this option includes a uniform national inter-regional transmission charging regime which operates separately to the intra-regional transmission charging regime. In contrast to that approach, however, in this option the charging methodology is applied once, on a NEM-wide basis, rather than being applied separately by each TNSP for assets in its region. Among other things, this allows a TNSP in one region to recover from customers in a *non-adjoining* region a contribution to its transmission network costs. These features are explained further below.

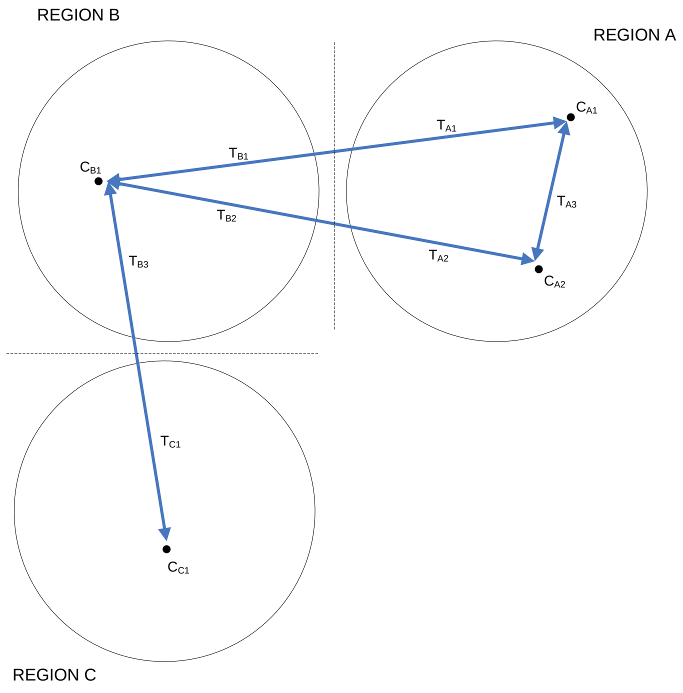
7.1 Description of the NEM-wide CRNP

This option requires a NEM-wide CRNP methodology, which operates independently of the intra-regional CRNP methodology. However, given the differences between the charging methodologies used in each region, a decision must be made as to which components (such as standard CRNP or modified CRNP) would be incorporated. These components could be either specified in the NER or else agreed on by the TNSPs together.

Once the NEM-wide CRNP methodology is determined, the TNSPs would jointly apply it (or alternatively, it could be applied by a central body) to determine the allocation of the costs of every asset in the NEM which contributes to inter-regional flows to every customer in the NEM. That is, the CRNP methodology would be run once for the entire NEM and it would be completely separate to intra-regional transmission charging. The national run of the CRNP methodology would only focus on inter-regional flows. A particular customer in the NEM would be allocated costs for relevant assets in all other regions in the NEM. These costs would represent a proportion of the costs of each asset, depending on the relative use the customer makes of that asset. The CRNP methodology would then sum all of the costs for each customer. Each TNSP would recover the total of these costs from each customer in its region (though for the purposes of the settlements described in the next paragraph it must be possible to break each customer's costs down on a region by region basis).

Following this a series of inter-regional settlements occurs. A TNSP in one region would pay to a TNSP in a second region all of the costs the first TNSP has recovered from its customers in respect of assets in the second region. This would occur for all TNSPs in the NEM. Each TNSP would then rebate any positive amount it receives to its customers, or else recover any negative amounts from its customers.

This option is most easily described by using a diagram, as set out below.



The diagram shows three regions: A, B and C. There are four customers: C_{A1}, C_{A2}, C_{B1} and C_{C1}. There are also seven transmission assets: T_{A1}, T_{A2}, T_{A3}, T_{B1}, T_{B2}, T_{B3} and T_{C1}. It is assumed in this example that every asset contributes to the flows to every customer. After a uniform national CRNP methodology is agreed on, the process would be as follows for customer C_{A1} (and similarly for the other customers):

Step 1: The CRNP methodology would be applied to determine how each of the seven transmission assets contributes to inter-regional flows to customer C_{A1}.

Step 2: The cost of each of those assets would be allocated to customer C_{A1} in proportion to the results of the analysis in the previous step.

Step 3: The costs allocated to customer C_{A1} in respect of assets in regions B and C would be totalled to produce an inter-regional charge payable by customer C_{A1}.

Step 4: Customer C_{A1}'s intra-regional charge determined by TNSP A in respect of assets in region A remains unchanged.

Step 5: Customer C_{A1} pays its inter-regional charge for assets in regions B and C to TNSP A.

Step 6: TNSP A pays TNSPs B and C the charges it has recovered from customer C_{A1} for regions B and C respectively.

7.2 Identifying the assets included

All assets would as a matter of course be included. A CRNP methodology would be used to determine the proportion of the costs of each asset which would be recovered from each customer. The assumption used in the example above that every asset contributes to the flows of every customer would unlikely to hold true in practice and some assets may not be recovered inter-regionally.

Since the inter-regional calculations would be performed separately to the intra-regional calculations a separate inter-regional application of a CRNP methodology would be performed by all of the TNSPs working together.

7.3 Determining and allocating the costs

The same CRNP methodology would be applied in respect of every customer in the NEM. This would require that choices be made between the different variables that can be used in applying a CRNP methodology; some of these may be prescribed in the NER and some may be left to TNSPs to determine together. Certain of these variables are discussed in depth in Chapter 4.

7.4 Preliminary observations

This methodology would offer many of the same advantages and disadvantages as the modified LEC described in Chapter 5. It would recover a portion of the fixed costs of inter-regional transmission in a way that minimises distortion to current network use, while also using some of the network sunk costs to signal future network augmentation requirements (and thus determine which region would be causing the need for those requirements). However, the Commission seeks views on the extent to which utilisation in this fashion appropriately reflects the broader market benefits delivered by inter-regional transmission. Compared to the modified LEC, this methodology would offer greater cost-reflectivity in that a customer would be charged not just for its use of assets in adjoining regions but also for those assets in non-adjoining regions.

On the other hand, in comparison to the modified LEC, this methodology would be administratively more difficult to implement. While the modified LEC would be applied bilaterally, that is, an exporting region would apply a modified LEC to each of its one (or more) adjoining regions, the NEM-wide CRNP methodology would be applied multi-laterally and would require all TNSPs to agree how the national CRNP methodology would be coordinated (or alternatively, it could be applied by a central body). This may need to occur every year. The process of applying the methodology would be streamlined if the NER were to specify some or all of the variables that comprise the CRNP methodology. Whichever approach is taken, however, some TNSPs would be required to adapt to a new approach to transmission charging (as with the modified LEC above).

Below is a summary of the advantages and disadvantages of the NEM-wide CRNP option compared to the modified LEC option described above.

Table 7.1 Advantages and Disadvantages of the NEM-wide CRNP option compared to the modified LEC

Advantages	Disadvantages
This methodology would enable customers to contribute to the cost of assets from which they benefit in regions which are not adjoining	All of the transmission businesses would be required jointly to determine how the CRNP methodology would be applied (or alternatively, it could be applied by a central body.

7.5 Questions

Question 17	**Would it be possible to apply a CRNP methodology on a NEM-wide basis? If so, what difficulties would be faced?**
Question 18	**If so, how easy would it be for the transmission businesses in the NEM jointly to implement a NEM-wide CRNP methodology?**
Question 19	**Would a NEM-wide CRNP methodology be preferable to the other options proposed?**
Question 20	**Are there any options for a uniform national inter-regional transmission methodology (other than the three options presented in this Discussion Paper) that should be considered?**

Abbreviations

AARR	Aggregate Annual Regulated Revenue
ACS	Attributable Cost Share
AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	Annual Service Revenue Requirement
Climate Change Review	Review of Energy Market Frameworks in Light of Climate Change Policies
CRNP	Cost Reflective Network Pricing
IRPC	Inter Regional Planning Committee
LEC	Load Export Charge
LRMC	long run marginal cost
MAR	Maximum Allowed Revenue
MCE	Ministerial Council on Energy
NEM	National Electricity Market
NEO	National Electricity Objective
NTP	National Transmission Planner
ORC	optimised replacement costs
RIT-T	Regulatory Investment Test for Transmission
Rules	National Electricity Rules
SRA	settlement residue auction
SRMC	short run marginal cost
TUoS	Transmission Use of System

A Economic Reasoning behind the Assessment Framework

In developing the assessment framework in Chapter 3, some important economic concepts with relevance to transmission pricing were considered. These concepts are discussed below.

A.1 Static and dynamic efficiency

Static efficiency refers to the short term, when capital and technology do not change. It comprises both a productive efficiency and allocative efficiency element:

- Productive efficiency is concerned with producing output at the lowest possible cost to society, and therefore requires the lowest cost combination of inputs to produce a particular output; and
- Allocative efficiency is achieved when the price charged to a consumer for an additional unit of a good produced, or service provided, is equal to the cost of producing that unit (marginal or incremental cost). This ensures that the pricing system operates to allocate scarce resources to the uses that consumers value most highly. A price lower than marginal costs would imply that the last unit of a good produced or service provided did not confer sufficient benefits to offset the costs of providing that good or service. A price higher than marginal costs means that less of the good is produced relative to what is desired. Both shift resources away from those areas where they are more highly valued, causing a misallocation in society's resources.

Dynamic efficiency relates to the optimal allocation of resources (investment) over time when capital and technology can change.

Options for transmission charging should encourage both static and dynamic efficiency. However, because of the unique characteristics of transmission these objectives tend to conflict with one another, requiring trade-offs to be made. The characteristics of transmission are briefly considered below.

A.2 Characteristics of transmission - scale economies and network externalities

Charging for transmission is complicated by the fact that it is characterised by strong economies of scale and network externalities. Economies of scale mean that the average cost per unit of output decreases as output increases. There are two relevant dimensions to scale economies:

- Technical scale economies arise from the high fixed costs of building assets. That is, it is cheaper to build one transmission line of a given capacity than to build two lines each of half the same capacity. For this reason, it is normally efficient to build some excess transmission capacity to cater for future demand. The implication of this is that at any one point in time there may be significant unused capacity in the network so that the SRMC of using the network may vary greatly over time. For example, when there is excess capacity the marginal cost of using that transmission capacity may be close to zero; however, the marginal cost of using the next increment of capacity where it is fully utilised may be very large (potentially hundreds of millions of dollars if the voltage of the network needs to be upgraded for instance).

- Firm scale economies cause the average cost of a single firm to decline over the full range of output of the entire market (for instance because of technical scale economies or network externalities). Such firms are called natural monopolies because it is cheaper for one firm to supply the entire market than several firms. Under these circumstances, the operation of a competitive market without regulation will ultimately result in a natural monopoly. A natural monopoly prices its output well in excess of its SRMC (causing a misallocation of resources), and for this reason such firms are usually regulated.

The pricing and charging of transmission are also complicated by the presence of externalities, which give rise to "public good" characteristics. A well functioning market requires the ability of suppliers to identify and charge consumers for the services they provide, or exclude them if they are not willing to pay for these services. However, in a transmission network it is not always possible to identify who is consuming a service at a particular time. This is primarily because of the effect of loop flows. Loop flows cause energy flows to split across many parallel paths, including parts of the network some distance away from the primary path, which means that the actions of individual network users can impact other network users. The loop flow externality has the following important implications for network pricing:

- it may be difficult to link use of a transmission asset within the shared network to specific users (this applies less to radial or connection assets). This is because the degree to which a customer uses a specific asset depends on the generation and consumption decisions of all other network users. A pure causer pays approach may therefore be difficult to implement if specific causers of network investment cannot be identified; and

- the presence of network externalities means that the benefits of new investment in the network will to tend to be shared among many or all network users (for example, such benefits include lower congestion costs, enhanced reliability, and competition). This creates free riders since it is not possible to exclude users from benefiting from the network. This is a key reason why most transmission investment in electricity markets is regulated (such as through the RIT-T) because there may be little incentive for private parties to invest in transmission if they are unable to identify the beneficiaries and extract a charge for use of the asset once it is built.

These characteristics of transmission introduce significant complexity in developing an appropriate transmission charging methodology. First, as a consequence of loop flows it may be difficult in some circumstances to identify specific causers or beneficiaries of transmission investment. Second even where specific causers can be identified, technical and firm scale economies mean that charges which are set to ensure allocative efficiency (prices equal to SRMC) will substantially under recover the costs of the network (since SRMC is well below average costs for a natural monopoly). For these reasons structuring an inter-regional charge will require certain trade-offs to be made. These are discussed below.

A.3 Structuring charges to meet static (allocative) efficiency objectives

The majority of a TNSP's allowed regulated revenue (and therefore most of what needs to be recovered through a TNSP's pricing methodology) relates to the existing physical infrastructure of the network. A TNSP's existing assets have little alternative use beyond conveyance of electricity; that is, the assets are sunk, and the costs of operating those assets largely do not vary with the level of use.

The SRMC of transmission are principally constraints (which reflect the scarcity value of transmission) and losses. These make up only a small proportion of the overall fixed costs of the network.

For TNSPs, the marginal costs of the network lie well below the average costs, which reflect the technical and firm scale economies associated with natural monopoly discussed above. This means that if TNSPs were to charge solely to meet allocative efficiency objectives then they would under recover the costs of the network compromising dynamic efficiency. Some form of charging mechanism must therefore be implemented to recover the fixed costs of the network.

However, the costs of the physical network are not relevant to the determination of SRMC because they are fixed regardless of the decisions of network users. Therefore, if TNSPs were to recover the fixed costs in a single variable charge from network users, it is likely that this would undermine allocative efficiency objectives, since such a charge would significantly exceed the marginal costs of network use. Users would reduce their utilisation or move to different locations in the network despite the costs of the network being largely invariant to those decisions. That is, the price would be above the SRMC and lead to under-utilisation of the network. It is for this reason that costs that are invariant to incremental use of the network use should be recovered in a way that in turn does not vary with use; that is, in a way that minimises the impacts of such a charge on network utilisation.

One way this could be addressed is through implementation of a two-part tariff consistent with the Ramsey pricing principle, which attempts to encourage efficient use of the network while allowing full recovery of fixed costs. The Ramsey pricing principle suggests that a two-part tariff is charged that differs between users on the basis of willingness to pay. The variable charge would recover the SRMC (pricing of constraints and losses) and a fixed charge would recover the fixed cost so of the network and would therefore not vary with use (to avoid discouraging network utilisation).

In the NEM, the SRMC of network usage are essentially congestion and losses. These are priced in the wholesale market, and arguably therefore do not require a separate charge from TNSPs. This means TNSPs simply concerning themselves with recovery of a fixed or "lump sum" of allowed regulated revenue in a manner that does not interfere with use of the network (that is, focus on static efficiency only). Importantly a fixed charge for network users should not be so large as to exceed their "willingness to pay" for access to the network. If the charge exceeds willingness to pay, then this may lead to inefficient network by-pass. While the exact willingness to pay of a particular network user is difficult to determine precisely, the charge is usually recovered from customers at peak demand times, as it is assumed customers' willingness to pay will be highest at these times.

A.4 Structuring charges to meet dynamic efficiency objectives

Least distortionary fixed cost recovery is used if the purpose of a transmission pricing methodology is solely to promote efficient use of the "existing" network (since SRMC signals in the wholesale market would provide for efficient future development of the network). However, if the SRMC signals in the wholesale market are considered inadequate for the task of driving efficient network development over time, then transmission pricing may also be used to play a role in supporting this latter objective. This requires that a portion of the sunk network costs of the network are oriented to providing a forward looking locational signal. For example, charges could be structured to reflect the LRMC of the network in particular areas (the charge would therefore vary by location to reflect future network requirements).

LRMC charges are based on the notion that if the transmission prices are based on the least distortionary cost recovery only, then transmission customers may locate in areas remote from generation sources. Or conversely, generators may locate remotely from transmission users, or in areas where transmission capacity is already heavily utilised. This would bring forward the need for network investment in those areas (and lead to inefficiently high network costs over time). Therefore, network users could be charged in a manner that reflects an estimate of the forward looking costs of their decisions. An important requirement for structuring the charge in this way is that network users have the ability and incentive to respond to such a charge, or else there will be little change in efficiency. This issue may be more relevant for an inter-regional charge, as arguably the elasticity of response to an inter-regional charge (which in effect should encourage network users to switch from regions where inter-regional charges are high to those regions where they are low) is likely to be lower than elasticity of response to an intra-regional charge, since network users are more likely to change location within their own region in response to an increased charge.

A further important consideration is that implementing a charge that accurately reflects the LRMC of augmenting the network is informationally complex, as it relies on future network utilisation and locational decisions of all other users of the network. Further, due to economies of scale an LRMC charge can be very high once the capacity of an asset becomes fully utilised, but once new investment does occur, and spare capacity is created, such a charge may fall close to zero for substantial periods of time. Such large fluctuations in forward looking costs can make LRMC charging difficult to implement in a practical sense and causes price shocks and increased investor uncertainty. This is one reason why CRNP methodology is used in the NEM, which attempts to provide a proxy for LRMC based on the level of utilisation of network elements (but arguably only loosely reflects the LRMC of network augmentation).

As noted in section A.3, however, it should be recognised that SRMC signals in the wholesale market provide some signals for efficient future network development. Generators are impacted by constraints and losses which provide some incentive for them to locate in areas of surplus transmission capacity. Generators tend to pass these costs through to customers in their contracts, which consequently also provides incentives for transmission end users to also take transmission locational factors into account in their locational decisions. For this reason, it is important that forward looking transmission charges do not over-signal the need for network investment (and thereby deter efficient utilisation of the existing network).

As considered in detail in Chapter 4, some of the TNSPs' current transmission charging approaches within NEM regions have chosen a 50:50 split between static and dynamic efficiency objectives. That is, such charges are partly structured to recover a proportion of overall fixed costs in a non-distortionary manner (a postage stamp charge that is based on historical use or contracted demand) and partly also to provide some dynamic signals with regard to network use (CRNP methodology).

A.5 Structuring charges to reflect the public good characteristics of transmission

It is important to note that allocative and dynamic efficiencies can only be achieved if costs are appropriately allocated to causers or beneficiaries of network investment. As the Commission has discussed above, the public good characteristics of transmission means that it may be difficult to isolate the causers of, or beneficiaries from, transmission investment in the shared network. Thus charges set solely on the basis of causation may be problematic because the causal link between individual users' decisions and the incurring of transmission costs may not be clear.

This issue may be particularly relevant for inter-regional transmission assets, which due to their size tend to be subject to significant economies of scale and network externalities, which means the benefit will fall broadly across regions. These benefits may include maintaining reliability and reserve sharing between regions, lowering congestion (in turn leading to reduced trading risks between regions) and enhanced competition. Importantly, these benefits apply regardless of direction of energy flows between regions. Thus, applying cost reflectivity in charging for transmission assets with significant public good characteristics implies that such a charge should be spread broadly across users.

A.6 Procedural and implementation issues

The above issues are primarily concerned with the direct consequences of an efficient inter-regional transmission charge on the behaviour of network users. However, there are also indirect consequences that arise from introducing a new set of arrangements (in economics often called transactions costs) that must also be taken into account to ensure such arrangements do not create issues or distortions elsewhere in the energy supply chain. These consequences include the implementation and administrative costs for TNSPs and network users in calculating a potentially complex new charge (for instance requiring implementation of new methods, procedures, systems, models and training etc) and the impacts of a complex new charge on the ability of a firm to understand or predict its financial exposures over time.

Network users tend to operate in competitive upstream or down stream markets, which means it is important that any new regulated charges are transparent, stable and predictable so that they do not create undue uncertainty with regard to the effective operation and investment decisions of firms. For example, if a new inter-regional charge is so high and/or volatile so that it deters access to the transmission network altogether (rather than a more efficient locational decision in a different part of the network), then this may result in inefficient by-pass of the network or new entry into the energy sector altogether.

B Current intra-regional transmission charging arrangements

Regulated under the National Electricity Rules, there are four categories of 'prescribed transmission services'. These include prescribed entry, prescribed exit, prescribed common transmission and prescribed TUoS services.

'Prescribed common transmission services' provide equivalent benefits to all transmission customers on the network without any differentiation based on their location. Examples of assets that are used to provide these services include TNSP's control buildings, protection systems, communication systems, and earth mats.

'Prescribed TUoS services' provide different benefits to different transmission customers depending on their location; for example, the level of transmission infrastructure required. This generally constitutes the majority of the prescribed transmission services costs. For the purposes of this Discussion Paper, prescribed entry and prescribed exit services are not considered.

The Rules governing transmission pricing allow a regulated TNSP to earn revenue to recover its planning, operation and augmentation costs. The transmission pricing process in the Rules outlines what is to be recovered and who it should be recovered from.

The costs of the prescribed transmission services to be recovered are based on a Maximum Allowed Revenue (MAR) set by the Australian Energy Regulator (AER), which is adjusted, to create AARR. This is the revenue that is recovered through costs relating to prescribed transmission services only, excluding 'negotiated' and unregulated services.

The Attributable Cost Share (ACS) for each category of service (i.e. prescribed entry, prescribed exit service, prescribed common transmission and prescribed TUoS services) is then calculated. For each service, this is the ratio of costs of the transmission system assets directly attributable to the provision of that category of service to the total costs of all of the TNSPs' transmission assets directly attributable to the provision of prescribed transmission services.

Based on the ACS for each category of service, the AARR is then allocated to categories of prescribed transmission services. This is called the ASRR.

For costs related to the provision of prescribed TUoS services, its ASRR is split into locational and non-locational components by 50:50 (except where a modified CRNP is used as discussed later). The split is arbitrary, largely to avoid excessive cost volatility for loads under the locational charging methodology.

Below is an explanation of how prescribed locational and non-locational TUoS, and prescribed common transmission services costs are currently determined and charged to customers.

B.1 Prescribed locational TUoS service component

For the prescribed locational TUoS service component, its portion of the ASRR is allocated to the individual connection points based on their proportionate use of shared network utilisation via the standard Cost Reflective Network Pricing (CRNP) method or modified CRNP. The prescribed locational TUoS service component is also adjusted for estimated inter-regional settlements residue proceeds via the standard CRNP (or modified version).

The unadjusted prescribed locational TUoS service price ($/MW) at each connection point is then determined by the product of the prescribed locational TUoS service portion of the ASRR and the connection point's ORC divided by the forecast contract maximum demand over a particular period.

A 2% tolerance requirement applies to the prescribed locational TUoS service prices.[22] This is a smoothing factor as the Rules require that the prices must not change by more than 2% per annum at connection points relative to the load weighted average prescribed locational TUoS service price for the region.

The balance of any revenue shortfall or over recovery resulting from these price caps is recovered or offset as appropriate by adjusting prescribed non-locational TUoS service prices and charges. Based on the 2% tolerance, the final prescribed locational TUoS service price is then derived: 2% Adjusted Locational TUoS price x Maximum Demand.

B.2 Prescribed non-locational TUoS service component

For the prescribed non-locational TUoS service component, its ASRR is smeared across all connection points (postage stamp). This is based on historic energy consumption at the connection point.

The prescribed non-locational TUoS service component is adjusted for over/under recovery, settlement residues, settlement residue auctions (SRAs) and the 2% tolerance requirement (as discussed above). This becomes the adjusted prescribed non-locational TUoS service.

The charge for this component can be either:

- historical energy based ($/MWh) – a standard rate; or
- demand (capacity) based ($/MWh or $/MW) – a contracted capacity rate which requires a contract between the customer and the TNSP, including a fixed Nominated Contract Maximum Demand, and a penalty is applied if the Nominated Contract Maximum Demand is exceeded. This option is better for loads with high load factor.

22 An exception to the 2% tolerance requirement for prescribed locational TUoS service prices is where there is a material change in load at the connection point that is equivalent to the creation of a new connection point.

For historical energy based price, this is derived as follows: ASRR for Adjusted Prescribed Non-locational TUoS Service / Total Historical Energy.

For demand based price, this is derived by the energy based price converted to demand rate ($/MWh/month or $/MW) using the Median Load Factor.

For historical energy based charge, this is derived from the historical energy based price multiplied by the metered energy at the connection point in the equivalent billing period during previous financial year.

For demand based charge, this is derived from the demand based price multiplied by the fixed Nominated Contract Maximum Demand for the connection point referable to that billing period.

B.3 Prescribed common transmission service

Similar to the prescribed non-locational TUoS service, the prescribed common transmission service is charged on a postage stamp basis, based either on historic energy consumption at the connection point or contracted demand.

For historical energy based price, this is derived as follows: (ASRR + Opex for prescribed common transmission services) / Total Historical Energy

For historical energy based charge, and demand based price and charge, this is derived in the same way as the prescribed non-locational TUoS service.