RULE CHANGE

Australian Energy Market Commission

SECOND DRAFT RULE DETERMINATION

National Electricity Amendment (Inter-regional transmission charging) Rule 2013

Rule Proponent(s)

Ministerial Council on Energy

6 December 2012

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

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About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011, COAG established the Standing Council on Energy and Resources (SCER) to replace the MCE. The AEMC has two principal functions. We make and amend the national electricity, gas and energy retail rules, and we conduct independent reviews of the energy markets for the SCER.

Summary of second draft determination

In this second draft determination the Australian Energy Market Commission has determined to make a more preferable rule in relation to the inter-regional transmission charging rule change request. This second draft rule change seeks to introduce a modified load export charge. This charge will mean that prices better reflect the benefit derived by customers from costs incurred in a neighbouring transmission region. This will enhance the cost reflectivity of transmission prices as well as remove a minor disincentive on transmission network service providers undertaking network expenditure where the benefit, or a significant part of the benefit, is derived in another region.

On 15 February 2010, the Ministerial Council on Energy submitted a rule change request to the Australian Energy Market Commission seeking to implement an inter-regional transmission charging mechanism. This rule change sought to introduce an inter-regional transmission charge in the form of a load export charge to neighbouring National Electricity Market regions. Currently, customers in a region who benefit from the use of transmission assets in a neighbouring region under the rules do not directly contribute towards the cost of those assets.

Modelling undertaken by transmission network service providers showed that the calculation of load export charge could vary across the National Electricity Market in part as a result of different methodologies utilised in different regions rather than any underlying fundamental change in the use of the network. In response to stakeholder feedback on the draft rule determination the Commission undertook further analysis and consultation on options for an inter-regional transmission charge.

The Commission consulted on three options in addition to the original rule change proposal and a fourth was put forward by a group of generators based on the regulatory investment test for transmission. This means the options under active consideration were the:

- Status quo
- Load export charge
- Modified load export charge
- National electricity market -wide cost sharing
- Cost sharing
- Allocation based on the regulatory investment test for transmission businesses.

These options are outlined in more detail in section 4

Following further analysis and modelling, the Commission has determined that the modified load export charge best meets the National Electricity Objective as it provides an appropriate balance of cost reflectivity, transparency, stability and cost of implementation. The Commission has also determined that the modified load export charge should be allocated on a locational basis, as a postage stamp basis would undermine cost reflectivity and introduce another level of inconsistency between jurisdictions.

The Commission notes the interaction between the matters considered as part of the inter-regional transmission charging rule change and the Transmission Frameworks Review. Recommendations arising from the Transmission Frameworks Review will be reported to the Standing Council on Energy and Resources (SCER) during 2013. Following SCER's consideration of that report, rule changes and other development work would be required to implement any adopted recommended changes to the current transmission arrangements. This process is likely to occur over a significant period of time. The Commission is of the view that the introduction of an inter-regional transmission charge based on the modified load export method will better meets the National Electricity Objective and its implementation will deliver consumer benefits in the short to medium term. The possibility of future changes to the transmission arrangements in the medium to long term arising from the Transmission Frameworks Review is not an impediment to the introduction of this rule. Both the second draft rule and the Transmission Framework Review are working towards an enhanced nationally consistent approach to transmission charging and investment.

The introduction of an inter-regional transmission charge does not alter the revenue to be kept by transmission networks. The Commission recognises that some customer's will face a slightly higher charge as the result of the introduction of the inter-regional transmission charge. However, other customers will face slightly lower transmission charges. From a total national electricity market perspective there are no additional costs being paid by customers.

The Australian Energy Market Commission welcomes submissions on this draft determination or the draft rule. Submissions are due by 18 January 2013.

Contents

1 Ministerial Council on Energy's rule change request

1.1 The rule change request

On 15 February 2010, the Ministerial Council on Energy (MCE) (rule 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 proposes that new inter-regional transmission charging arrangements be introduced such that transmission businesses in each region would levy a new charge - a load export charge - on transmission businesses in adjoining regions. This new charge would reflect the flow of electricity from one region to the adjoining regions.

1.2 Rationale for rule change request

Currently under Chapter 6A of the National Electricity rules (rules), a transmission network service provider (TNSP) recovers its costs in building and operating its transmission system from customers within its region.[1] The pricing provisions under the rules, which set out how these costs are to be recovered, are based on a set of principles and require TNSPs to develop separate prices for each category of prescribed transmission service.[2] Each TNSP must also publish a pricing method which, in part, sets out how the revenue to be recovered has been allocated to each category of prescribed transmission service.[3]

The National Electricity Market (NEM) consists of five interconnected regions where electricity may be exported and imported between regions. When electricity flows between regions, the provision of electricity to customers in the importing region will utilise the network in the exporting region. Under the rules, however, the transmission system charges in the importing region are based on the costs of the TNSP in the importing region only. They do not reflect the costs of utilising the assets of the exporting region's network. By not paying charges that reflect the cost of the transmission network in the exporting region, customers in the importing region, in effect, could be paying a network price that is lower than they should and those in the exporting region could be paying a higher network price than they should.

1 Clause 3.6.5(a)(5) of the rules provides for jurisdictions to establish inter-regional charges through inter-governmental agreement. However, in practice, inter-regional transmission service payments have been negotiated only between South Australia and Victoria.

2 The categories of prescribed transmission services are set out in clause 6A.23.4 of the rules and are prescribed entry services, prescribed exit services, prescribed common transmission services and prescribed transmission use of system services. The allocation principles generally are set out under clause 6A.23 of the rules.

3 The pricing method is set out in clause 6A.24 of the rules.

Without a robust inter-regional transmission charging mechanism, transmission network charges would not be effectively seen across region boundaries. As customers do not contribute to the costs of transmission assets in other regions that support electricity flows to their region, even if they benefit from those flows, the charges for the imported energy may not reflect the long-run marginal cost of serving loads in the importing region.

1.3 Solution proposed in the rule change request

The rule change request provides the following:[4]

- transmission businesses in each region would be required to levy a new charge - a load export charge - on transmission businesses in adjoining regions;
- the charge would reflect the flow of electricity from the region to adjoining regions;
- the level of the load export charge would reflect the costs incurred in the use of the transmission network in the region to conduct electricity to the adjoining region and therefore the charge should be calculated as if the relevant interconnection with the adjoining region was a load on the boundary of the region;
- a Co-ordinating Network Service Provider (CNSP) would be responsible for calculating both the charges to be levied on CNSPs in adjoining regions and the allocation of charges payable by transmission businesses in its own region;[5]
- TNSPs would calculate the prices to be applied in the upcoming financial year in accordance with a pricing method that has been approved by the Australian Energy Regulator (AER); and
- the total permitted revenue to be recovered by TNSPs in aggregate would not change - the rule proposed by the MCE would change the way revenues are collected.[6]

1.4 Relevant background

The development of provisions for inter-regional transmission charging have been ongoing and were first considered by the Commission as a part of the Review of Electricity Transmission Revenue and Pricing rules, which was initiated in 2005.[7] Potential solutions were considered further in the National Transmission Planner

4 MCE 2010, rule change request - Inter-regional Transmission Charging, February 2010, pp. 2-3.

5 There are existing provisions under the rules in clause 6A.29.1 for the appointment of CNSPs.

6 The Commission notes that the rule proposed by the MCE would also change the way in which costs are allocated by TNSPs.

7 An inter-regional transmission charge was first considered in the National Electricity Code Administrator's (NECA's) transmission and distribution pricing review in 1999.

(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.[8] 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 Review of Energy Market Frameworks in light of Climate Change Policies (Climate Change Review).[9]

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.[10] 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 and subsequently submitted this rule change request.[11]

1.5 Commencement of Rule making process

On 13 May 2010, the Commission published a notice under section 95 of the National Electricity Law (NEL) advising of its intention to commence the Rule making process and the first round of consultation in respect of the Rule Change Request. A consultation paper prepared by AEMC staff identifying specific issues or questions for consultation was also published with the rule change request. Submissions closed on 24 June 2010.

The Commission received eight submissions on the Rule Change Request as part of the first round of consultation. They are available on the AEMC website.[12]

The publication of the draft rule determination had been extended under section 107 of the NEL on two occasions. Firstly a notice under section 107 of the NEL was published on 13 May 2010 extending the time by four weeks to 30 September 2010, and secondly on 30 September 2010 extending the time by nine weeks to 2 December 2010.

1.6 First draft determination

On 2 December 2010, the Commission published the first draft rule determination (first draft rule determination) and first draft rule. In that determination, the first draft rule

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

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

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

11 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.

12 www.aemc.gov.au

generally maintained the intent of the proposal in the rule change request in terms of the composition of the load export charge and how it should be applied. It differed from the proposal in the rule change request in the following ways:

- the drafting of the load export charge provisions were amended for clarification;
- settlement residue auction proceeds were to be redistributed through the locational prescribed transmission use of system (TUOS)charge component under the draft rules (as opposed to through the non-locational prescribed TUOS charge);
- the transitional provisions under the rule change request were replaced with new transitional provisions. Under the draft rule, the transitional provisions require the AER to amend its pricing method guidelines and TNSPs to amend their pricing methodologies.

The Commission received 17 submissions on the first draft rule determination. Submissions in response to the draft rule determination argued against the proposed design of the load export charge (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.

1.7 Discussion paper

On 25 August 2011, the Commission published a Discussion Paper.[13] That paper, described several options to develop a uniform national inter-regional transmission charging regime, which the Commission sought comment on. The options are described in section 4. In line with the rule change request, the scope of those options did not extend into changing the approach to the current intra-regional transmission charging arrangements. To the extent that issues arose in relation to the intra-regional transmission charging arrangements, the Commission signalled its intention to address those through alternative processes such as the longer term Transmission Frameworks Review.

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13 AEMC, Discussion Paper, 25 August 2011

The Commission received 9 submissions on the Discussion Paper. These are summarised and responded to in Appendix A.

1.8 Modelling of Options

The Commission engaged ROLIB Pty Ltd to estimate the amount of inter-regional transmission charges that would have been levied between TNSPs over recent years if different options had been implemented. The results of the modelling have been published on the AEMC website.[14]

1.9 Consultation on second draft determination

The Commission invites submissions on this second draft determination, including a second draft rule, by 18 January 2013.

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

14 www.aemc.gov.au

2 Second draft determination

2.1 Commission's second draft determination

The Commission has made this second draft determination in relation to the rule proposed by the MCE.

The Commission has determined to make a proposed more preferable rule.[15]

The Commission's reasons for making this second draft determination are set out in section 3.

The second draft rule that the Commission proposes to be made is attached to and published with this second draft determination. The second draft rule is a more preferable rule. Its key features are described in section 13.

2.2 Commission's considerations

In assessing the rule change request the Commission considered:

- the Commission's powers under the NEL to make the Rule;
- the rule change request;
- the fact that there is no relevant MCE Statement of Policy Principles;[16]
- submissions received in response to the consultation paper, draft determination, discussion paper and modelling report; and
- the Commission's analysis as to the ways in which the proposed rule will or is likely to, contribute to the National Electricity Objective (NEO).

2.3 Commission's power to make the rule

The Commission is satisfied that the second draft rule falls within the subject matter about which the Commission may make rules. The second draft rule falls within the matters set out in section 34 of the NEL as it relates to section 34(1)(a)(iii) which sets out that the Commission may make rules with respect to the activities of persons (including registered participants) participating in the NEM or involved in the

15 Under section 91A of the NEL the AEMC may make a rule that is different (including materially different) from a market initiated proposed rule (a more preferable rule) if the AEMC is satisfied that having regard to the issue or issues that were raised by the market initiated proposed rule (to which the more preferable rule relates), the more preferable rule will or is likely to better contribute to the achievement of the National Electricity Objective.

16 Under section 33 of the National Electricity Law (NEL) the AEMC must have regard to any relevant MCE statement of policy principles in making a Rule.

operation of the national electricity system. Further, the second draft rule falls within the matters set out in schedule 1 to the NEL as it relates to:

- Item 16(1) - The regulation of prices charged or that may be charged by owners, controllers or operators of transmission systems for the provision by them of services that are the subject of a transmission determination; and

- Item 20 - The economic framework, mechanisms or methodologies to be applied or determined by the AER for the purpose of items 15 to 16 including (without limitation) the economic framework, mechanisms or methodologies to be applied or determined by the AER for the derivation of the revenue (whether maximum allowable revenue or otherwise) or prices to be applied by the AER in making a transmission determination.

The Commission considers that the second draft rule falls within these subject matters as the second draft rule relates to the setting and regulation of transmission pricing.

2.4 Rule making test

Under section 88(1) of the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NEO. This is the decision making framework that the Commission must apply.

The NEO is set out in section 7 of the NEL as follows:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of customers 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."

For this rule change request, the Commission considers that the relevant aspect of the NEO is promoting the efficient investment in, and use of, electricity services. [17]

The Commission is satisfied that the second draft rule will, or is likely to, contribute to the achievement of the NEO because the second draft rule promotes allocative efficiency and dynamic efficiency and hence would be in the long term interest of customers with respect to the price of supply of electricity. The second draft rule promotes efficiency in the following ways:

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17 Under section 88(2), for the purposes of section 88(1) the AEMC may give such weight to any aspect of the NEO as it considers appropriate in all the circumstances, having regard to any relevant MCE statement of policy principles. As noted in section 2.2, there is no relevant Statement of Policy Principles.

- allocative efficiency - the load export charge improves the cost-reflectivity of transmission charges by requiring customers that benefit from imported energy to contribute to the transmission costs of the exporting region. In the long term this would lead to more efficient use of the transmission system by existing and future customers, improving allocative efficiency; and;

- dynamic efficiency - the load export charge would promote dynamic efficiency by minimising any potential barrier to coordinated planning of investment in transmission network infrastructure by ensuring that all customers that may benefit from an investment would be able to contribute to its cost.

Under section 91(8) of the NEL the Commission may only make a Rule that has effect with respect to an adoptive jurisdiction if it is satisfied that the proposed rule is compatible with the proper performance of the Australian Energy Market Operator (AEMO)'s declared network functions. The second draft rule sets out a new process for TNSPs to allocate costs to a modified load export charge component. AEMO, in its capacity of a TNSP in Victoria, would be required to amend its pricing method in order to implement the second draft rule. The second draft rule does not impact on AEMO's obligations associated with planning or providing shared transmission services. For these reasons, the Commission considers the second draft rule is compatible with AEMO's declared network functions.

2.5 More preferable rule

Under section 91A of the NEL, the AEMC may make a rule that is different (including materially different) from a market initiated proposed rule (a more preferable rule) if the AEMC is satisfied that, having regard to the issues or issues that were raised by the market initiated proposed rule (to which the more preferable rule relates), the more preferable rule will or is likely to better contribute to the achievement of the NEO.

Having regard to the issues raised by the rule proposed in the rule change request, the Commission is satisfied that the second draft rule will, or is likely to, better contribute to the NEO as:

- it sends better price signals than the rule change proposal (section 6)

- it is calculated in a more consistent way across the NEM

- the regional beneficiary pays reflecting the benefit they derive (section 7)

- there is improved operational transparency (section 8)

2.6 Other requirements under the NEL

Under section 88B of the NEL, the AEMC must take into account the revenue and pricing principles in making a rule for, or with respect to, any matter or thing specified in items 15 to 24 and 25 to 26J in Schedule 1 of the NEL. The Commission has taken into account the revenue and pricing principles in making this second draft determination as the second draft rule relates to items 16(1) and 20 of Schedule 1 of the NEL. Some relevant aspects of the revenue and pricing principles relate to:

- providing a reasonable opportunity to service providers to recover efficient costs and ensuring that prices should allow for a return commensurate with the regulatory and commercial risks in providing the service; and
- having regard to the economic costs and risks of the potential for under and over utilisation of a transmission system with which a regulated network service provider provides direct control network services.

The Commission considers that the second draft rule is consistent with the revenue and pricing principles as it improves the cost reflectivity of the prices charged by TNSPs, encouraging more efficient use of the transmission network, without impacting the TNSPs' ability to recover efficient costs.

The second draft rule does not change the total amount of revenue recovered by TNSPs. However, it would result in an ongoing redistribution of transmission charges.

3 Commission's reasons

The Commission has analysed the rule change request and assessed the issues/propositions arising out of this rule change request. For the reasons set out below, the Commission has determined to make a more preferable rule.

3.1 Assessment of Options

Introduction of an IRTC

Current transmission charging arrangements, where customers do not contribute to the costs of transmission assets in other regions that support electricity flows to their region, do not fully reflect the interconnected nature of the NEM. Under the current arrangements, a region that experiences net-imports does not incur charges that fully reflects the costs of transporting that energy. The materiality of this issue is likely to increase in the future given that greater inter-regional flows are anticipated as a result of changes in the location of generation and for other reasons such as in response to climate change policies.

In its consideration of the rule change request the AEMC had to consider two separate but related questions.

- is the introduction of an inter-regional transmission charge (IRTC) going to better achieve the NEO, and
- if it does is there a implementable form of the IRTC that would better achieve the NEO?

The Commission considers that over time the introduction of an IRTC will better achieve the NEO. This is because an IRTC will:

- promote pricing efficiency by recognising the benefits from a transmission network that flow across state boundaries
- over time improve investment decision making by removing a small disincentive from TNSPs in pursuing expenditure that provides benefit to customers in neighbouring regions; and
- be more consistent with a regional beneficiary pays approach than the current arrangements.

Selection of a IRTC method

The Commission has developed and analysed several design options for inter-regional transmission charges. It has assessed these options in accordance with assessment framework described in section 5.

The Commission considers that the modified load export charge (MLEC) option is the preferred option, for the following reasons:

- it is likely to promote pricing efficiency at least as well as any of the other options, for the reasons set out in section 6;
- it is more consistent with regional beneficiary pays than a cost sharing approach and at least as consistent as the other cost reflective network pricing (CRNP) options and better than maintaining the status quo and cost sharing, for the reasons set out in section 7;
- while having significant issues in terms of transparency compared to cost sharing arrangements the MLEC is transparent as either the LEC or the NEM-wide CRNP based on the reasons set out in section 8;
- it promotes regulatory stability, for the reasons discussed in section 9; and
- the administrative cost of implementation and operation is the lowest of any of the options, for the reasons discussed in section 10

The Commission sees that there might be some potential benefits from introducing an alternative cost-sharing approach at some point in the future. However, the costs of designing and implementing these approaches would be disproportionate to the benefits of this rule change and, therefore, are not justified in the context this rule change request. Rather, they might be considered as part of a more fundamental NEM reform which also encompassed intra-regional transmission charging and, possibly, other aspects of the transmission frameworks.

3.2 Differences between proposed and second draft rule

Under the proposed rule, the LEC was proposed to be calculated based on adjustments to the locational and non-locational components of prescribed TUOS services and prescribed common services (prescribed TUOS services and prescribed common services are two categories of the four categories of prescribed transmission services). The adjustments would reflect the recovery of inter-regional charges levied by CNSPs in adjacent regions to the CNSP in the region that had the benefit of imports of energy.

Under the second draft rule, the LEC is modified (as the Modified Load Export Charge, MLEC) is proposed only to be calculated based upon adjustments to the locational component of prescribed TUOS services (as a more preferable rule).

To ensure consistent approach is taken for the estimation, recovery and billing for MLEC, the proposed rule (as necessary and consequential rules):

- requires the CNSP to undertake this estimation, recovery and billing for MLEC (and where a region only has one TNSP, that TNSP is to be regarded as the CNSP);

- requires the CNSP to adopt a standardised form of the CRNP methodology (the MLEC CRNP Methodology, in which all network costs are attributed, each interval of the previous regulatory year is considered and peak usage of each asset is used for the allocation of generation to load);
- excludes the effect of the MLEC from the 2% constraint on price variations for prescribed TUOS services – locational component;
- requires TNSPs who is a CNSP for a region to publish the calculated MLEC amounts by 15 March each year; and
- provides savings and transitional arrangements in which the AER is required to publish an amended pricing methodology guideline that takes into account the MLEC arrangements, and at a subsequent date, each of the TNSPs to prepare an amended pricing methodology that is subject to public consultation requirements).

3.3 Stakeholder views

The Commission's assessment has taken into consideration issues raised in stakeholder submissions to the rule change process. The issues raised in submissions are discussed in the following chapters and a detailed summary of the issues, and responses and comments from the Commission, are outlined in Appendix A.

3.4 Civil penalties

Chapter 6A contains no civil penalty provisions. The Commission does not propose to recommend to the MCE that any of the proposed amendments in the second draft rule be classified as civil penalty provisions as the second draft rule relates to the TNSPs' pricing provisions under Chapter 6A of the rules. The financial nature of the provisions under Chapter 6A provides incentives to ensure that TNSPs adhere to the requirements so that their costs may be efficiently recovered.

4 Options assessed

The Commission has consulted on five options to address the problems identified in the rule change request:

- status quo
- a load export charge;
- a modified load export charge
- cost-sharing; and
- a national electricity market -wide cost reflective network pricing.

Within each IRTC option, there are a number of design elements that can be varied, giving rise to multiple *sub-options* of each option.

The rule change request proposed a LEC.[18] The remaining three options were presented and discussed in the Discussion paper. Some submissions to that paper have proposed variants to these options, which have also been considered by the Commission.

4.1 Status quo

The status quo is a continuation of the existing arrangements for the recovery of costs associated with inter-regional transmission flows. So that recovery of these costs would be from customers within the TNSP region only.

4.2 Load export charge

Under this option, a transmission business in each region calculates and levies a LEC on TNSPs in adjoining regions. The charge is calculated as if the relevant interconnection with the importing network is a load on the boundary of the exporting region (ie, the load export point). It will reflect the costs of the assets in the exporting region which contribute to the transfer capability to export flows to the importing region.

In most respects the load export point is treated in the same way as all of the exporting transmission business's other load points. The CRNP is applied using the same methodologies as used to calculate the TNSP's intra-regional charge and TNSPs are required to submit pricing methodologies as part of the transmission determination process for every revenue reset to the AER.

The original LEC as proposed in the rule change request was to comprise the prescribed locational TUOS service charge, the prescribed non-locational TUOS service

18 MCE, Inter-regional transmission charging rule change proposal, 15 February 2010

charge and the prescribed common transmission service charge. However, the MLEC sub-option that is considered in this second draft determination only comprises the locational charge. This method is considered superior to the original LEC, for reasons discussed in sections 6 to 11.

4.3 Modified load export charge

Under the modified LEC option, each TNSP similarly calculates load export charges based on the LEC concepts described above. However, unlike in the LEC option, the calculation of LECs is undertaken separately from the calculation of locational transmission charges for intra-regional load points.

The TNSP undertakes one run of its CRNP method for intra-regional load points in which load export points are included, using the MLEC. For intra-regional transmission charging purposes the TNSP then undertakes a second run of the CRNP method, this time excluding load export points but including the IRTC caluclated under the first run. Locational TUOS charges at the other, intra-regional points are based on the second run.

There are many variants of the CRNP method permissible under the existing rules for calculating intra-regional locational TUOS charges and TNSPs have adopted different variants discussed further in section 13. However, under the MLEC option, all TNSPs are required to undertake the inter-regional pricing calculation using a common, specified variant.

The second draft rule specifies the CRNP variant to be used in the MLEC. The reasons for proposing that particular variant are discussed in section 13.

4.4 Cost sharing

The cost sharing option shares the costs of assets used for inter-regional flows between regions. In practice, all of the options do this. However, under the cost-sharing, the allocation is explicit and fixed. In the CRNP options, the allocation will vary from year to year, depending upon the timing and magnitude of inter-regional flows in the CRNP measurement intervals.

There are two steps in the cost sharing option:

- identifying assets for which costs are to be shared; and
- determining the cost allocation for those assets.

There are innumerable ways of undertaking these two steps - many of them presented and discussed in the Discussion Paper - and it would not be feasible to consider them all in detail in this second draft determination. Therefore, based on the analysis presented in the Discussion paper and on submissions to that paper, the Commission has examined a specific cost-sharing sub-option which it believes would be most likely (out of all of the cost-sharing sub-options) to be consistent with the NEO. Under this sub-option, which is based on a proposal made in a stakeholder submission[19]:

- only the cost of "new" assets (ie those developed and commissioned after the implementation of IRTC charging) are shared between regions;
- allocation of costs is based on the regulatory investment test - transmission (RIT-T) analysis, or an extension of that analysis, that was used to justify the development of the relevant assets;
- cost allocation is proportionate to the regional allocation of benefits arising from the development of the new assets, as estimated by that extended RIT-T analysis;
- the cost-allocation would be determined and agreed between relevant TNSPs ex ante: that is, before the new asset was developed; and
- the cost-allocation would then generally be fixed for the life of the asset, although in exceptional circumstances it may be possible to "re-open" and vary the cost-allocation at a later time.

Annually, the applicable annual revenues associated with each asset would be shared in accordance with the agreed allocation. IRTC would be calculated by each TNSP aggregating the shared revenue amounts across all relevant assets, netting off the amounts receivable from the amounts payable.

4.5 NEM-wide CRNP

This option is similar to the MLEC in that there are two runs of CRNP used in calculating transmission charges. As with the other CRNP methods the first run is used to calculate intra-regional transmission charges, based on current rules and methodologies, and the second run is used to calculate inter-regional transmission charges.

However, in the NEM-wide CRNP option, the second run uses a NEM-wide CRNP method, rather than a region-based CRNP with load export points. The NEM-wide CRNP run would allocate the cost of each shared network asset in the NEM between all customers in the NEM, across all regions in the NEM simultaneously, in accordance with the CRNP method. Similar to the MLEC option, and for similar reasons, the CRNP variant to be applied NEM-wide would be specified in the rules.

Since it is run just once, across all region simultaneously, the NEM-wide CRNP method must be operated by a single body. This body might be AEMO or another body established jointly by TNSPs for the purpose.

Inter-regional TUOS charges would be based on the aggregation of all costs that are allocated across region boundaries. For example, an asset in region A may have a cost

19 AGL Energy, Alinta Energy, International Power GDF-Suez, LYMMCo, Response to the AEMC's discussion paper, 23 September, p1

(ie annual revenue target) of $100,000, of which $70,000 is allocated to customers in region A, $20,000 to region B and $10,000 to region C. The intra-regional allocation is ignored. The $20,000 allocation contributes to the IRTC payable by TNSP in region B to the TNSP in region A. The $10,000 allocation contributes to the IRTC payable by TNSP in region C to the TNSP in region A.

As with the other CRNP-based options, IRTC are aggregated and netted, to determine the amounts payable bilaterally between TNSPs, and the net amount to be recovered through adjustment to intra- regional locational TUOS charges.

5 Commission's assessment approach

This chapter describes the assessment framework that the Commission has applied to assess the rule change request in accordance with the requirements set out in the NEL (and explained in chapter 2). The rule proposed by the MCE was assessed against the relevant counterfactual arrangements which, in this case, were the current provisions under the rules. It has also been assessed against the options described in section 4.

5.1 Options assessed

The following IRTC mechanisms have been assessed:

- the LEC method proposed in the rule change request
- a MLEC method
- a cost-sharing method, in particular the RIT-T approach suggested by AGL Energy, Alinta Energy, International Power GDF-Suez, LYMMCo (group of generators)
- an NEM-wide CRNP method

The design of each of these options is described in section 4.

5.2 Two-stage assessment process

To make the assessment process manageable, a two stage process has been applied. In the first stage, the preferred option is identified. In the second stage, the preferred sub-option is determined. The preferred sub-option is constrained to be a variant of the preferred option identified in the first stage.

5.3 Assessment criteria as outlined in the discussion paper

The AEMC published the following assessment criteria in its discussion paper.[20] The assessment criteria as outlined in that document are:

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

   (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.

Following feedback from stakeholders the AEMC has clarified some aspects of its assessment framework.

Cost-reflective price signals

In their submission, the group of generators have raised concerns about the objective of cost-reflectivity.[21] They argue that the cost of existing assets is sunk and so should not be reflected in TUOS prices; only new assets should be charged for. The Commission notes that existing assets are currently captured in the TNSPs intra-regional transmission charging method. It is important to recognise that the IRTC is being recovered through the intra-regional charge. To introduce a different method for an IRTC from the intra-regional method even if it is only to focus the IRTC on new assets is to distort the signal that is being produced by the combined pricing methodlogy.

The concept of "cost-reflective" does not just refer to variable (non-sunk) costs. Indeed, in the Commission's interpretation, cost-reflectivity is simply a means to an end. The end objective is simply "to promote efficient use of, and investment in, the transmission system". Transmission pricing affects transmission use directly, as customers respond to the prices. But it also affects transmission investment indirectly, since TNSPs take account of current and projected customer demand when planning transmission expansion.

The efficient transmission prices referred to in the assessment criteria simply mean prices that promote the NEO. Efficient transmission prices are discussed further in section 6.

"Causer or beneficiary pays" and regional beneficiary pays

The Victorian Department of Primary Industry (DPI) argues that, strictly speaking, a cross-subsidy only exists if the transmission charges in a region exceed the standalone cost: ie the cost of transmission if that region were isolated and not interconnected with other regions. The DPI indicates that this is unlikely to be the case.[22]

The Commission agrees that a cross subsidy only exists if the charges exceed the standalone cost, however, it is worth noting that the targeted removal of a cross-subsidy is simply a means to an end. The end objective is to remove a potential barrier to efficient inter-regional transmission development.

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20 AEMC, Inter-regional transmission charging rule change, p8

21 AGL Energy, Alinta Energy, International Power GDF-Suez, LYMMCo, Response to the AEMC's discussion paper, 23 September, p3

22 DPI, Response to the draft determination, 25 February 2012, p2

To reflect the broader meaning the Commission has therefore decided to express the relevant assessment criterion as follows: the TUOS pricing method should lead to a regional beneficiary pays outcome for investment, under which the allocation of costs between regions (ie between customers in aggregate in each region) is proportionate to the perceived regional allocation of benefits.

Cost-recovery

Under each of the options set out in section 4.2 to 4.5 each TNSP would apply the relevant method to calculate IRTC charges to apply to other TNSPs. These amounts would then be netted off, to calculate net charges payable. For example, if TNSP A calculate an IRTC for TNSP B of $10 million and TNSP B calculate an IRTC for TNSP A of $3 million, the net IRTC charge of $7 million would be payable by TNSP B to TNSP A.

Each TNSP would then aggregate its net IRTC charges across all other TNSPs. For example, suppose that, for TNSP B, $7 million is payable to TNSP A and $5 million receivable from TNSP C. So, the net aggregate IRTC to be recovered from customers in TNSP B's region is $2 million.

The net aggregate IRTC would be recoverable through an adjustment to the intra-regional revenue to be recovered.

For simplicity and comparability, it is assumed that the same approach is taken under each option. Although variants of this approach are possible, the Commission does not consider that these would affect its reasons for proposing the second draft rule.

The adjustment ensures that the aggregate revenue received by TNSPs – from its customers and from other TNSPs – is unaffected by the introduction of an IRTC, under all options.

This means that cost recovery would be equally achieved under all options under active consideration by the Commission. So while the Commission acknowledges the importance of cost recovery it does not provide a basis under which to distinguish between the options under consideration.

5.4 Assessment criteria

In order to clarify these issues, the AEMC is now describing its assessment criteria as:

- *efficient transmission pricing:* the development of transmission prices that promote efficient use of, and investment in, the transmission network;
- *regional beneficiary pays:* for transmission assets, the allocation of costs between regions (ie between customers in aggregate in each region) is proportionate to the perceived regional allocation of benefits;
- *regulatory stability:* the proposed rule change is consistent with the AEMC's approach of promoting NEM-wide consistency in regulatory frameworks in

order to encourage inter-regional trading. Also any departure from existing practice must be justified by the benefits it delivers;

- *administrative efficiency:* costs of implementation and operation are proportionate to expected benefits;
- *transparency:* transmission pricing methods and outcomes should be understandable and meaningful to customers and other stakeholders; and
- *impact on customers:* the impacts of the proposed rule change on customers are consistent with, and proportionate to, the issue that is being addressed.

Each of the options for a rule outlined in section 5.1 are considered each individual assessment criteria. The AEMC's considerations against each of these criteria are set out in sections 6 to 11 below.

6 Pricing efficiency

The LEC, MLEC and NEM-wide CRNP are all variations on CRNP. Therefore the question of pricing efficiency is considered at two levels. The first level considers the question: does the CRNP method deliver reasonable pricing efficiency compared to either the status quo or cost sharing?

If it does, then the second-level issue is to identify the form of CRNP that maximises net benefits consistent with the AEMC's assessment framework from an IRTC. However, if it does not, then alternative, cost-sharing approaches must be assessed.

6.1 Stakeholder views

Stakeholders raised two primary concerns about a CRNP based method:

- that it seeks to recover or "reallocate" sunk asset costs; and
- that it does this on the basis that reflects deemed usage.

Sunk asset costs

The group of generators considered that an IRTC should be based on the "purpose of the investment, and not on the essentially cost-free opportunistic use of transmission assets once they exist"[23] and there is "no justification in terms of the NEO in now undoing these past decisions [to construct interconnectors], by re-allocating these historical and sunk costs"[24]. Usage-based charging is not cost-reflective because "opportunistic usage of the network for purposes other than those originally envisaged has no material impact on [TNSP costs]"[25]

Similarly, the DPI Victoria considered that "there is no economic benefit in using long run marginal cost (LRMC) pricing linked to network usage for existing customers as the locational decision has been made and pricing usage above congestion costs will lead to a loss of allocative efficiency".

For these stakeholders, a cost sharing approach was preferred, under which cost allocation for a new asset would be based on the reasons for building that asset and would only subsequently change if those reasons could be said subsequently to have changed.

Reflects deemed usage

For those stakeholders who (at least implicitly) support CRNP as an efficient pricing method, concerns related to the inconsistent application of the CRNP method within or between regions.

23 Group of generators, Response to the AEMC's discussion paper, 23 September 2012, p2

24 Group of generators, Response to the AEMC's discussion paper, 23 September 2012, p2

25 Group of generators, Response to the AEMC's discussion paper, 23 September 2012, p7

AEMO noted that “inconsistencies (under the LEC option) in how key elements to transmission pricing were to be applied cast doubt on the validity of the pricing under that method.”

TruEnergy considered that NEM-wide CRNP “would be applied in a consistent manner nationally across the different jurisdictions “[26] Both AEMO and TruEnergy saw benefits from NEM-wide CRNP that, unlike other options, customers could be charged for transmission assets in non-adjoining regions (eg Queensland customers could be charged for their use of Victorian assets).

Some stakeholders[27]agreed that only locational TUOS charges should be applied across regions and applying non-locational charges inter-regionally could lead to less efficient prices.

6.2 Commission's analysis

For the Commission to accept that a non-CRNP method (ie, a different pricing method) is preferable (in principle) for an IRTC, it would need to be persuaded that the economic fundamentals of *inter*-regional transmission charging are sufficiently different from *intra*-regional transmission charging.

Although – in submissions – some stakeholders assert that the context is meaningfully different, the arguments that they make appear, to the Commission, to apply equally to inter-regional and intra-regional transmission. Specifically that:

- the costs of transmission assets should be sunk;
- assets should be built for a particular purpose and the CRNP method does not explicitly reflect that purpose; and
- applying a “LRMC” type price could lead to a reduction in short-run allocative efficiency.

The primary difference *between* the inter-regional and intra-regional context is that congestion prices are applied between regions but not within regions. However, this difference is not salient in the arguments made by stakeholders against CRNP and the Commission does not believe that this difference alone is sufficiently material to warrant using a different pricing method inter-regionally to that use intra-regionally.

The Commission recognises the in principle superiority of NEM-wide CRNP being able to recover asset costs from non-adjoining regions. However, it expects the materiality of this difference on pricing outcomes and efficiency to be small, and would more than likely be offset by the difficulties in administering NEM-wide CRNP (see section 10).

26 [TruEnergy, Response to the AEMC's discussion paper, 23 September 2011, p2]

27 Victorian Department of Primary Industries , Grid Australia, Tasmanian Office of Energy Planning and Conservation

6.3 Conclusions

Given the existing framework it has not been possible to identify a pricing method that is generally agreed to be materially more efficient than CRNP, at least for intra-regional pricing. Given that there is no relevant distinction between the inter-regional and intra-regional context, the Commission infers that this is also likely to be the case for inter-regional pricing. That is not to say that there is no prospect of improving upon the CRNP model, but rather the search for a replacement should be undertaken in a context – such as the Transmission Frameworks Review – in which reforms to frameworks for both intra-regional and inter-regional TUOS pricing can be considered.

On that basis, the Commission believes that introducing an IRTC charging based on a standard form of the CRNP will improve pricing efficiency with the NEM-wide CRNP showing the most significant benefit in this respect.

Retaining the status quo or introducing non-locational charges would not improve pricing efficiency.

7 Regional beneficiary pays

As discussed in section 5.4, regional beneficiary pays means that customers in a region contribute to the cost of a asset in proportion to the perceived benefits they receive from it. Under cost sharing options the sharing of costs is explicit; under CRNP options there will be some implicit sharing in costs, revealed by the increase in IRTC charges (compared to the counterfactual of no new inter-regional supporting assets) over the life of the new asset.

7.1 Stakeholder's views

Several submissions noted that the cost sharing approach could be the most effective way of allocating costs according to benefits.

AEMO noted that "if agreement could be reached, [cost sharing] could be the most accurate way of allocating interconnecting costs to the beneficiaries of the interconnector", but anticipates that reaching agreement "could be a challenge". [28]

The group of generators distinguished between an ex-ante benefit analysis (based on an analysis of the benefits of introducing the new asset) and an ex-post allocation (based on a usage analysis) offering that "ex-ante studies identify the purpose of an investment, while ex-post analysis can only address the less relevant question of the use to which it is put"[29]They proposed that the ex-ante benefit analysis should be based on – or similar to – the RIT-T analysis that the TNSP must undertake before commencing investment. The cost allocation would be locked to that ex ante benefit analysis, except under specified circumstances where the costs might be re-allocated.

There was no explicit commentary on whether the CRNP method was intrinsically compatible with regional beneficiary pays. However, some stakeholders noted that some applications of the CRNP method could lead to anomalies. AEMO noted that "differing valuation and apportionment methodologies between those regions, will cause customers to face unclear and inconsistent locational pricing signals as each region charges load export charges based on differing apportionment methods from their neighbours"

7.2 Commission's analysis

Cost-sharing Options

The cost sharing option explicitly allocates the costs of a inter-regional asset between regions. However, this only achieves a regional beneficiary pays if the cost sharing method is such that the allocation outcomes match perceived benefits. That is unlikely to be the case for those generic methods described in the Discussion paper. On the other hand, allocations based on an explicit ex-ante benefits analysis (as proposed by

28 AEMO, Response to the AEMC's discussion paper p2

29 Group of generators, Response to the AEMC's discussion paper. 23 September 2012, p3.

the group of generators) would better reflect the allocation of benefits at this point in time.

The Commission notes that in the context of the IRTC the benefits produced by an ex ante-benefits analysis based on the RIT-T would be significantly reduced. This is because the IRTC would reflect the ex-ante determination of value but the much larger intra-regional charge would be based on the CRNP. As would be expected from two very different methodologies, in some circumstances they would conflict thereby reducing the shorter term price signal produced by the CRNP methodology as well as the long term price signal produced by the ex ante benefits analysis.

A dynamic cost sharing allocation (eg updated annually) based on a full benefits analysis would be administratively complex and possibly impractical if it required renewed agreement between TNSPs.

CRNP Options

The Commission has not modelled the CRNP options in sufficient detail to verify whether, for a new asset, incremental regional charges reflect regional benefits. However, given the customer-pays design of CRNP, the Commission is of the view that this will be the case. For example, if imports into region A increase as a result of a new asset built in region B, the CRNP method will identify that customers associated with the load export point are using the new asset and will therefore allocate some of the costs to that region. On the other hand, if the new asset simply increases exports from region A, CRNP will allocate the asset costs entirely to region B customers.

The modelling of the different CRNP methods suggests quite different outcomes dependent on the approach modelled (discussed further in section 8.2).

7.3 Conclusions

The cost-sharing approach proposed by the group of generators satisfies the regional beneficiary pays criterion in relation to expected benefits. However, if outturn benefits vary from expected – but the cost allocation is fixed – the regional beneficiary pays criterion may not be satisfied at a later date. Making the cost allocation dynamic whether through a regular recalculation or in response to “re-opener” criteria as proposed by the group of generators would address this flaw, but at the expense of significant additional administrative complexity.

Application of CRNP methods for calculating IRTC are likely to satisfy the regional beneficiary pays criterion. However, no quantitative modelling has been undertaken to verify this and it is not known whether one CRNP option is superior to the others in this respect.

As noted above the status quo has significant issues in that it in no way apportions costs inter-regionally. Therefore, if the beneficiary is in a different region there is no reflection of that fact in charges.

8 Transparency

The Commission considers that transparency (of TUOS pricing) is an important assessment criterion. There are three, potentially conflicting, aspects of transparency:

- transparency of pricing method: the method should be easy to understand conceptually;
- transparency of pricing operations: discretion for the TNSP (or other pricing institution) under the pricing method should be limited and applied consistently and openly;
- transparency of pricing outcome: outcomes should be coherent, reasonably stable over time, and consistent with a non-expert's understanding of the pricing approach

Transparency makes future prices broadly predictable, which allows long-term decision making (eg choice of location) by customers in response to those anticipated prices. Conversely, prices that are not transparent will simply not be included in the customer's decision making. Each of these forms of transparency are considered in the Commission's analysis below.

The CRNP method – as applied intra-regionally at present – is highly complex. There is limited information available in the public domain on its operation and the differences in approaches taken by TNSPs from region to region. Given the IRTC will result in a charge being recovered through the intra-regional transmission charging method. The relevant measure for an IRTC is the extent to which transparency increases or reduces as a result of each option.

8.1 Stakeholder's views

Stakeholders were concerned that methodological inconsistencies across TNSP pricing methodologies would lead to a loss of transparency.

In the LEC option, inconsistency arises in differences in inter-regional CRNP methods between regions. TruEnergy noted: "The original LEC was simpler to implement but the inconsistencies in how key elements to transmission pricing were to be applied cast doubt on the validity of the pricing under that method".[30] Similarly, AEMO noted: "differing valuation and apportionment methodologies between those regions, will cause customers to face unclear and inconsistent locational pricing signals as each region charges load export charges based on differing apportionment methods from their neighbours".[31]

30 TruEnergy, Response to the AEMC's discussion paper, 23 September

31 AEMO, Response to the AEMC's discussion paper, 23 September 2012, p2

The MLEC option, on the other hand, creates inconsistency between inter-regional and intra-regional methods within a region. The Tasmanian Office of Energy Planning and Conservation (OEPC) noted: "Customers / stakeholders may find differences in method between intra and inter regional charging confusing, adding to an already complex system of calculating prescribed transmission charges."[32]

The group of generators argued that a cost-sharing approach is more transparent because "it is based on the transmission planning process which is already significantly transparent; it adds a further level of transparency in requiring an independent review; it involves a small number of individually significant decisions, and is thus inherently more open to scrutiny than multiple small decisions, especially if these frequent decisions were to involve complex calculations as the other options proposed would require."[33]

8.2 Commission's analysis

Transparency issues are quite different between the CRNP and cost-sharing methods and are considered separately.

CRNP Methods

As stakeholders commented, inconsistencies inevitablly arise in any CRNP method: either between regions, or between intra-regional and inter-regional charges within a region. That inconsistency causes some loss of transparency in pricing operations and pricing outcomes, because the outcomes from the different methods are not comparable.

Transparency of pricing operation and outcome

The most significant outcome from the application of an IRTC will be the net payment from one TNSP to a neighbouring TNSP. The net payment from TNSP A to TNSP B is the difference between:

- the IRTC calculated by TNSP B as payable by TNSP A; and
- the IRTC calculated by TNSP A as payable by TNSP B.

If these two components are calculated using different CRNP methods, then part of the net payment is as a result of the differences in the methods rather than the underlying fundamentals. For example, the modelling results for the IRTC between NSW and Victoria are summarised in Table 8.1.

32 OEPC, Response to the AEMC's discussion paper, 23 September 2012, p5

33 group of generators, Response to the AEMC's discussion paper. 23 September 2012, P8

Table 8.1 IRTC reflecting differences in methods($m annual average)

Method	NSW pays VIC gross	Vic pays NSW gross	NSW Pays Vic Net
MLEC using 365C	32	25	+7
MLEC using 10E	0	4	-4
NEM-wide CRNP	38	28	+10
LEC (mixed)	0	25	-25

The 365 day interval capacity element method is currently used intra-regionally in NSW and the 10 day peak interval energy element method intra-regionally in Victoria. These sub options are discussed further in section 12.

The NEM-wide CRNP method, gives a range of results, the methods are broadly internally consistent, in that they estimate IRTC charges being similar from NSW to Vic as they are from Vic to NSW, giving rise to a relatively small net IRTC in each case. This small net IRTC is consistent with the flows from one region to the other. The method utilised to produce these results is still noticeably opaque to the customer given the complexity of the CRNP approach.

The 10 day peak and the LEC both gives results that appear to be counter intuitive to what would expected to be seen based on net load flows from Victoria to NSW. These methods are similar in calculation to the NEM-wide CRNP and the 365 day interval approaches in that the complexity results in a lower operational transparency. However, the outcome is inconsistent with expectations making for a lack of outcome transparency for these approaches. This does not necessarily mean that a result that shows a net IRTC being paid by a net export is incorrect, as the cost of the assets providing those flows is a relevant factor. However, if inverse flows and costs are the correct outcome there is a need for additional transparency of operation to allow customers to satisfy themselves there is a basis for that outcome.

On the other hand, if the IRTC are calculated using similar CRNP methods, the net payment should reflect fundamentals, and vary only as these fundamentals change.

Cost-sharing Method

The RIT-T based cost-sharing approach has two main components:

- identify new “inter-regional” assets that are to be developed, having passed a RIT-T test; and
- allocate the costs of the assets between regions, based on the expected regional distribution of benefits provided by those assets.

The details of these component methods have not been developed. Firstly, it is not clear how intrinsically transparent these methods will be. Secondly, it is not clear as to what extent these methods will be consistent between regions.

Notwithstanding this lack of detail, the Commission acknowledges that, to the extent these components are based on RIT-T methods and processes, they are likely to share the RIT-T's transparent qualities. In that respect, they are likely to be intrinsically more transparent than CRNP methods.

Because cost allocation would be applied on a project basis, the netting off issue is less significant. Net IRTCs payable will still depend on the net effect of the cost-sharing of all inter-regional projects for either side of the regional boundary. But the net payment would not be expected to reflect current market and transmission fundamentals in the same way as the CRNP methods.

Regional inconsistency may be significant when there is a single inter-regional project that crosses the regional boundary and so involves investment by two TNSPs. In this case, it would be important that the cost-allocation was done on a project-wide basis – using a single method agreed upon between the two TNSPs – to strengthen transparency.

Thus, cost-sharing will be relatively transparent at the time that the cost allocation is determined. However, if that cost allocation is then fixed for an extended period that transparency will erode over time. For example, a customer in 2035 may be paying an IRTC based (to some extent) on a cost allocation that was agreed and fixed in 2015. Clearly, that customer is unlikely to have any knowledge or understanding of that historical cost allocation decision and may question its relevance to present-day pricing.

A similar situation could arise if a customer signed a long term contract in 2015: eg a connection agreement with a term of 30 years. But the two contexts are fundamentally different. In the case of IRTC, there was no agreement from customers, in 2015, to lock themselves into long-term cost sharing. Rather, the TNSP has built a long-lived asset on the expectation that the asset will continue to be useful in providing transmission services to customers over the life of the asset.

8.3 Conclusions

It is important for transparency that consistent methods are applied by all TNSPs in calculating gross IRTC. If there is inconsistency between methods, then the net IRTC may simply reflect methodological differences rather than fundamentals and be practically impossible for stakeholders to understand and predict. Therefore, in this respect, the LEC option is inferior to the other CRNP options.

The cost-sharing option provides the most transparency of all the options at the time that the cost allocation decision is made. However, because the cost allocation is then generally fixed for the life of the assets (ie for several decades) the historical decision will become less transparent and irrelevant for future customers. Thus, it is not transparent in a meaningful sense.

9 Regulatory stability

Regulatory stability requires that proposed rule changes are broadly consistent with an underlying regulatory principle. In this case, the relevant principle is one promoting NEM-wide consistency of regulatory frameworks, particularly those relating to transmission.

9.1 Stakeholder's views

Grid Australia was concerned to ensure that any rule change made would not prejudice future reform arising out of the Transmission Frameworks Review (TFR), noting that: "introducing a relatively simple arrangement now would not necessarily interfere with further changes required as a result of the TFR. However, more complex far reaching options may create issues for future subsequent changes."[34]

Submissions on the Discussion Paper were made prior to 23 September 2012, which corresponded to a relatively early stage in the TFR. Given that the TFR has now considered the issue of inter-regional transmission pricing more fully, stakeholders' submissions on this second draft determination may focus more on this issue of regulatory stability.

9.2 Commission Analysis

The cost sharing approaches are based on identifying "inter-regional assets", as distinct from "intra-regional assets" and developing and applying a different pricing method to those assets. Dividing the transmission network into "intra-regional" and "inter-regional" components appears to be creating new distinctions – where none currently exist – rather than removing existing ones. It is therefore inconsistent with regulatory stability.

The CRNP methods, on the other hand, both extend the application of CRNP across regional boundaries. MLEC and NEM-wide CRNP also bring increased consistency to the CRNP approaches taken by TNSPs. However, the LEC might be considered to entrench existing inconsistency in CRNP methods between regions.

The NEM-wide CRNP implements a NEM-wide transmission pricing method which aligns with a Commission proposal in the second interim report of the TFR, albeit that this method only applies to inter-regional, and not intra-regional pricing.

9.3 Conclusions

The MLEC approach is an incremental improvement on existing arrangements within the scope set by the MCE rule change. The arrangements as proposed by the Commission are such that they are robust should they remain in place for an extended

34 GridAustralia, Response to the AEMC's discussion paper, 23 September 2011, p8

period of time but would allow for more significant reforms to TNSP pricing to be implemented in their place should that be necessary.

10 Administrative Efficiency

As discussed in section 6, the efficiency benefits associated with this rule change are likely to be modest. It is critical that administrative costs, especially implementation costs, are low to ensure that the rule change delivers net benefits in accordance with the NEO.

10.1 Stakeholder's views

For CRNP options, stakeholders generally expected administrative costs to be proportionate to the difference between inter-regional methods and existing intra-regional methods. Grid Australia noted that “new options appear to be administratively complex to implement, as they represent a shift away from the existing method TNSPs use for their intra-regional charging”[35]. Similarly, OEPC anticipated that “administrative costs will be higher for those jurisdictions that apply a different method in calculating intra-regional charges to that used for calculating the nationally consistent inter-regional.”[36]

Grid Australia predicted that administrative costs could be minimised by being pragmatic (in the MLEC) about requiring uniformity only to address “major” differences in intra-regional methods.

In relation to cost sharing, the group of generators acknowledged a risk that “desirable projects may be delayed by a stalemate over cost allocation”[37] and proposed that cost allocation should be verified by an “independent authority” to mitigate this risk, acknowledging that this might require some “additional administrative effort”[38]. However, agreement on cost sharing (under the group of generators’ proposed approach) would typically only be required once during the life of an asset and only some “small additional work” would be needed – over and above the normal RIT-T analysis – to identify the allocation of benefits between regions.

AEMO noted that agreement between TNSPs to share transmission costs across regional boundaries has “been applied only once in the NEM”.[39]

Grid Australia considered that implementation of an NEM-wide CRNP would require “a consistent national valuation and cost allocation model” and existing “inconsistencies between replacement cost models” therefore presented a” fundamental obstacle”[40].

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35 Grid Australia, response to the AEMC's discussion paper, 23 September 2011

36 (OEPC, Response to the AEMC's discussion paper, 23 September 2012, P4)

37 Group of generators, Response to the AEMC's discussion paper, 23 September 2012, p4

38 Group of generators, Response to the AEMC's discussion paper. 23 September 2012, p8

39 AEMO, Response to AEMC's discussion paper, 23 September 2011

40 Grid Australia, Response to the AEMC's discussion paper

10.2 Commission's analysis

Implementation Costs

Implementation costs of LEC and MLEC methods are expected to be modest. This is because these methods require only minor change to existing intra-regional pricing processes in:

- including connection points within the CRNP cost allocation process for the purposes of calculating LEC or MLEC; and
- (for MLEC) by the CNSP applying a standard form of CRNP for the purposes of calculating MLEC (Some TNSPs use a modified form of the CRNP).

The variant of CRNP to be used in the MLEC has been selected with a view to minimising these implementation costs. This is discussed further in section 12.

The NEM-wide CRNP option requires that the pricing institution establishes a CRNP process that covers the entire NEM. In principle, this should not be too complex, since NEM-wide data exists in a form that can be fed into TPRICE.[41] . The modelling consultant engaged by the AEMC to estimate customer impacts see section 11 found that establishing an NEM-wide CRNP method was not as straightforward as expected, and a number of issues arose that would require resolution in an NEM-wide CRNP implementation. These included:

- data errors and inconsistencies within a region leading to anomalous interconnector flows. These were corrected in the modelling by introducing fictitious generators on region boundaries; and
- outcomes were sensitive to assumptions on generator source impedances. In the CRNP method this affects how generation is matched to load for the purposes of deeming asset usage.

These issues would need to be resolved in any implementation of a NEM-wide CRNP.

The Commission agrees with Grid Australia that a NEM-wide CRNP requires consistent asset cost allocation between regions, otherwise IRTC outcomes could reflect these inconsistencies rather than market and cost fundamentals. This is a similar concern to that relating to LEC inconsistencies, discussed in section 8. Although establishing consistent cost allocation may be a worthwhile objective in its own right, it may be very costly to achieve.

Further, the implementation of a NEM-wide CRNP requires the identification of a party to undertake the modelling and make decisions where conflicting data arises. Currently, there is no organisation with both the requisite skill base to undertake the necessary modelling and sufficient independence from the results of the modelling.

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41 TPRICE is is the computer program used by TNSPs in calculating their prices

Thus, the NEM-wide CRNP implementation costs are expected to be substantially greater than the other CRNP options.

Implementation costs of a cost-sharing approach are likely to be much higher. Mechanisms or processes would need to be designed and implemented to:

- categorically identify any new “inter-regional assets” to which a cost-sharing approach would apply;
- allocate the costs of these assets, using a formulaic or “beneficiary pays” approach

Although existing RIT-T methods calculate expected benefits, these are not easily attributable to particular regions. Developing an attribution method is likely to be difficult and contentious.

Operational Costs

The cost-sharing and CRNP options have fundamentally different operational costs. Cost-sharing only takes place when new interconnector assets are developed. This is likely to occur only rarely. However, precisely because the cost-sharing process is not routine, the costs of determining the IRTC when it is required are likely to be high. Furthermore, the very fact that TNSPs only incur these costs when an inter-regional asset is developed may discourage TNSPs from undertaking such an investment: which is precisely the opposite effect to what the rule change request seeks to achieve.

CRNP methods, on the other hand, would be undertaken annually, irrespective of transmission investment. With annual repetition, any administrative difficulties would be expected to be quickly resolved and so ongoing annual costs will be low.

The MLEC and NEM-wide CRNP methods are intrinsically more administratively onerous than the LEC method, because they involve a second, inter-regional run of the CRNP method. However, for MLEC, the administrative cost of this inter-regional run is not expected to be onerous, since it will use essentially the same data as the intra-regional run, with a few settings changes on the TPRICE program to reflect (for some regions) the difference in the method used.

For NEM-wide CRNP, the costs may be significantly higher. On the other hand, the operation is only carried out once, by a single institution. In the other CRNP methods, each TNSP carries out the IRTC calculation in concurrently.

10.3 Conclusions

Administrative costs for the LEC and MLEC methods are anticipated to be very low. Whilst the MLEC costs depend upon the particular sub-option that is implemented, the second draft rule specifies a sub-option that minimises expected administrative costs discussed in section 13

The operational NEM-wide CRNP costs might be similar to or even lower than the other CRNP options. However, implementation issues are so significant in the current NEM framework that overcoming them may be greater than benefits to be derived from the introduction of an IRTC.

Cost-sharing is likely to have high implementation and operational costs, although operational costs are only occurred when a new inter-regional asset is developed, which may be relatively infrequent. On the other hand, the prospect of incurring these costs might actually deter efficient inter-regional investment.

11 Impact on customers

11.1 Stakeholder's views

The Major Energy Users Ltd (MEU) noted concerns that variability in costs is a major concern in regions that have a large degree of weather risk. They also express concerns that prices which show significant variability year on year will reduce the locational signals to generators and customers.[42]

The OEPC believe some form of smoothing mechanism needs to be introduced such that charges do not vary significantly and unpredictably from year to year.[43]

11.2 Commission's analysis

The Commission engaged ROLIB Pty Ltd to estimate the IRTC under the CRNP-based options (ROLIB Pty Ltd report). The ROLIB Pty Ltd report is available on the AEMC's website. The cost to customers under a cost sharing method would be directly related to the allocation method selected.

The tables below present estimated average IRTCs for the 2009-12 period (had IRTC been implemented for those years) using the three CRNP-based options:

- LEC: contained in the rule change request
- MLEC: the preferred method, described in section 4.3
- NEM-wide CRNP method:

Because of the lack of pricing efficiency that would result from the inclusion of postage stamp components in the pricing calculation only locational IRTC charges are modelled.

The LEC impacts are derived by applying, as accurately as the scope of the modelling allows, the CRNP method that each TNSP applies currently in its own region[44]. That is:

- *historical study period:* in Victoria, the 10E region system peak method is applied and in other regions the 365C method is applied
- *CRNP method:* in all regions the standard (as opposed to modified) CRNP method is applied[45]:

42 MEU, Response to the AEMC's discussion paper, 23 September 2012, p4

43 OEPC, Response to the AEMC's discussion paper, 23 September 2012, p2

44 Variants to the CRNP methodology are explained in more detail in section 4

45 Although SA and Tasmania use modifeid CRNP, the estimated outcomes for modified CRNP are not materially different to CRNP. Tis is because the modified CRNP method was only applied to radial lines.

- *allocated assets:* in all regions, the costs of all assets are allocated;

Table 11.1 Estimated IRTC for LEC method

		Region paying IRTC					
		Tas	SA	Vic	NSW	QLD	Gross R’c’d
Region Receiving IRTC	Tas		0	5	0	0	5
	SA	0		20	0	0	20
	Vic	0	22		0	0	22
	NSW	0	0	25		8	33
	QLD	0	0	0	17		17
Gross Paid			0	22	50	18	8
Net Paid			-5	2	28	-15	-9
Per cent net Paid		-9.1%	1.7%	11.6%	-4.9%	-4.0%	
Per cent net SD		2.0%	3.3%	1.2%	0.8%	0.2%	

Table 11.2 Estimated IRTC for MLEC method

		Region paying IRTC					
		Tas	SA	Vic	NSW	QLD	Gross R’c’d
Region Receiving IRTC	Tas		0	5	0	0	5
	SA	0		20	0	0	20
	Vic	1	33		32	0	65
	NSW	0	0	25		8	33
	QLD	0	0	0	17		17
Gross Paid		1	33	50	49	8	140
Net Paid		-5	13	-16	17	-9	-9
Per cent net Paid		-7.9%	1.7%	11.6%	-4.9%	-4.0%	
Per cent net SD		1.8%	1.2%	1.1%	0.3%	0.2%	

Table 11.3 Estimated IRTC for NEM-wide CRNP method

		Region paying IRTC					
		Tas	SA	Vic	NSW	QLD	Gross R'c'd
Region Receiving IRTC	Tas		1	8	0	0	9
	SA	1		24	4	0	29
	Vic	1	35		38	12	86
	NSW	1	3	28		18	50
	QLD	0	0	1	24		25
Gross Paid		3	39	60	66	31	
Net Paid		-6	10	-26	16	6	
Per cent net Paid		-10.5%	9.4%	-10.6%	5.0%	2.4%	
Per cent net SD		3.4%	3.1%	1.4%	2.0%	2.3%	

Table 11.4 Summary of per cent net TUOS impacts

	Tas	SA	Vic	NSW	QLD
LEC	-9.1%	1.7%	11.6%	-4.9%	-4.0%
MLEC	-7.9%	12.0%	-6.5%	5.3%	-4.0%
NEM-wide CRNP	-10.5%	9.4%	-10.6%	5.0%	2.4%

Table 11.5 Summary of per cent net TUOS standard deviations

	Tas	SA	Vic	NSW	QLD
LEC	2.0%	3.3%	1.2%	0.8%	0.2%
MLEC	1.8%	1.2%	1.1%	0.3%	0.2%
NEM-wide CRNP	3.4%	3.1%	1.4%	2.0%	2.3%

Given that only three years have been modelled, the estimated standard deviations are not statistically significant and should be treated with some caution.

The tables show that the outcomes are broadly similar under MLEC and NEM-wide CRNP: Queensland has the biggest difference with 6 per cent. However, outcomes under LEC are markedly different, with Victoria going from paying 12 per cent under LEC to receiving 11 per cent under NEM-wide CRNP. That difference arises because of the different CRNP method used in Victoria in the LEC option.

MLEC gives the most stable outcomes, with variations of around 2 per cent or less. LEC and NEM-wide CRNP give variations of more than 3 per cent in some cases.

Under normal operation, average intra-regional TUOS prices vary in line with average revenue (capped revenue divided by demand) which, taking into account variations in Settlement Residue Auction (SRA)proceeds, may cause variations of up to 10 per cent per year. Around this average, variations of up to 2 per cent are permitted. Thus, a one-off impact of 12 per cent, followed by maximum year-on-year variations of 4 per cent say (2 standard deviations) is broadly in line with existing TUOS variations. Therefore, the Commission does not consider it necessary to phase in the new charging regime over several years nor to introduce a smoothing mechanism across years.

11.3 Conclusions

Customer impacts appear to be proportionate to the objective of improved pricing efficiency. The price change that would likely occur on the introduction of an IRTC is likely to be similar in magnitude to typical annual price variations that customers face currently, so no phasing-in of the IRTC price is required in order to reduce volatility.

NEM-wide CRNP prices appear to vary rather more from year to year than the other CRNP options. It is not clear whether they are better tracking changes in the fundamentals or volatility is inherent in the approach.

The Commission concludes that all of the CRNP options are satisfactory in their impact on customers. The impact of the cost sharing option has not been estimated.

12 Conclusions on IRTC method

As noted in section 2.5 the Commission is of the view that the MLEC method is the most suitable way to implement an interrgional transmission charge as it:

- sends better price signals than the current arrangements as a result of improved operational transparency and stability, although noting that the NEM wide CRNP would send superior price signals but provides a similar level of transparency (section 6 and section 8)
- is calculated in a more consistent way across the NEM
- the regional beneficiary pays reflecting the benefit they derive at the time of their use in comparison to the LEC or Generator's cost sharing approach. Although noting it does not reflect this as well as the NEM wide CRNP (section 7)
- has relatively minor implementation costs compared to either the cost sharing and substantially less than the NEM-wide CRNP method (section 10)
- Is a method consistent with that already used in transmission and represents and increment improvement consistent with the current regulatory approach (section 9)
- Produces stable outcomes for customers compared with the LEC and NEM-wide CRNP approaches (section 11).

So on balance the MLEC is the method that overall best meets the NEO.

13 Preferred sub-options

As described in section 5.2 the Commission has adopted a two stage assessment process:

- in the first stage, the preferred option is identified; and
- in the second stage, the preferred sub-option for that preferred option is chosen.

The same assessment criteria as were used to determine the appropriate method are also used for assessing sub-options. The assessment criteria are set out in section 5.3 but for convenience they are reproduced below.

There were a number of sub-options available based on the methodologies utilised by the TNSPs in different regions. These are discussed in more detail in section 13.2 to 13.5.

Transmission pricing sub-options

In calculating transmission pricing the TNSPs split TUOS charges into locational, non locational and common network services. Non-locational charges and common network services are recovered on a postage stamp basis. Locational components are recovered on a CRNP basis. Calculating CRNP involves a number of choices these are set out in Table 13.1.

Table 13.1 Options for construction of a MLEC

Aspect of CRNP Method	*Preferred sub-option*	*Alternative sub-option*
Measurement interval selection	Usage across all half hours ("365 day")	Usage across 10 "peak" half-hours ("10 peak")
Element usage	Capacity (customer peak on element)	Energy (average consumption on element)
CRNP method	Standard CRNP	Modified CRNP
IRTC recovery method	Locational	Non-locational
Assets Included in Calculation	All assets	New assets only

13.1 Assessment criteria

The assessment criteria used by the AEMC in assessing the sub-options are:

- *efficient transmission pricing:* the development of transmission prices that promote efficient use of, and investment in, the transmission network;

- *regional beneficiary pays:* for new transmission assets, the allocation of costs between regions (ie between customers in aggregate in each region) is proportionate to the perceived regional allocation of benefits;
- *regulatory stability:* the proposed rule change is consistent with the AEMC's strategy of promoting NEM-wide consistency in regulatory frameworks in order to encourage inter-regional trading;
- *administrative efficiency:* costs of implementation and operation are proportionate to expected benefits;
- *transparency:* transmission pricing methods and outcomes should be understandable and meaningful to customers and other stakeholders; and
- *impact on customers:* the impacts of the proposed rule change on customers on are consistent with, and proportionate to, the issue that is being addressed.

The following sections apply the assessment criteria against the options for consideration. They focus on those assessment factors where there is a difference between the two options utilised by TNSPs.

13.2 Measurement interval selection

In most regions all half hourly intervals were included in the calculation of intra-regional transmission charges. This method is referred to as the "365 day" method after the number of days that are included in the calculation of charge. In Victoria, AEMO utilises a "10 peak day method". That is, AEMO identifies ten peak periods occurring on separate days and utilises those periods in its customer charging method. For the modelling report by ROLIB Pty Ltd the AEMC requested modelling of the 365 day method as well as three separate ways of identifying the 10 peak days. These were the region peak, the same as utilised by AEMO, the peak exports on the interconnector and the 10 NEM wide peak days.

The Commission has selected the 365 day method as it is of the view that this method produces more efficient transmission pricing. It does this by producing greater stability in pricing across years. The Commission considers that this stability will result in clearer signals being sent to customers as to the likely effect of their behaviour.

The 10 day peak methods were subject to wider variability than the 365 day method due to greater variability in the peak than in the average consumption. As customers' behaviour leads to the creation of the peak each customer's contribution towards the peak should normally be reflected in the prices they pay in order to create the correct incentives for the customer. However, as the IRTC is recovered through the intra-regional charges this distorts the pricing signal so that the higher price is not necessarily paid by customer who contribute to the peak usage.

13.3 Element usage

In order to allocate costs to customers it is necessary to determine their use of the network. In the NEM two different approaches have been adopted, these are:

- the energy approach; or
- the capacity approach.

An example of these two approaches is set out in Box 13.1:

Box 13.1: Simplified example of element usage

In a two customer, two period scenario the energy usage is set out in Table 13.2.

Table 13.2 Customer usage for example

Customer	Period one	Period two
Customer A	20 MWh	60 MWh
Customer B	50 MWh	40 MWh

Energy approach

Under the energy approach the total usage for customer A is summed together 20 MWh + 60 MWh = 80 MWh. The same is done for customer B, 50 MWh + 40 MWh = 90 MWh. Then the proportion of total usage across the time period is determined for each customer by summing the total usage together (80MWh + 90MWh = 170 MWh) and then dividing each customers use into that number. So for customer A their use of this element is 80 MWh / 170 MWh = 47 per cent for customer B it is 90 MWh / 170 MWh = 53 per cent.

Capacity approach

Under the capacity approach the customers peak usage for the measurement intervals is identified. For customer A it is 60 MW (usage in period two is higher than in period one)and for customer B it is 50 MW (usage in period one was higher than usage in period two). These are summed together 60 MW + 50 MW = 110 MW. The proportion of the customers' peaks is determined. For customer A it is 60 MW / 110 MW = 55 per cent and for customer B it is 50 MW / 110 MW = 45 per cent.

The energy element utilisation method reflects the average use by different customers of the transmission network element across the measurement intervals. It does this by measuring each customers use of the network element for each period in the measurement period then summing them together and dividing by the total consumption.

As can be seen in the example in Box 13.1: the capacity element utilisation looks at the peak of each customer's use of the transmission network element. Noting that different customers will have peaks at different times, this does not mean double recovery as the peaks are summed together and the usage is determined as each customer's proportion of that total.

Most TNSPs use the capacity element method, with the exception being Victoria where the energy method is used. TNSPs augment their network by expanding the capacity of elements reflecting their peak usage. Where the 365 day method of interval selection has been adopted then a capacity (peak) approach will more closely match the costs of the TNSPs. This, over time, will lead to greater price efficiency and will better align costs and benefits.

13.4 Relevant network assets

The AEMC requested modelling of two alternate approaches reflecting feedback from stakeholders. In their response to the discussion paper the National Generators Forum (NGF) suggested that the IRTC should not apply to existing assets. So the AEMC requested the modelling cover both new assets only and existing assets. New assets would be cumulative from a nominated commencement date. The results from these two approaches are set out in table A1.49 of the ROLIB Pty Ltd report.

The inclusion of new assets only would result in a volatile IRTC, that in some ways reflects the "lottery" of the commencement date chosen for the new rule. In the modelling undertaken by ROLIB Pty Ltd, Victoria would be required to pay an IRTC to New South Wales on the basis that some of the relevant assets in New South Wales were constructed during the modelled time period whereas all the relevant assets in Victoria were constructed prior to the modelled time period. The approach of including new assets only for the purposes of calculating the IRTC would reduce certainty and stability upon the introduction of the rule and reduce transparency because it would be more difficult for a customer to predict the outcome of the charging method where a key input into that methodology is the date of construction of the relevant assets.

Further, the CRNP method reflects the usage of the existing network by different customers. Therefore, the intra-regional transmission charging method is already reflecting an allocation of existing assets. So in order to continue with regulatory consistency it is appropriate to apply the IRTC to all relevant assets rather than only new assets on the basis that such an approach would be consistent with approach taken to calculating intra-regional charges.

13.5 CRNP method

There are two main methodologies for incorporating the cost of network elements these are; the standard CRNP and modified CRNP.

The modified CRNP method makes an adjustment for asset utilisation, such that locational charges relating to under-utilised assets are lower, other things being equal, than those relating to fully-utilised assets. The modified CRNP is currently used for calculating intra-regional charges in South Australia and Tasmania (for radial lines only). A standard CRNP approach, where no allowance is made for asset utilisation, is currently used in the remaining regions.

It is understood that it would be straightforward for those TNSPs using modified CRNP to use standard CRNP for calculating LECs. However, it would be administratively onerous for those TNSPs using standard CRNP intra-regionally to apply a modified CRNP method to calculating LECs. This is because collecting and applying asset utilisation data is complex and time consuming. For TNSPs that have never used modified CRNP, there will also be the time and costs associated with the adjustment to the new process.

The additional cost associated with the imposition of a modified CRNP method for TNSPs who do not currently use that method would reduce the net benefits that would be produced by an IRTC. Further application of the modified CRNP method would reduce the operational transparency in the calculation of MLEC. For these reasons the Commission prefers to utilise the standard CRNP method for the MLEC.

13.6 IRTC recovery method

A TNSP will recover net IRTCs from – or rebate net IRTC receipts to - its customers, by adjustment to transmission charges. The issue is whether adjustment should be to the locational transmission charge or the non-locational transmission charge (or, possibly, both).

Adjusting the non-locational transmission charge would be straightforward. Under current rules, the revenue to be recovered from non-locational charges is adjusted by a number of factors. The IRTC charge would simply be included as an additional factor in this rule.

Adjustment of locational transmission would be more complex, although not significantly so. Locational transmission charges are calculated using the CRNP method, so adjustment to these charges would require adjustment to the CRNP inputs.

There will be some aspects of improved price signalling in relation to the inclusion of IRTC in the locational transmission component Although the Commission acknowledge it is only likely to be incremental.

The IRTC will require a true up as, like transmission charges more generally, it will be based on estimated volumes. This means that it will require adjusted when actual volumes are known. The impact of the IRTC on total revenue recovery would be accounted for at that point.

ROLIB Pty Ltd's modelling report shows that adjustment of locational transmission through iteration can give rise to different IRTC charges. The iteration process is complex and, as a result, charges based on this process would seem to lack transparency. The materiality of the change to the customer's overall transmission cost does not warrant the additional complexity, and reduced transparency, that iterations would entail.

However, the calculation of the IRTC has been restricted to locational components only. Therefore, it is consistent with this approach to require that the IRTC also be recovered through the locational component of transmission thereby maximising the locational pricing signals available by adjusting the target revenue.

14 Implementation and the second draft rule

The second draft rule implements the policy as contained above, however, there are a number of additional implementation aspects of the draft rule that the AEMC wishes to highlight to stakeholders and to receive their feedback on. These are questions that in some respects arise because of the methodology the AEMC has selected for the IRTC and in others they arise because of the introduction of an IRTC. Table 14.1sets out the effect that the introduction of the IRTC based on the MLEC will have on the allocation methods and pricing methods, in particular noting that the pricing methods remain unaffected.

Table 14.1 Impact of IRTC on cost allocation and pricing methods

Cost component	Allocation method	Pricing method	Impact of IRTC based on MLEC
Prescribed common services	Allocated to connection points on a postage stamp basis	Postage stamp (eg $/MW/day or $/MWh)	**Allocation** No change to these arrangements **Pricing** No change to these arrangements
Prescribed TUOS services	Split between locationa and non-locational based on 50:50 split or alternative allocation based on a reasonable estimate of future network utilisation and future transmission investment		**Allocation** No change to these arrangements
Locational	Allocated to connection points using a cost reflective network pricing method (less settlement residue auction proceeds)	Three methods available. All are expressed in $/MW/day.	**Allocation** Inter-regional transmission charges added to, or subtracted from, locational cost prior to using cost reflective network pricing method to allocate to connection points **Pricing** No change to these arrangements
Non-locational	Allocated to connection points on a postage stamp basis (less other adjustments, eg over/under recovery)	Postage stamp (eg $/MW/day or $/MWh)	**Allocation** No change to these arrangements **Pricing** No change to these arrangements

Prescribed common services are transmission services that produce equivalent benefits to all connection points without any differentiation based on their location.

Prescribed TUOS services are transmission services that produce different benefits to connection points depending on their location within the transmission system

14.1 Description of the operation of the rule

MLEC Calculation

Each CNSP is required to calculate the MLEC as follows:

- The CNSP must allocate 50% of its annual service revenue requirement (ASRR) for prescribed TUOS services on a locational basis between all connection points within its region, including connection points between that region and other regions. This allocation must be made using the prescribed MLEC CRNP Methodology
- The prescribed MLEC CRNP Methodology is a nationally consistent methodology for attributing the costs of transmission system assets based on the standard CRNP methodology but with certain prescribed requirements as follows:
  - all transmission system assets must be included for the attribution of network costs;
  - operating conditions in all half hour periods of the prior financial year must be taken into account; and
  - peak usage of transmission system elements must be used.

The above methodology will result in an allocation of costs to connection points between regions. These costs will constitute MLEC.

MLEC publication

A TNSP who is a CNSP will be required to publish details on the MLEC by 15 March each year. The NER provides that all TNSPs are required to publish their prices by 15 May each year.

CNSP Charging

A CNSP for region A will invoice the CNSP of the interconnected region B for any MLEC it estimates to be payable in respect of region B in the coming regulatory year.

The CNSP for region B will allocate the net MLEC payable or receivable in respect of region B to the TNSPs located in region B.

TNSP Charging

Each MLEC balance allocated to a TNSP by its CNSP must be allocated for recovery (or pass through) by that TNSP to its customers by way of an adjustment to that TNSP's locational component of prescribed TUOS services.

Allocation of costs and determination of pricing for connection points within its region will otherwise be calculated by the TNSP in accordance with its current practice under the NER.

True up

In subsequent years, each CNSP will calculate a true up amount based on the actual network utilisation information available to it using the same MLEC methodology as described above.

The CNSP for region A will invoice the CNSP of any relevant interconnected region for any true up amount payable in respect of that region. The CNSP for region B then allocates that true up amount in respect of region B to the TNSPs located in region B.

Each TNSP then includes that true up amount as an adjustment to the MLEC amount to be recovered as part of its allocation of the locational component of prescribed TUOS services as described above.

Pricing Methodology

The AER will be required to amend the pricing methodology guidelines in accordance with the introduction of MLEC in the NER.

TNSPs and CNSPs will be required to amend their pricing methodologies to incorporate the calculation and allocation of MLEC in accordance with the requirements of the NER.

14.2 Determination of locational transmission charges for inclusion in MLEC

The second draft rule provides that the estimation and charging for MLEC is to be based upon the proportionate use of transmission system assets using the MLEC CRNP methodology so that the ASRR for prescribed TUOS services is a 50 per cent share to connection points interconnected to the CNSP's region. While this is consistent with the approach and level adopted by most TNSPs, it is not the same as the split between location and non-locational revenue as used by some TNSPs, for example ElectraNet.

The current rules for intra-regional transmission charging allow for an alternative split oflocational and non-locational components of prescribed TUOS services so long as the alternative allocation is based upon reasonable estimate of future network utilisation, need for future investment and proving more efficient location signals. Also, the current rules provide for flexibility to the TNSPs to amend the standard CRNP (as the modified CRNP). These arrangements are not being altered for intra-regional transmission charging.

The Commission selected to specify the 50 percent split for inter-regional transmission charging in order to standardise the approach for the estimation and recovery of MLEC. The alternative is to allow TNSPs to identify their allocation of the ASRR in the same manner as they use for intra-regional transmission charges. However, this could result in charges that are higher or lower for some regions purely based on the methodology for determining locational charges as a portion of .

The AEMC would like stakeholder feedback on the methodology for determining the appropriate share of prescribed TUOS service – locational component for the purposes of the MLEC.

14.3 Public information

The second draft rule requires the following information to be published;

- the AER is required to publish its amended pricing methodology guidelines to take into account the MLEC arrangements;
- the AER is required to publish the TNSPs' proposed amended pricing methodologies to take into account the amended AER pricing methodology guidelines, to take into account the IRTC arrangements and the proposed TNSP arrangements to make adjustments to the ASRR.

Also, the second draft rule requires TNSPs where the TNSP is the CNSP, to publish the IRTC amount by 15 March each year.

Question 1 Public information

The AEMC seeks stakeholder views on any other material in relation to the IRTC that either the CNSP or TNSPs should publicly disclose?

14.4 Information to be contained on CNSP to CNSP IRTC bill

The AEMC has specified that the minimum information to be included on the bill from one CNSP to another CNSP (in addition to the requirement for the TNSP who is a CNSP to publish the MLEC amount for the next financial year).

The second draft rule requires that a MLEC bill must include the following information:

- reasonable details of the calculation of the modified load export charges;
- reasonable details of the calculation made to the MLEC (ie for the true up between estimated MLEC and MLEC based on actual system use.

Question 2 Information to be contained on CNSP to CNSP IRTC bill

The AEMC seeks stakeholder views on any other material that a TNSP or CNSP require to enable them to fulfil their obligations?

14.5 Adjustment of the prescribed TUOS services – locational component for the MLEC

The second draft rule prescribes the manner and sequence for the MLEC to be adjusted for the prescribed TUOS services – locational component, including that it be excluded from the 2 per cent price annual variation as TNSPs prices for prescribed TUOS services – locational component.

Question 3 Adjustment of the prescribed TUOS services – locational component for the MLEC

The AEMC seeks stakeholder views on whether this sequence reflect the most efficient way of incorporating the inter-regional transmission charges into the locational component of the intra-regional charge?

14.6 Sequence for IRTC

The second draft rule is based on the sequence for the calculation of IRTC as outlined in 14.1. This now includes recovery or pass through of MLEC payables or receivables as ana adjustment to the locational component of the ASRR for prescribed TUOS services rather than incorporating MLEC recovery or pass through across the ASRR's for all components of prescribed TUOS services and common transmission services as was outlined in the original draft determination. The IRTC introduces a need for CNSPs to communicate the results of their calculation of IRTC to neighbouring regions to enable them to calculate their intra-regional transmission charges. The TNSP is required to publish their prices for the next regulatory period no later than 15 May. In order to give the TNSP sufficient time to determine the impact of the IRTC on their intra-regional charges the AEMC has required that the CNSP provide the results of the IRTC to the neighbouring CNSP no later than 15 March. The AEMC is of the view that this gives the CNSP sufficient time to determine the IRTC but at the same time gives the neighbouring CNSP and TNSPs sufficient time to include the charge in the locational component of their charges.

Question 4 Sequence for IRTC

The AEMC seeks stakeholder views on whether this sequence reflect the most efficient way of incorporating the inter-regional transmission charges into the locational component of the intra-regional charge?

14.7 Commencement

The second draft rule includes a commence date of IRTC of 1 July 2014. This would require the first publication of IRTC under the MLEC by 15 March 2014. This is just over 1 year after the expected completion of the rule change on 28 February 2013. It is the AEMC's view that this provides sufficient time for the AER to revise its guideline on transmission pricing and for the TNSPs to update, and publish, an updated method for the calculation of both intra and inter regional transmission charges.

Question 5 Commencement

The AEMC seeks stakeholder views on whether there is a more appropriate date to commence the operation of inter-regional transmission charging.

14.8 Savings and Transitional provisions

The AEMC has not incorporated any transitional provisions in the second draft rules.

Question 6 Savings and Transitional provisions

The AEMC seeks stakeholder views on whether there is any specific need for savings and transitional provisions to enable the MLEC to be introduced into the NER?

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	Annual service revenue requirement
CNSP	Co-ordinating Network Service Provider
CRNP	Cost reflective network pricing
DPI	Victorian Department of Primary Industry
IRTC	Inter-regional transmission charge
LEC	Load export charge
LRMC	Long run marginal cost
MCE	Ministerial Council on Energy
MEU	Major Energy Users Ltd
MLEC	Modified load export charge
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NGF	National Generators Forum
NTP	National Transmission Planner
OEPC	Tasmanian Office of Energy Planning and Conservation
RIT-T	Regulatory investment test - transmission
Group of generators	AGL Energy, Alinta Energy, International Power GDF-Suez, LYMMCo

SRA	Settlement Residues Auction
TFR	Transmission Frameworks Review
TNSP	Transmission network service provider
TUOS	Transmission use of system

A Summary of issues raised in submissions

Consultation paper

Stakeholder	Issue	AEMC response given in first draft determination
General views and issues on the Rule Change Request		
Gallaugher & Associates (p. 1)	In broad terms supports the concept of inter-regional network charges proposed but considers there are many serious flaws with the current regulatory and economic framework for the provision of transmission services in the NEM.	The Commission notes that the specific points raised in Gallaugher & Associates submission, as well as other submissions, on the design of the load export charge are discussed in this determination.
Hydro Tasmania (p. 1)	Broadly supports the proposal to introduce inter-regional transmission charging. Has reservation with the Commission's inter-regional transmission charging proposal on the prediction of future network flows as a basis for assigning costs shares.	As discussed in chapter 5 of this determination, the Commission considers that the current approach to allocating costs can accommodate load export charges. Specific discussion relating to issues in Tasmania are discussed in section 7.4.2.
Integral Energy (p. 1)	Supports the principle that customers who import power from another region should contribute towards the transmission costs thereby incurred in the exporting region and considers that the load export charge approach set out in the Consultation Paper provides a suitable mechanism for doing so.	The Commission notes the comments made.
Grid Australia (p. 3)	Supports the implementation of a load export charge based on the locational component of prescribed transmission prices to commence from 1 July 2012 at the earliest.	As discussed in sections 5.4.3 and 6.4.3, the Commission considers that a 1 July 2012 commencement date for the load export charge would be more appropriate.
The Major Energy	While the Rule change request conceptually seeks to	As discussed in section 2.6, the load export charge may result in a

Stakeholder	Issue	AEMC response given in first draft determination
Users Inc (MEU) (p. 3)	impose a higher degree of cost reflectivity, it has the potential to create more problems than it solves e.g. some beneficiaries will receive a greater benefit at the expense of other customers. Also considers that the Rule change proposal lacks quantification and undermines key principles underpinning the NEM [in ways as discussed in other sections of the MEU's submission as outlined below].	one-off redistribution of charges among customers in different regions. However, this redistribution would result from the improvement in cost-reflectivity, which would benefit all customers in the long term. The modelling outcomes has shown the potential cross-subsidies that currently exist. The Commission does not consider the Rule change undermines the underlying principles of the NEM (as discussed in response to the MEU's issues below).
MEU (p. 7)	Although the MEU supports, in principle, allocating the costs of interconnectors to the beneficiaries of the interconnectors, it raises a number of issues and concerns on the proposed arrangements. pp. 4-5. In addressing these inconsistencies in the proposed arrangements, the MEU is concerned that the complexity that then arise will make the implementation too complex to deliver a sensible and commercial outcome for customers.	In making this determination, the Commission has clarified the principles of the load export charge, where any export load would be treated in a similar manner to existing customer load. In doing so, the Commission considers that the load export charge provides a proportionate solution to the requirement of inter-regional transmission charging arrangements and that its implementation would not be complex.
MEU (p. 7)	The Rule change proposal posits that customers will accrue significant commercial benefit by the implementation of the change and therefore it should cover the costs that generators and TNSPs will incur as a result of the Rule change. But considers there is no attempt to quantify either the costs or benefits of the proposal, let alone the materiality of the issue.	The Commission considers that the Rule change proposal recognises the potential benefits of introducing inter-regional transmission charging arrangements. The materiality of the potential impact of an load export charge is discussed further in section 7.4.
MEU (pp. 8-9)	Considers that the Rule change request had its origins from a request of the MCE for the AEMC to conduct the Climate Change Review and considers that "[e]ffectively the AEMC sees that its recommendations [from the Climate Change Review] will assist the implementation of the eRET and CPRS policies, irrespective of the quantum of costs involved so long	The Commission notes that the objective of the Climate Change Review was to consider how the current energy market frameworks would respond to the expanded eRET and the CPRS and how any potential impacts of these policies on the market may be managed. The Commission did not consider how any of these policies should be implemented. In addition, the Commission notes that inter-regional transmission charging has been an issue that the market has

Stakeholder	Issue	AEMC response given in first draft determination
	as the market outcomes (which will reflect the interventions) are seen to be 'efficient' and 'reliable'".	considered and assessed for some time, including consideration by the National Electricity Code Administrator in its transmission and distribution revenue review completed in 1999. The Commission is now assessing the proposed load export charge through this Rule change process to consider whether the proposed arrangements would be in the long term interest of customers.
MEU (p. 12)	In regards to cost-reflectivity considerations, raises the issue of the cost of power compared with the cost of transmission. Notes that the reasons for a region to be a normally importing region are many but the main reason is that the prices of generation in an importing region are higher than those in a normally exporting region. Just because there is a price differential does not mean that this differential is more than the additional costs of providing transmission.	The Commission notes the issue raised however the cost of transmission is typically a small proportion of the total costs for electricity that customers face. Additional discussion is outlined in section 7.4.
MEU (p. 13)	Notes that if an importing region is expected to pay for transmission costs within an exporting region, from a consumer viewpoint, this makes generation from an exporting region a higher cost - effectively the cost to customers in the importing region for the imported generation becomes the dispatch price for the generation plus the load export charge. The proposal for allocating transmission services from an exporting region however implies that a generator outside a region will still be dispatched on the current basis. This raises the question - is the proposal really economically efficient and does it maintain competitive neutrality?	The Commission notes that the load export charge is intended to improve the cost-reflectivity of transmission assets. In terms of whether the transmission investments themselves are efficient, the existing framework which provides for the role of the National Transmission Planner and the Regulatory Investment Test for Transmission go towards ensuring efficient transmission investments are made.
MEU (p. 14)	Considers that the Rule change proposal does not assess whether customers will pay more for their delivered power under the proposed change than	The load export charge would relate to the regulated revenues of TNSPs and interconnectors. As the purpose of the revenue regulation process is to ensure that only efficient costs would be recovered, the

Stakeholder	Issue	AEMC response given in first draft determination
	necessary and whether the proposal might reduce competitive neutrality between generators and regions.	Commission considers that the mechanisms in place ensures that customers would not pay more than necessary. In addition, as the load export charge would apply to all TNSPs, and revenues are regulated, there would not be any impact on competitive neutrality.
MEU (p. 18)	The complexity of implementing the proposal might reach a level where the value of the proposal has only a marginal benefit compared to the costs of implementation and the degree of moving from the simplicity of the current arrangements.	The Commission notes that as the pattern of interconnector flows responds to changes in the underlying market requirements, introducing an inter-regional transmission charging mechanism is an important step in ensuring that prices are cost-reflective.
National Generators Forum (NGF) (p. 1)	On balance, supports the proposed improvements to the transmission charging arrangements. However, have a concern on the potential difficulty to develop and set the load export charge with a degree of certainty. Energy movement from one region's transmission network to an adjoining region's network is likely to be volatile. We expect the energy forecasts used to work out a load export charge to be similarly variable. This could create problems around certainty. Do note, however, that forecasting energy flows for customer loads at existing connection points on the transmission system are relatively stable.	The provisions in place provide that charges to be applied to customers cannot vary by more than 2 per cent per annum compared with the load weighted average price for the locational component of transmission charges. The Commission considers that this provides a degree of certainty. In addition, to the extent that the load export charge improves cost-reflectivity, any volatility in costs would be reflected in prices. In addition, as noted above, the transmission charges component of a customer's bill is relatively small.
NGF (p. 2)	Considers the proposed methodology of implementing a load export charge is consistent with the current methodology in the AER's electricity transmission network service providers pricing methodology guidelines.	The comments are noted.
AEMO (p. 1)	Supports in principle the introduction of inter-regional transmission charges. Considers the proposal is consistent with the establishment of the role of the national transmission planner within AEMO and	The comments are noted.

Stakeholder	Issue	AEMC response given in first draft determination
	recognition of the need to coordinate the development of the grid on a national basis. Considers it would be incongruous to plan and develop the grid on a national basis without recognising this in transmission pricing.	
AEMO (p. 1)	In undertaking this Rule change notes that there is the need to recognise that transmission pricing is complex and that detailed procedures are not specified in the Rules and the implementation in respect to a number of details are likely to vary from one region to the other and that the overall outcomes of the methodology can be very sensitive to a range of decisions. The final process to be determined should seek to deliver both a workable and consistent process and meet the MCE's objectives in introducing inter-regional transmission charging.	The comments are noted. The Commission also acknowledges the work that TNSPs and AEMO have completed in providing modelling for this Rule change request, which has assisted with the analysis and understanding of the proposed arrangements.
EnergyAustralia (pp. 1-2)	Considers that quantitative analysis of the potential impact of the proposed change on stakeholders, including customers, should be completed and subject to further consultation.	The Commission notes the issue and the results from the modelling undertaken by TNSPs, including AEMO in its capacity as a TNSP in Victoria, are discussed in section 7.4.
Composition and definition of the load export charge		
Integral Energy (p. 1)	Supports the extension of the current transmission pricing principles to determining the load export charge, including both locational and non-locational components for the relevant TUOS charges.	The comments are noted.
Integral Energy (p. 2)	As a general principle, would like to see greater stability and transparency in transmission pricing. In the current context, supports the proposed Rule setting out notification processes and requiring a level of information disclosure from the CNSP that ensures	The comments are noted. TNSPs would be required to provide estimates to each other and, where possible, to DNSPs. The AER would also be required to amend its pricing methodology guidelines and TNSPs would be required to amend their pricing methodologies.

Stakeholder	Issue	AEMC response given in first draft determination
	the impact on distribution and retail tariff notification processes can be managed as effectively as possible.	
Grid Australia (pp. 3, 6-7)	The inclusion of the postage stamped components of prescribed transmission prices is likely to result in importing regions making a contribution significantly beyond the long run marginal costs of existing and new transmission assets which support inter-regional flows. Considers the inclusion of these components departs from the principles of the current pricing regime and would not be consistent with the NEO.	Discussion is outlined in chapter 5.
Grid Australia (p. 6)	To include postage stamped components would be to impose costs on customers of an adjoining region that bear no relation to their proportionate use of the adjoining region's transmission system assets. Such a view is also consistent with the ACCC position where it was expressed that rather than to be used as a tool for signalling, the non-locational component is to serve as a recovery mechanism that will cause the least distortion possible.	Discussion is outlined in chapter 5.
Grid Australia (p. 11)	The volatility of annual energy flows across interconnectors would lead to considerable volatility in the load export charge on a year to year basis. The effect of this volatility on customers (in both the importing and exporting regions) would depend on the relative materiality of the charge. Is concerned that the introduction of the postage stamp components to the load export charge will materially increase the impact of the load export charge on customers and may lead to even greater volatility from year to year.	The Commission acknowledges that it may be difficult to predict how interconnector flows will vary in the future. However, it is noted that any changes in the overall interconnector flow profiles would happen over time. As the load export charge is intended to increase the cost-reflectivity of prices, if there is volatility in the underlying costs then this would be reflected in the charges - although any variations in costs would also be impacted by the redistribution of settlement residue auction proceeds. As noted above, the load export charge and transmission charges in generation are not expected to be a significant portion of a customer's bill.

Stakeholder	Issue	AEMC response given in first draft determination
NGF (p. 2)	A load export charge that includes both a locational and non-locational component of prescribed TUOS implemented in a way that minimises price volatility is suitable. We expect that the AEMC will engage with TNSPs to facilitate this outcome.	Discussion is outlined above and in chapter 5.
Hydro Tasmania (p. 2)	In the case of Victoria/Tasmania inter-regional transfer, forecasting of network flows is particularly difficult, depending as they do on hydrological inflows in Tasmania, which can vary ±30%. Would ask the Commission consider how the process for determining the inter-regional transmission charges could cater for potentially large swings from year to year, in inter-regional transfer payments between Victoria and Tasmania, without resulting in unmanageable variations in Customer costs.	Discussion is outlined above and in section 7.4.2.
Grid Australia (p. 4)	To define the export load the appropriate quantity to use would be a prescribed capacity of the notional interconnector, which defines the capacity in place of a "contracted demand".	The Commission notes the suggestion proposed. As discussed in section 5.4.3, the Commission considers that the prescribed capacity would be required.
Grid Australia (p. 5)	The definition of notional interconnector capacity will significantly impact the magnitude of the TUOS non-locational and common service component charges. Considers that two options are readily available: (1) the capacity used by AEMO in the settlement residue auction process; and (2) the maximum directional flow in the notional interconnector in the previous year.	As discussed in section 5.4.3, the Commission considers that the maximum directional flow on the notional interconnector would be an appropriate measure.
Grid Australia (p. 8)	Notes that the pricing methodology mandates that the contract agreed maximum demand should only be	The Commission agrees that an appropriate definition would need to be introduced and considers that maximum flow on the notional

Stakeholder	Issue	AEMC response given in first draft determination
	used for charging if the customer's connection agreement or other enforceable instrument governing the terms of connection stipulates a fixed maximum demand and penalties for exceeding that demand. Consideration should be given to the ability to satisfy this requirement under the proposed arrangements.	interconnector in the last year may be used for this purpose.
Grid Australia (p. 6)	Although, in simplistic terms, customers in importing regions use the shared network services in a similar way to customers with the exporting region, it is not clear that customers in the importing region would be readily able to associate their behaviour with the load export charge allocated to them and respond appropriately. This would depend, in part, on the relative materiality of the inter-regional charge.	The Commission notes that the load export charge mechanism would provide an important step in the pricing arrangements to accommodate likely future changes in interconnector flows. The modelling results are discussed in section 7.4.
MEU (pp. 13-14)	If the regional node in the importing region is located closer to the border than the regional node in the exporting region, then the costs of transmission to the border in the exporting region are much higher than the costs of transmission to the border of the importing region. Therefore there will be a disparity between the rate of the "load export charge" in one region compared to another. Despite this as power flows in both directions, it is assumed that the amount of power transferred is a net amount. This means that the export from the net importing region has a lower value in terms of dispatch price plus load export charge than export from the net exporting region in terms of dispatch price plus load export charge.	As discussed in chapter 5, the locational component of the load export charge is calculated in a similar method to other loads. That is, the Rules require the cost-reflective network pricing (CRNP) or the modified CRNP methodology to be used to determine the proportionate use of the system. This methodology is not related to the location of the regional price node, which relates to the determination of the spot price.
MEU (p. 16)	The proposal to introduce a load export charge, which would have a locational component, would mean that the locational element of TUOS in the importing region	As discussed above, the calculation of locational transmission charges is based on a customer's proportionate use of the network assets. This is related to the location of the customer on the network itself and not

Stakeholder	Issue	AEMC response given in first draft determination
	will become distorted by the addition of locational TUOS from the load export charge. As locational TUOS is calculated from the regional node, this approach will provide a penalty on customers located close to the point of importation. Considers that neither the consultation paper or the Rule Change Request provided any reason for making this change, yet it will necessarily increase the costs incurred by customers located close to an importation point.	related to the location of the regional reference node. Additional discussion is outlined in section 5.4.3.
NGF (p. 1)	Supports a load export charge that reflects the costs of all assets which contribute to export flows to the adjoining region as if an adjoining region was a load on the region boundary.	The comments are noted.
EnergyAustralia (p. 3)	The major proportion of the non-locational costs is associated with assets servicing customers within a region, rather than the small number of assets near the jurisdiction interface, whose locational cost would be allocated to customers in another jurisdiction. Passing on these charges between regions, particularly in respect of sunk assets, would not contribute to "efficient investment in, and efficient operation and use of, electricity services". Therefore, is not convinced that passing on the non-locational component of TUOS to another region contributes to pricing efficiency or to the market objective.	Discussion is outlined in chapter 5.
EnergyAustralia (p. 3)	If the goal of the pricing arrangements is to promote efficient pricing signals, the AEMC could consider demonstrating to customers that it has considered whether there should be a proportional allocation of cost to generators upstream of inter-regional	The Commission notes the comments raised and notes that broader issues relating to the pricing and other regulatory provisions for the transmission network will be considered by the AEMC under the Transmission Frameworks Review.

Stakeholder	Issue	AEMC response given in first draft determination
	interconnectors to provide efficient pricing.	
Calculating and recovering the load export charge		
Integral Energy (p. 1)	Supports the adoption of consistent pricing methodologies across the NEM regions for the determination of load export charges, wherever feasible.	The Commission has maintained the principles of the existing framework for Chapter 6A of the Rules where the Rules set out the principles and additional implementation details would be set out in the AER guidelines. The Commission notes that the principles are aimed at promoting the adoption of consistency across regions and the AER is required to take this factor into consideration.
Grid Australia (p. 7)	By treating the point(s) of connection of a notional interconnector as a connection point the prices and charges can be calculated in a manner broadly consistent with the principles.	The comments are noted and additional discussion is outlined in section 5.4.3.
Grid Australia (p. 7)	A broader range of transitional provisions are required to allow CNSPs to modify their approved pricing methodologies to the extent required to implement the changes arising from this Rule change. This would eliminate the double jeopardy inherent in the requirement to be compliant with both the Rules and the approved pricing methodology.	As discussed in section 6.4.3, the Commission has provided transitional provisions to allow TNSPs to amend their pricing methodologies.
Grid Australia (p. 7)	The most material difference between pricing methodologies is the implementation of the CRNP in the Victoria region, which has been identified in the Rule change request.	The comments are noted.
Grid Australia (p. 7)	ElectraNet and Transend use approved implementation of the modified CRNP methodology and considers this has no material impact on the proposed load export charge.	The comments are noted and additional discussion on the calculation of the load export charge is set out in chapter 5.

Stakeholder	Issue	AEMC response given in first draft determination
Grid Australia (p. 8)	The Rules should not be overly prescriptive in the calculation of the load export charge. Given the extremely complex nature of prescribed transmission pricing to introduce additional complexity in the Rules runs the real risk of unintended consequences arising. Grid Australia considers it would be more appropriate for the more detailed implementation issues to be dealt with in changes to TNSP pricing methodologies, which would be subject to approval by the AER.	As discussed in chapter 5, the Commission has maintained the existing principles of Chapter 6A where the Rules set out the principles for revenue and pricing and additional implementation details are dealt with under the AER's guidelines and TNSPs' pricing methodologies. Some clarifications to address the requirements for the load export charge have been added.
Grid Australia (p. 9)	Notes that in order for the CRNP process to operate the energy flows in both directions on the interconnector(s) must be modelled rather than setting the flows to zero when it is importing. This is consistent with the way interconnectors are currently modelled for prescribed pricing. Conversely, when calculating postage stamped prices and charges only the half hourly load (export) component of the energy flow should be considered as otherwise it is possible to have negative charges in some months. This does not appear consistent with the intent of the Rule change request.	The Commission notes that the Rules would provide the principles of the load export charge. The AER's pricing methodology guidelines would provide additional guidance on any specific implementation issues and TNSPs' pricing methodologies would provide additional clarification. This process would provide the opportunity to utilise the expertise of the AER and TNSPs.
Grid Australia (p. 9)	There is no available methodology which would allow the export charge from the adjacent region to be passed through to customers using the CRNP methodology which would not in turn influence the export charge to the adjoining region. Accordingly an alternative methodology is required. The most administratively efficient mechanism would be to prorate the charge to customers on the basis of their expected annual charge for that component of their prescribed transmission charges.	The Commission understands that TNSPs, through the modelling process, have been considering the requirements for performing the actual calculations for a load export charge and that it may be possible for an "iterative" approach to be taken to allow the required charges to be calculated.

Stakeholder	Issue	AEMC response given in first draft determination
MEU (pp. 9-10)	Noting the requirement under the clause 6A.23.4(e) of the Rules relating to the recovery of prices for prescribed TUOS services are to be recovered based on demand at times of greatest utilisation of the transmission network, questioned why AEMO, as the Victorian TNSP, must be required to change its pricing policy from one which explicitly meets the pricing requirement set by the Rules, to one that does not meet the Rules in order to meet the inter-regional transmission charging arrangements.	The Commission notes that the amendment that is required of AEMO's pricing methodology relates to the calculation of the locational component of the prescribed TUOS service charge. This locational component must be calculated using either the CRNP or the modified CRNP methodology. Under the modelling processes of these methodologies (which are defined under Schedule S6A.3 of the Rules) there are different ways of achieving the pricing principles under the Rules of modelling the system to determine the times of greatest utilisation of the transmission network. The amendment to AEMO's methodology would be more consistent with the introduction of the load export charge and would prevent any distortion being created in the price outcomes. Additional discussion is outlined in section 6.4.3.
MEU (p. 10)	Concerned that the current proposal to allocate inter-regional costs in an exporting region to power importing regions does not take into account benefits of interconnection in terms of reliability. The mere presence of the ability to transfer power from one region to another when power shortages occur, has major value, even if the transfer occurs only occasionally. The MEU has a concern that the cost allocation approach used will overlook this benefit to a normally exporting region, and transfer these costs to a region which usually imports power.	The NTP and RIT-T ensures that efficient transmission investments are made giving consideration to a number of factors including the potential market benefits provided by each investment. Through these processes under the regulatory framework, appropriate consideration is given to potential benefits of each investment.
MEU (p. 14)	The change proposed by the rule implies that the load export charge will be based on the volume of energy transferred, as if the load was located at the border of the two regions. What is totally absent from the proposal is how this apparently simple philosophy will be addressed in the complexity that is the NEM and its structure which allows free flow of electricity between regions.	As outlined above and discussed in chapter 5, the Rules sets out the principles to be applied. The AER's pricing methodology guidelines and the TNSPs' pricing methodologies would set out additional implementation considerations.

Stakeholder	Issue	AEMC response given in first draft determination
MEU (p. 15)	There is a need to clarify if the approach is to require each interconnector to be assessed separately, or whether the flows on the two interconnectors are to be aggregated. Further there is a need to reflect the value of these counterflows to each region.	As discussed in chapter 6, the load export charge would be based on gross flows.
MEU (pp. 16-17)	Has considerable doubt as to the methodology which will be used to develop the load export charge for transferring power from one region to another. Considers there are a number of issues that would need to be addressed including whether the load export charge is an average of the net flows or is to be calculated for both regions; determining the appropriate cost allocation. The implication of the Rule change request is that cost allocation, when developing the load export charge, should reflect the times of maximum demand in the region, yet the Rule change proposal implies that the cost allocations will be made on the averaging used by most TNSPs.	The Commission notes that prices generally are based on a forecast value or historical amount. However, once actual flows are known, adjustments would be made such that the prices paid by customers reflect the actual usage over time.
MEU (p. 27)	Due to the various bases on which the load export charge could be developed, there is a need for a high degree of prescription so that all customers are treated on a consistent basis, bearing in mind that under the current approach to pricing methodology, almost every TNSP has a different approach. It would be bizarre if the pricing approach used by one TNSP resulted in a lower cost for the same service.	The Commission considers that it is desirable that a consistent approach across the NEM is adopted where appropriate while allowing a certain degree of discretion to the AER and TNSPs to adopt methodologies that reflect any unique circumstances in a region. Given the nature of the load export charge, the Commission considers the greater co-ordination between TNSPs would be encouraged in order to facilitate the required calculation processes.
NGF (p. 2)	Supports a load export charge with a locational and non-locational component of prescribed TUOS, and the charge from prescribed common services to be charged to TNSPs in the relevant interconnected	The comments are noted.

Stakeholder	Issue	AEMC response given in first draft determination
	areas.	
AEMO (p. 4)	A consistent national approach needs to be determined, justified and implemented as part of introducing inter-regional TUOS.	As discussed above and in chapter 5, provisions under the Rules have been clarified to accommodate the introduction of the load export charge. In addition, the AER and TNSPs would be required to amend the pricing methodology guidelines and pricing methodologies respectively.
AEMO (p. 4)	The current Rules provide for an arbitrary 50:50 split into the locational and non-locational components of prescribed TUOS charges, which most regions adopt. The Rules also permit other approaches which seek to better reflect the intent of giving efficient price signals. One would expect that a consistent approach needs to be adopted nationally in this respect.	Discussion is outlined in section 5.4.3.
AEMO (p. 4)	The Rules allow the adoption of either CRNP or a modified CRNP process. The Rules also provide little detail in the implementation of either approach. We consider that the whole approach needs to be checked to ensure that it works appropriately and deals with new forms of non-synchronous generation. Also considers that further work is required on consistency of approach.	The Commission understand that TNSPs, including AEMO in its capacity as a TNSP in Victoria, are further analysing the application of the CRNP and modified CRNP methodologies to consider the impact of non-synchronous generation on these methodologies and that a Rule change request may be made to address any potential amendments required.
AEMO (p. 4)	The allocation of a proportion of the non-locational component to the load export charge needs to be questioned. If it remains, a consistent approach would need to be decided and implemented nationally at least in respect of the portion assigned to customers in importing regions.	The composition of the load export charge is discussed in section 5.4.3.
AEMO (p. 5)	The locational component of prescribed TUOS service is based on CRNP or modified CRNP methodology	The composition of the load export charge is discussed in section

Stakeholder	Issue	AEMC response given in first draft determination
	which itself is based on the value that network assets provide to network users. Times of greatest value generally correspond to times of regional system peak and higher prices. An interconnector is no different in this regard - it will have greatest value to the network users in an importing region at times of peak demand. It is therefore more efficient for the inter-regional TUOS rules to limit the charges attributed to an importing region to the locational component of the exporting regions' prescribed TUOS charge and guiding when the appropriate survey period to measure and model system loading.	5.4.3.
AEMO (p. 6)	By its nature, the non-locational component of prescribed TUOS service charges is inefficient because no account is taken of its utilisation in the network by the importing region and it is not based on the CRNP or modified CRNP calculations. As such, non-locational charges do not appear to have these same efficiency outcomes. If the adjusted non-locational component is to be part of inter-regional TUOS charging regime, then consideration should be given to the option of a single national non-locational price where the NEM aggregate is allocated to all NEM transmission users independent of their region and particular interconnector flows.	The composition of the load export charge is discussed in chapter 5.
AEMO (p. 6)	A change in the methodology of allocating transmission costs nationally raises the possibility of a quantum change in a region's TUOS charges. This is also an issue for long term charges where movements in generation investment and dispatch have a material impact in TUOS pricing. This is both a practical implementation issue and also a concern in terms of	Price volatility is discussed in section 7.4.

Stakeholder	Issue	AEMC response given in first draft determination
	efficient price signalling. The value of these measures in terms of their ability to drive more efficient outcomes needs to be questioned if they exhibit a high level of volatility from year to year.	
EnergyAustralia (p. 6)	Should the Rule change proceed, the overriding principles concerning cost allocation to intra-region load connections using the CRNP allocation approach are also appropriate for interconnected loads. However, again, NEM participants would benefit from quantitative analysis being undertaken to determine the impacts.	TNSPs through Grid Australia and AEMO, in its capacity as a TNSP in Victoria, have prepared modelling on the potential impact of the load export charge on the redistribution of transmission charges. Modelling results are discussed in section 7.4.
EnergyAustralia (p. 7)	An obligation needs to be placed on the TNSP in the importing region to pass on [the locational component of the inter-regional TUOS] in a cost reflective manner to DNSPs in the region. In addition, considers that economic price signals would be preserved only if inter-region postage stamp price components were recovered on the same basis in the importing region.	The recovery of the load export charge is discussed in section 5.4.4.
Treatment of settlement residue proceeds; Market Network Service Providers		
Integral Energy (p. 2)	Questions whether the proposed change in the way that inter-regional settlement residue auction proceeds are returned to customers in the importing region is likely to mean a net improvement in the locational signalling. Ideally, Integral Energy would like to see the Commission provide analysis that demonstrated that reducing the auction proceeds available to customers who import across the interconnector doesn't over-value the congestion costs and therefore potentially distort the investment signal. It may also be appropriate to review the effectiveness of the change	As discussed in section 5.4.5, the Commission considers that settlement residue auction proceeds should continue to be returned to customers on a locational basis.

Stakeholder	Issue	AEMC response given in first draft determination
	after a period of several years.	
Grid Australia (pp. 7, 9)	The change to prevent the locational return of settlement residue auction proceeds to customers in the exporting region is a material departure from the principles. Considers that an alternative would be to include it as an adjustment to the prescribed TUOS services - pre-adjusted locational component - customer connection points. This would then result in it being allocated in a manner closer to the proportional use of the assets.	As above.
AEMO (p. 4)	The return of settlement residue auction proceeds would be more efficient through the locational component since the receipts arise from the use of the interconnector. Ideally the SRA auction proceeds would be netted off the amount transferred as the load export charge from the adjacent region and allocated locationally.	As above.
NGF (p. 2)	Supports settlement residue auction revenues, which are currently offset against a common service charge. Under this proposal, all customers receive a more even spread of revenue from SRA auctions.	As above.
EnergyAustralia (p. 8)	Supports in principle the proposed change to return the settlement residue auction proceeds to customers via the non-locational component of TUOS. Considers that the proposed change would be an improvement since the year on year variation of settlements surpluses leads to instability in the cost reflective components of TUOS charges. However, notes that participants would benefit from quantitative analysis	As above.

Stakeholder	Issue	AEMC response given in first draft determination
	being undertaken to determine impacts for customers.	
MEU (p. 26)	An MNSP should pay for the load export charge just as an exporting region TNSP would do so for providing the same service directly across a regulated interconnector. This approach is consistent with the concept that the beneficiary pays for the provisions of assets needed to deliver the service to it, and reflects equity between customers in an exporting region with the MNSP that uses those assets for generating profits for itself. Further it reflects the analogy of an MNSP being effectively a generator at the regional boundary.	The proposed provisions allow for any assets that are used by an MNSP, and where the costs for the assets are regulated, to be included in the load export charge. Otherwise, MNSPs are excluded from the load export charge provisions as the revenue and prices of MNSPs are not regulated where MNSPs earn their revenue from participating in the spot market.
NGF (p. 3)	Supports the exclusion of MNSPs from the proposed load export charge. As MNSPs are unregulated in the NEM, they are excluded from the pricing provisions of Chapter 6A of the Rules. Furthermore, MNSPs recover their revenues from the market and are not relevant to developing a load export charge. However, this need not limit charging of inter-regional TUOS charges between regulated Network Service Providers on either side of a MNSP.	MNSPs will be excluded from the load export charge.
AEMO (p. 6)	It is appropriate to exclude MNSPs from the inter-regional transmission charging process. However noting that inter-regional flows do occur over MNSPs and will need to be taken into account in the load flow modelling analysis and decisions taken as to how to treat any sums allocated to their connection points in this process.	As above.
EnergyAustralia (p. 8)	It would be inappropriate for the presence of Basslink (or any other MNSP) to inhibit the transfer of a TUOS charge between NEM regions. Considers that the	As above.

Stakeholder	Issue	AEMC response given in first draft determination
	arrangements will require ether: (1) the MNSPs, as interconnected parties, to receive TUOS charges from the exporting region and then to recover these charges from the importing region; or (2) inter-region TUOS charges are settled directly between the TNSPs connected to a MNSP. Considers the second alternative would be more efficient from the perspective of transaction costs and administrative complexity.	
Transition and implementation		
Integral Energy (p. 1)	Supports the transitional arrangements proposed in the Consultation Paper.	Implementation and transitional requirements are discussed in chapter 6.
Grid Australia (p. 10)	With regards to administrative efficiency and the level of prescription for administrative processes, considers that specifying gross payments on a monthly basis with provisions for other arrangements to be agreed between parties would be reasonable. In the absence of a connection agreement or other enforceable instrument between adjoining CNSPs also considers it would be appropriate to specify default conditions or require terms to be agreed between parties. Does not believe that any additional prescription would be warranted.	The Commission generally agrees that the level of prescription in the Rule proposed by the MCE in relation to the CNSP billing requirements appear to be reasonable and have been reflected in the Draft Rules.
Grid Australia (p. 10)	There does not appear to be a material increase in the prudential risk to be managed as a result of the proposed requirements.	The comments are noted.
Grid Australia (p. 11)	It is appropriate for the AER to amend the pricing methodology guidelines to take into account the impacts of this Rule change process for proposed	The Commission agrees that the AER should amend its pricing methodology guidelines to reflect the new requirements for the load

Stakeholder	Issue	AEMC response given in first draft determination
	pricing methodologies submitted as part of future revenue applications.	export charge. This is discussed in sections 5.4.3 and 6.4.3.
Grid Australia (p. 11)	Considers it is appropriate to have a general transitional provision allowing CNSPs to modify their approved pricing methodologies to the extent required to implement the changes arising from the Rule change. As with the AEMO specific transitional provision it would be appropriate to have the AER approve these proposed changes. It would not be necessary for the guideline to be amended in order for the AER to assess the changes required to the pricing methodologies within the revenue control period.	The Commission agrees that TNSPs should be able to amend their pricing methodologies to take into account the new requirements. This is discussed in sections 5.4.3 and 6.4.3.
Grid Australia (p. 12)	Consistent with Grid Australia's previous submissions, strongly supports the adoption of 1 July 2012 as the earliest prudent commencement date. This is due to: • the requirement to amend pricing methodologies; • that Power link will be subject to chapter 6A of the Rules at that time; and • that the CNSPs will be required to commence the calculation of the charge for adjoining CNSPs as early as January 2011 to meet the AEMC's proposed commencement date.	As discussed in section 6.4.4, the Commission considers that a 1 July 2012 implementation date would allow for sufficient public consultation on the pricing methodology guidelines and pricing methodologies, which would require amendment by the AER and TNSPs respectively.
EnergyAustralia (p. 10)	Does not believe that the proposed arrangements could reasonably be implemented by 1 July 2011. Elsewhere in its submission, it has stressed the need for modelling to be undertaken to identify the pricing impacts of the proposal before the policy details and	As above.

Stakeholder	Issue	AEMC response given in first draft determination
	the date of its introduction are established.	
NGF (p. 2)	Proposes that the AER reviews the pricing methodology of all TNSPs to ensure they comply with their pricing methodologies following the implementation of a load export charge.	As above.
NGF (p. 3)	Proposes that the AER formulates any required changes to its pricing methodology guidelines to accommodate a load export charge. p. 2. Submits that the AER should refrain from adopting a new set of guidelines, independent of the pricing methodology guidelines, to develop a load export charge.	The Commission agrees that a separate set of guidelines would not be required and that the AER should be required to amend its existing pricing methodology guidelines.
NGF (p. 2)	Proposes that TNSPs apply a load export charge which could be implemented on a gross or net basis, but should be levied on the same basis throughout the NEM. They would set the charge based on the use of each individual TNSP's assets on either side of a region and ensure it was developed in accordance with their own pricing methodology. p. 2. Submits that the AER should develop consistent and transparent guidelines in gross or net payment procedures with TNSPs for the billing of inter-regional TUOS.	The Commission agrees that each TNSP/CNSP would set charges based on each individual TNSP's assets within its region and developed in accordance with its pricing methodology. The AER will also be required to amend its pricing methodology guidelines to take into consideration the load export charge requirements.
NGF (p. 3)	CNSPs should provide estimates of the load export charge to be levied to other CNSPs before 15 May each year.	The Commission agrees that this would be required to allow each TNSP to finalise its pricing proposal within the required timeframes. Discussion is outlined in chapter 6.
NGF (p. 3)	Credit issues between CNSPs regarding the billing of inter-regional TUOS can be resolved between TNSPs without guidance from the AEMC.	The Commission agrees that additional guidance should not be necessary.

Stakeholder	Issue	AEMC response given in first draft determination
NGF (p. 4)	The charge could potentially impact customers in each region differently as charges in one region increase and charges in another region decrease. Therefore, to deal with any unfortunate impacts associated with this charge, we support transitional provisions for the TNSPs to initially recover the load export charge through the non-locational component of TUOS and permit AEMO to revise its pricing methodology.	The Commission considers that the transitional arrangements under the Rule change request to allow the load export charge to be initially recovered on a non-locational component only was to allow some form of load export charge to be introduced without requiring all TNSPs to amend their pricing methodologies. However, given that the TNSPs will now be required to amend their pricing methodologies under the Draft Rule, the Commission considers that the transitional provision to allow the load export charge to be recovered on a non-locational basis only would not be required.
AEMO (pp. 4-5)	The derivation and publication of transmission prices must always work to a tight timetable to allow them to be incorporated in distributor's tariffs an retailers' price offers. The national process therefore needs to fit to these requirements. Notes that , in order for locational TUOS charges to be recovered on the basis of customers' proportionate use of network assets in the adjoining region, TNSPs would need to calculate their load export charge and then redo theIRTCcalculations again after they receive export load charges from adjoining regions. This will result in an iterative process that ends only when all TNSPs resolve theIRTCprices in light of all other TNSPs' cascading load export charges. A practical solution will need to be identified in the testing and assessment process.	The Commission considers that by requiring the AER to amend the pricing methodology guidelines and to require TNSPs to amend their pricing methodologies, implementation issues would be able to be clarified. With respect to the timetable for the derivation and publication of distributor tariffs, the Commission considers that where possible, TNSPs should share up-to-date estimates with DNSPs.
EnergyAustralia (p. 2)	The proposal will introduce a greater level of price uncertainty, both initially and on an ongoing basis. To address this issue, considers that the publication date for inter-regional transmission charges should be 15 April of each regulatory year which would allow DNSPs to provide sufficient notice to customers of likely changes to prices in the forthcoming year.	As above.

Stakeholder	Issue	AEMC response given in first draft determination
EnergyAustralia (p. 7)	In the likely event that the price impacts arising from changes to the TUOS allocation approach are material, a degree of prescription on the cost allocation approaches used by individual TNSPs will be necessary. The Rules should also specify the types of assets to be included in the cost allocation.	The Commission considers that the AER's pricing methodology guidelines should clarify the types of assets that should be included, which would be consistent with the current provisions under the Rules.
EnergyAustralia (p. 10)	The AER's existing transmission pricing methodology guidelines do not appear to require modification to enable the recovery of inter-regional TUOS charges.	As discussed in sections 5.4.3 and 6.4.3 and noted above, the AER will be required to amend its pricing methodology guidelines.
EnergyAustralia	Noted that transitional provisions for the introduction of inter-regional transmission charging could be implemented at the transmission level, at the distribution level, or some combination of the two. Their interaction with existing pricing constraints for both transmission and distribution charges will also need careful consideration, to ensure that: (1) the impacts on the transmission and distribution connected customers are balanced; and (2) each TNSP or DNSP is not prevented from recovering the regulated revenue for its prescribed services.	The Commission notes that as the load export charge would be recovered from customers through the existing components of the prescribed transmission service charges, a new category of charges would not be created in terms of the amounts to be recovered by DNSPs. For this reason, DNSPs and retailers should be able to pass through these costs to the same extent as existing network charges are passed through. With respect to ensuring that the impacts on transmission and distribution connected customers are balanced, the Commission notes that the locational component of the load export charge is based on proportionate use of the transmission network, as discussed in section 5.4.3.
Other issues		
Gallaugher & Associates (p. 2)	Suggests that the proposal as presented is overly prescriptive. Considers an alternative would be to simply obligate the NTP to prepare and publish a methodology for quantifying the charges in accordance with some limited but quite well defined objectives, and to prepare, publish and administer operating	The Commission has taken into consideration the requirement to achieve an appropriate balance between the level of prescription under the Rules and the ability for the AER to establish guidelines to assist with the implementation of the load export charge. This is discussed in section 5.4.3.

Stakeholder	Issue	AEMC response given in first draft determination
	procedures for its implementation. In this way the interregional charges would all be determined on a consistent basis across all interconnectors.	
Gallaugher & Associates (p. 2)	The proposal will at best only marginally enhance achievement of the NEO. Considers that given the gross inadequacies of existing transmission regulatory and pricing arrangements in the NEM from an economic efficiency standpoint, it is not sensible to base one's entire argument for any inter-regional network charging proposal including this one around the question of economic efficiency and the NEO.	The factors that must be taken into consideration in any Rule change process is set out under the NEL. These requirements and the Commission's consideration of them are set out in Chapter 2.
Gallaugher & Associates (pp. 2-3)	The Consultation Paper should have included information on the potential impact of the proposal on existing transmission cost allocations and TUOS charges in each of the NEM regions. Considers that when quantitative data is considered it will show that inter-regional transmission charging is quite immaterial and not worthy of the amount of time and attention it has already attracted and will continue to attract until it is resolved.	As discussed above, the Commission notes that TNSPs, including AEMO in its capacity as a TNSP in Victoria, have undertaken modelling of the potential impacts of the load export charge on the redistribution of transmission charges. Consideration of the modelling outcomes are discussed in section 7.4.
Hydro Tasmania (p. 2)	Supportive of the request for the public disclosure of an assessment of the magnitude of net inter-regional payments based on historical network flows. However considers it would be unwise to assume that the historical flows will be a reliable guide to future performance, given the projected large growth in renewables in South Australia and the untapped wind energy potential in Tasmania.	As discussed above, modelling outcomes are outlined in section 7.4.
Gallaugher &	The Consultation Paper should have disclosed in quantitative terms what in fact has occurred since	The Commission notes the comments made and consideration of

Stakeholder	Issue	AEMC response given in first draft determination
Associates (p. 3)	NEM commencement on each interconnector in terms of energy flows, inter-jurisdictional payments; interconnector residue payments and settlement proceeds.	these issues are set out in section 7.4.
Hydro Tasmania (p. 2)	It would probably be more pertinent for an assessment to be provided on the basis of a forward-looking view but recognising that a degree of uncertainty will always surround projected system demand, generation location and consequent power flows. The materiality of net inter-regional payments may be low today but is is unlikely to remain so.	The Commission notes the comment made and notes that if changes in inter-regional flows occur in the future then it would be expected that the load export charges would be reflective of the changing utilisation of inter-regional transmission assets.
MEU (p. 3)	There are higher priority issues that need reviewing with respect to the transmission revenue and pricing regulatory framework. Concerns over the potential in the incidence of blackouts and brownouts in South Australia indicated in the CRA modelling for the AEMC Climate Change Review have not been addressed as the AEMC's final report was silent on this issue.	The comments are noted.
MEU (p. 5)	Despite the amendments to Chapter 6A of the Rules there has been almost no investment in increasing inter-regional electricity flow capability. Considers that the causes of this lack of investment in inter-regional transmission is a much higher order issue for the NEM than this Rule change request which merely allocates costs between customers.	The comments are noted. Transmission Frameworks Review will be examining a broad range of issues. It is noted that the Commission had published an Issues Paper for this review and is currently in the processes of reviewing the submissions received.
MEU (p. 19)	The MEU has long been a supporter of the view that justification of interconnector augmentation should include the benefit customers get from the greater competition between generators that results from this investment. The MEU considers that its view has been	The Commission notes that generators do contribute to transmission charges through prescribed entry charges. In addition, as noted above, the Transmission Frameworks Review will also include consideration of the broader framework.

Stakeholder	Issue	AEMC response given in first draft determination
	denied by the AEMC on the basis that to incorporate such in the regulatory test does not provide a net benefit to the market but it is a "transfer of wealth" between generators and customers. The MEU considers that this is inconsistent with the fact that as customers pay for transmission services, they should not have to share the benefit of the investment with generators.	
MEU (p. 20)	The AEMC has made no attempt to quantify the benefit the consumer in the importing region gets from using the assets in the exporting region, but assumes that they will exceed the also unquantified cost to use the assets in the exporting region. It is axiomatic in the Rules that a consumer should not be required to pay more for a service than the benefit it receives; therefore if the cost of the service exceeds the benefit a consumer gets, then it should not pay more than the value of the benefit it receives.	Modelling results are discussed in section 7.4.
AEMO (p. 7)	Unsure what meaning the proposed definition of prescribed TUOS services is attempting to convey but assume that it is trying to include benefits accruing to regions that are connected to the original region by an intervening region(s). If this is indeed the intention, it should probably be made more explicit in order to remove potential ambiguity.	The Commission notes that the underlying concept for the load export charge is that adjoining regions should be treated in the same way as customers within the region. For this reason, the definition of prescribed TUOS services has been expanded, consistent with the existing definition, so that TNSPs from the adjoining region are treated in the same way as connection points within the region.
EnergyAustralia (pp. 3-4)	Regional interconnections comprise lengthy, high capacity, high cost transmission assets connecting remote generators to jurisdictional interfaces. However, under the inter-regional TUOS proposal, generators do not pay charges for their use of the capacity of shared network assets. Generators in the	The Commission notes that these related issues will be further considered under the Transmission Frameworks Review.

Stakeholder	Issue	AEMC response given in first draft determination
	exporting jurisdiction can make free use of these assets and the entire cost of the assets be borne by the downstream customers in the importing region.	

Discussion paper

Stakeholder	Issue	AEMC Response
MEU	Because the inter-regional charge is levied purely as a transmission charge and does not reflect the delivered costs to customers, competitive neutrality between all parts of the supply change is put at risk. (P4)	The rule change is limited to transmission charging and so broader issues of costs and pricing are not addressed. However, it is not considered that the rule change puts competitive neutrality at risk.
	Whilst satisfying cost-reflectivity appears reasonable, net benefits are questionable, given the issues and complexities involved. (p5)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.
	Reliability is improved by interconnection. Thus a region which commonly exports but imports for short periods of time could get a significant benefit. Under all options that reflect the volumes of flows as the basis for charging, an outcome might be that an exporting region would receive a significant benefit which it does not pay for. (P4)	If spin-off benefits can be provided at no additional cost there is no reason to charge for them. Indeed, doing so could reduce allocative efficiency.
	Introducing an inter-regional charge will not result in the lowest cost for customers as local generation might give a lower cost to customers than imported power when the inter-regional charge is added (P4) IRTC does not affect	IRTC does not affect generation dispatch, which remains geared to providing energy to customers at lowest cost.

Stakeholder	Issue	AEMC Response
	generation dispatch, which remains geared to providing energy to customers at lowest cost.	
	customers will have little ability to change their behaviour because their investment costs are sunk and the only effect they can make is to reduce their demand which might not affect the amount of imported power at all (P4)	It is acknowledged the behavioural change caused by IRTC may be modest, but that should be sufficient to provide benefits that outweigh the implementation costs.
	Price signals are intended to change the behaviour of the party most able to manage the risk, yet the inter-regional charge is a cost to customers which have little ability to manage or mitigate the risks and costs. (P4)	The Commision notes that all customers have some potential to modify their consumption in response to changing electricity prices.
	An IRTC charge needs to reflect basic actualities. For example: the use of Victorian assets by Tasmanian customers is small; Victorian generation is closer to the Vic-NSW border than NSW generation, so Victoria will pay a net IRTCcharge to NSW even when interconnector flows are symmetrical. (P4)	Since the IRTC is based on the same CRNP method as is used intra-regionally, the IRTC should reflect outcomes in a similar way to existing intra-regional TUOS charges.
	Perverse and inequitable outcomes are still likely even with the new approaches to the inter-regional charge (p4)	Although there could be some perverse outcomes, the modelling undertaken suggests the IRTC are fair and reasonable.
	Any export charge does not impinge on generator location decisions which have a major impact on the size of the export charge (p4)	Introducing generator charges for IRTC would result in a significant increase in the cost of implementation for a minor part of revenue recovery.
	By implementing a load export charge through transmission costs that generators do not see, less efficient locational signals are provided to	Introducing generator charges for IRTC would result in a significant increase in the cost of implementation for a minor part of revenue

Stakeholder	Issue	AEMC Response
	generators resulting in higher overall costs (p4)	recovery
	If prices show significant variability year on year, then the price signal will not improve locational decisions of generators and customers (p4)	Agreed. Modelling indicates that the CRNP variant defined in the second draft rule has relatively low year-on-year variability.
	Variability in costs is a major concern in regions that have a large degree of weather risk (eg Tasmania in drought conditions) (p5)	Whilst weather variations may cause some variability in IRTC, these are likely to be small compared to associated variations in wholesale prices.
	Where there are two interconnectors, the actuality of the flows can be perverse, raising complexities that impinge directly on the issue of reliability and generator locations (p4)	This appears to be a dispatch issue which is beyond the scope of the rule change.
	Any changes in usage that is caused by the introduction of inter-regional charging will impact the spot market and this needs to be taken into account (p4)	Impact on the spot market will be small and unlikely to be material.
	Options considered requiring a normalisation of cost allocations in all region might not be in the interests of customers. (p4)	The second draft rules does not require any change to cost allocation (ie asset valuation) methods.
	The nominated new approaches are not supported by quantitative analysis and modelling to ascertain the economic costs and benefits. (P5)	It is expected that the administrative costs will be modest and likely to be outweighed by the benefits
AER	The AER suggests that the AEMC also consider the costs and benefits of the proposed model relative to a “do nothing” option (p1)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.

Stakeholder	Issue	AEMC Response
	The AER prefers NEM-wide CRNP [as it is most cost-reflective]…However, should the obstacles to implementing this option within a reasonable timeframe prove insurmountable, then the AER considers that a simpler option, such as MLEC, is likely to constitute an improvement on the status quo (p1)	Agreed. It is considered that the extra costs of administering NEM-wide CRNP (compared to MLEC) would outweigh the incremental benefits, at least in the short-term.
	Changes to the TNSPs' pricing methodologies have he potential to cause price shocks to customers. By decoupling consideration of inter- and intra-regional transmission charging, customers may be exposed to two sets of price shocks in relatively short succession (p2)	Modelling suggests that the price impact of the IRTC will be modest.
	The inclusion of postage stamped components is likely to undermine the intent of the policy by obscuring the locational signals associated with inter-regional charges (p1)	The draft rule excludes postage stamp charges from the calculation of IRTC.
AEMO	We think that the options proposed [MLEC and NEM-wide CRNP] risk creating complexity without necessarily advancing the [pricing] objectives. (p3)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.
	Interconnector investment can depend on a number of factors but will usually have more to do with gaining access to more efficient reserves of generation from neighbouring regions than a region can provide on its own. (p1)	Sharing of reserves will be reflected in interconnector flows and hence in MLEC prices.
	Ideally [an efficient] price would be calculated on a prospective basis, recognising the future costs	Agreed. This is the reason for choosing CRNP for IRTC.

Stakeholder	Issue	AEMC Response
	that will be incurred as a result of additional load at a point on the network. Given the difficulties and vagaries of this theoretical approach, we agree that in relation to ordinary customer load points, the cost reflective network pricing approach adopted is a reasonable proxy. (P1)	
	If this price signal is effective, it will reward customers whose behaviour contributes to deferring network investments. Therefore, by designing a regime that properly identifies the usage in relation to network capacity, and pricing accordingly, it will also indirectly inform the network investment required to accommodate those users (p1)	Agreed
	Having a "net" load export charge at the border might provide unreliable and confusing investment signals. When, over the course of a year you have flows going in opposite directions, you are left with a net charge that does not necessarily inform investment needs (p1)	If there are flows in both directions, the net IRTC is likely to be small and so little different to the status quo. The IRTC is most important when flows are predominantly in one direction, meaning that the status quo is inefficient.
	Therefore, [MLEC] is not suited to the Victorian and NSW regions because it does not allow those regions to charge other regions for energy wheeled across its network. In this respect, [NEM-wide CRNP], despite its complexity might represent a better solution. (p3)	The impacts of demand on non-adjoining regions is likely to be small and the value of pricing that impact is not sufficient to offset the higher administrative costs of NEM-wide CRNP.
	We believe that [MLEC and NEM-wide CRNP] create similar issues to the original IRTCproposal. While some methodologies are standardised, there is still the ability to	In the second draft rule, all assets are included in the CRNP run used for IRTCand the method is essentially standardised.

Stakeholder	Issue	AEMC Response
	differentiate approaches of determining which assets do and do not contribute to inter-regional flows. (p3)	
	Ultimately, classifying assets that are used for, or contribute to, inter-regional flows is a variable that each CNSP will need to interpret and apply to the transmission assets within its region. This can, particularly over time create inconsistencies with their regional neighbours (p3)	In the second draft rule, assets are not explicitly classified. All assets are included in the CRNP run used to calculate MLECs.
	[under NEM-wide pricing] if a coincident peak method of determining cost allocations were adopted, there would need to be some agreed way of establishing meaningful peak periods common to the entire NEM (03)	Agreed. It may be difficult to establish such a definition. That is one reason why the “365C” approach is required under the draft rule, rather than a 10-day approach.
	We think that [NEM-wide CRNP pricing] is a better option because not only would this approach ensure that each load point in the NEM is treated consistently, it dispenses with the necessity of having to treat interconnectors as notional connection points at the regions’ borders. (p2)	NEM-wide CRNP is preferred in principle for this reason. However, it has some practical difficulties which would make it costly to implement and administer solely for IRTC.
	[Under a LEC method] differing valuation and apportionment methodologies between those regions, will cause customers to face unclear and inconsistent locational pricing signals as each region charges load export charges based on differing apportionment methods from their neighbours (p2)	Agreed.

Stakeholder	Issue	AEMC Response
	The difficulty that [cost sharing] faces is that because usually, most of the benefit from interconnectors flows to one region, obtaining agreement to contribute to the costs from the region that enjoys the lesser benefits might prove to be a challenge (p2)	Agreed.
	A single TUOS pricing authority would be the best method of maintaining an efficient inter-regional transmission pricing regime because it is able to align cost allocations for all transmission assets in the NEM more consistently and ensure that consistency is maintained for the longer term. (p2)	Aligning cost allocations is likely to be costly and would not be expected to materially change MLEC levels.
Department of Primary Industry	DPI has a different understanding of how the various elements of economic efficiency are defined and how they should be applied to the issue of inter-regional transmission pricing than that set out in the Discussion Paper (p4)	The AEMC notes the DPI's comments.
	The Discussion Paper argues that while transmission charging should encourage both the so called static efficiency and dynamic efficiency, that the unique characteristics of transmission results in conflicts between them. DPI does not agree with this perspective (p7)	The AEMC notes the DPI's comments.
	DPI notes the Discussion Paper's argument that an efficient charging regime would require trade-offs between allocative and dynamic efficiency. DPI disagrees with this analysis and notes that efficient markets are in effect markets	Pricing above short-run cost reduces short-run efficiency but promotes long-run efficiency. The economic theoretical distinction between the short-run (using existing capital) and the long-run (allowing for capital investment) is uncontentious. To merge these two timescales into "over time" is not helpful to the economic analysis.

Stakeholder	Issue	AEMC Response
	that are productively (p11) and allocatively efficient over time.	
	However, when a strict use of an appropriate test for cross-subsidies is applied (cost of interconnected network versus stand-alone networks), it is unlikely that they would exist for existing networks. (p2)	It is acknowledged that this may be true based on a strict economic definition of cross-subsidy. However, the existence of cross-subsidies is not necessary to create impediments to inter-regional expansion
	In essence, intra-regional transmission investments within each region have been largely undertaken to support intra-regional transmission capability (p7)	Agreed. This is due to impediments embodied in existing transmission charging arrangements, which the rule change is seeking to remove
	One of the key rationales on which the proposed draft rule change is based, that the existing arrangements result in implicit cross-subsidies, is not substantiated by the facts and the manner in which intra-regional transmission systems have been planned and constructed historically. (p7)	The Commission views that there are other benefits derived from an IRTC that are not linked to removal of cross subsidies.
	DPI does not support the modified load export charge or NEM-wide CRNP charge as the assets to be included do not reflect the true incremental cost of assets involved in establishing inter-regional transfer when compared with the cost of providing stand-alone regional networks (the true measure of any cross subsidy); . (P14)	Since network planning is not actually done on a regional standalone basis, the hypothetical costs of doing so are irrelevant to efficient pricing. Efficient prices should signal future costs under the actual planning regime.
	The regulatory arrangements promote network expansion independently of decisions by customers to connect. The five year regulatory pricing decisions tend to be based on broad estimates of load growth with transmission	Network expansion is predicated on the RIT-T, which does take into account current and projected demand

Stakeholder	Issue	AEMC Response
	development designed to meet those estimates (p10)	
	DPI considers that there is no economic benefit in using LRMC pricing linked to network usage for existing customers as the locational decision has been made and pricing usage above congestion costs will lead to a loss of allocative efficiency. In relation to potential customers, some variation in fixed costs to reflect expansion costs at different locations may be warranted. (p10)	While the locational decision has been made it is not the relevant decision that a customer can make in a CRNP approach to TNSP pricing.
	DPI does not support the modified load export or NEM-wide CRNP charge as it proposes charging on an energy flow usage basis, which may be misinterpreted in a manner that is inconsistent with the benefits and rationale for transmission investments. (P14)	It is not expected that the use of a CRNP method will be interpreted as anything other than an extension of intra-regional TUOS pricing to inter-regional flows.
	DPI considers that for existing networks, only cross-subsidies that exist through the application of a strict cross-subsidy test should be included as assets for the inter-regional transmission charge. (p2)	The Commission views that there are other benefits derived from an IRTC that are not linked to removal of cross subsidies.
	DPI considers only new assets that demonstrably enhance the capacity of inter-regional transfers, including any investment to maintain transfer capacity that would otherwise decline, should be included in the asset base for the inter-regional transmission charging regime (p2)	The Commission addresses this point in section 13

Stakeholder	Issue	AEMC Response
	DPI does not support the modified load export charge or NEM-wide CRNP charge as it does not specifically limit charging to assets that are demonstrably involved in transferring electricity between regions . (P14)	Any assets whose costs are allocated inter-regionally by CRNP are "inter-regional assets" in that they are used in inter-regional transfers.
	DPI does not support the modified load export charge or NEM-wide CRNP charge as it does not differentiate between investment to support enhanced intra-regional transmission capability and inter-regional transmission capability . (P14)	Any assets whose costs are allocated inter-regionally by CRNP are "inter-regional assets" in that they are used in inter-regional transfers. There is no clear distinction between "inter-regional" assets and "intra-regional" assets. Many assets will play a dual role.
	DPI does not support the modified load export charge or NEM-wide CRNP charge as it does not differentiate between existing sunk investments and future investments; . (P14)	The Commission addresses this point in section 13
	The short run marginal price of transmission (congestion cost) should be retained as the only form of locational price signal for existing network users. The short run marginal price plus any fixed costs (allocated as set out below) would provide efficient signals to potential users. (p12)	The AEMC notes the DPI's comments
	Using the non-locational and common service charges for existing networks in addition to the SRMC to send locational signals will result in excessive prices, which would lead to allocative inefficiency. Hence any application of cost-reflective pricing should avoid allocating the non-locational and common service charges on a locational basis. (p6)	Agreed. The draft rule excludes postage stamp charges from the calculation of the IRTC

Stakeholder	Issue	AEMC Response
	DPI does not support the modified load export or NEM-wide CRNP charge as it proposes to incorporate components of non-locational and common service charges which will reduce allocative and dynamic efficiency; and,)	The draft rule excludes postage stamp charges from the calculation of the IRTC.
	As changes in the type and location of the generating mix will cause most of the changes in generation patterns and network flows (creating the need to reconfigure and expand existing networks) and as generators do not contribute towards the recovery of fixed costs, the inter-regional transmission charge would appear to have little economic merit (as it would not be levied on the participants driving the changes) (p10-11)	The AEMC argument is that changes in the generation pattern are changing the flows on interconnectors and TUOS pricing needs to be reformed to reflect this change. Introducing generator charges for IRTC would result in a significant increase in the cost of implementation for a minor part of revenue recovery.
Grid Australia	GA submits that the Commission would find it difficult to demonstrate that extending the existing transmission pricing methods to inter-regional transmission pricing would in fact generate net benefits in accordance with the NEO (P8)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.
	It is unclear to GA how a “causer or beneficiary pays” concept relates to marginal cost pricing (p7)	Agreed. This determination refers simply to “pricing efficiency”
	Current transmission pricing methodologies are at best approximations to marginal cost pricing (p8)	Agreed. Given lumpy investment it is difficult to exactly measure “marginal cost” for transmission.
	Inconsistencies between replacement cost	Agreed. This is one of the major reasons why the second draft rule

Stakeholder	Issue	AEMC Response
	models present a fundamental obstacle to the [NEM-wide TUOS] (p7)	uses an MLEC method, rather than NEM-wide CRNP
	As noted in previous submissions, inconsistencies between replacement cost models used by TNSPs are to be expected but do not impact on the calculation of a load export charge at the boundary of a region (p6)	Agreed. This means that the administrative costs of the MLEC method are modest.
	The measure of demand used for the calculation of prices only affects customers within a region and is not expected to impact on the calculation of inter-regional charges (p6)	Agreed. The second draft rule does not require demand measures.
	While the modified CRNP methodology is slightly more complex than standard there is limited scope for subjectivity in the calculation of line ratings and utilisation factors (p4)	Agreed. The main concern around the modified CRNP method is the administrative costs for those TNSPs which do not currently use it.
	The modified CRNP methodologies adopted by both ElectraNet and Transend deliver appropriate price signals to those customers on lightly loaded radial lines. It does not materially impact on the prices within the meshed network or points of connection to adjacent regions. (p4)	Agreed. That is why the second draft rule requires use of the standard CRNP. Although it may be appropriate for TNSPs currently using modified CRNP to also use it for calculating MLECs, transparency is improved (and administrative costs not significantly increased) if all TNSPs use standard CRNP.
	AEMO's [10E] methodology doesn't capture the conditions necessary for a credible inter-regional charging methodology (p5)	Agreed. During regional system peak, interconnectors are likely to be importing and so calculated MLECs would be too low.
	GA considers that the [10E] method is inappropriate as a mechanism for sending demand side participation signals	Agreed

Stakeholder	Issue	AEMC Response
	The flows on interconnectors at times of system peak are not necessarily consistent with those expected to drive network investment (p5)	Agreed. That is one reason why the “365C” approach is required under the draft rule, rather than a “system peak” approach.
	With the exception [of 10E vs 365C] there is no evidence that the minor differences between intra-regional pricing methodologies will impact materially on the original load export charge (p3)	The modelling would appear to confirm this view. However, since the definition of peak period (10E or 365C) is material, a LEC would give rise to non-transparent pricing between Victoria (that uses 10E) and other regions (that use 365C).
	“recovers the costs of an existing network” implies the full inclusions of sunk costs in prices on all occasions (p7)	That was not the intended meaning.
	GA remains firmly of the view that the load export charge should be based on the locational component of prescribed transmission services only. (p5)	The draft rule excludes postage stamp charges from the calculation of the IRTC.
	There is no obvious benefit in pricing sunk costs at the boundary between regions (p8)	Noted.
	Priority should be given to ensuring that most TNSPs would have the option of amending their pricing methodologies to the extent required to remove the requirement for a two-step CRNP [method] (p8)	The AEMC agrees that there is no inherent benefit from pursuing a two step methodology. However, it is unclear how the desired pricing outcome can be achieved without requiring a separate calculation of the IRTC.
	[The rules] should allow Victoria to maintain its [10E] method for intra-regional pricing and do a second run based on a methodology consistent with the national principles, while all other TNSPs could…implement inter-regional charging via relatively minor amendments to their existing	The second draft rule does not seek to amend the method used by TNSPs for intra-regional transmission pricing.

Stakeholder	Issue	AEMC Response
	pricing methodologies (p9)	
	The new options appear to be administratively complex to implement as they represent a shift away from the existing methodology TNSPs use for their intra-regional charging. This will add further complexity to an already complex pricing regime which will not aid transparency to customers. In addition it can be expected to take longer to implement the new options. (p3)	It is anticipated that the additional administrative costs of MLEC (compared to LEC) will be very modest. It is acknowledged that the different approaches to intra-regional and inter-regional TUOS pricing will create some additional complexity and loss of transparency.
	GA considers that the Commission should maintain the current principles-based approach to pricing in the Rules (p8)	The Commission has maintained the pricing principles for transmission charging.
	The degree to which the Commission wishes to deal with the pricing of sunk costs could also be important in deciding between the CRNP based and cost sharing options(p8)	The Commissions approach to pricing sunk costs for IRTC purposes is the same as adopted for intra-regional pricing.
	Principles in the Rules should be limited to (a) choice of load conditions (b) quarantining from each other under/over recoveries of intra-regional and inter-regional charges (c) ensuring that SRA proceeds only benefit customers in the region intended (d) ensuring that only the prescribed locational component is to be charged across borders (p9)	The Commission has sought to isolate the impact of IRTC from the other aspects of Transmission pricing such as SRA proceeds.
	The principle defining the [MLEC] methodology should be defined in the rules with the detail to be defined in the pricing methodology guideline and the pricing methodologies in consultation	Including the detail in the second draft rule makes it clear for all stakeholders the approach the TNSP must adopt.

Stakeholder	Issue	AEMC Response
	with the AER. `(P15)	
Intergen	IGA considers that broadening the consideration of the Discussion Paper to include non-prescribed services is relevant to the overall efficiency of any proposed regional transmission charging regime and methodology (p3)	Unregulated services fall outside the scope of the proposed rule change.
	IGA submits that any new rule associated with inter-regional transmission charging should be applied to both new and existing infrastructure (including unregulated assets) (p1)	While the Commission has included existing assets within the operation of the second draft rule, unregulated services fall outside the scope of the proposed rule change.
	IGA submits that there may be further opportunities to improve cost-reflecting network pricing by expanding the scope to include negotiated or unregulated services (p1)	Unregulated services fall outside the scope of the proposed rule change.
AGL Energy, Alinta Energy, International Power GDF-Suez, LYMMCo	This analysis of benefits relevant to each purpose could be derived from the analysis under the RIT-T process, or from any alternative analysis of benefits that might be applied. (p4)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs.
	Any IRTCcharge should be on going and stable unless and until a network planning decision within the region re-allocates part or all of the relevant network capability to another purpose i.e. under-utilisation, of itself, should not lead to re-allocation of costs, (p1)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs.
	the superior methodology of allocating cost, ex ante, on the basis of causation, is not available for most transmission investments within a	There is no reason why this could be applied within a reason, but also no reason to apply it, given that efficient pricing is to signal future costs, not allocate historical costs

Stakeholder	Issue	AEMC Response
	region (P5)	
	We propose that any IRTCcharge should be based on the true causation of cost in the transmission network, namely the decision to invest in new transmission assets, and should apply where the justification of new investment is based, in part or entirely, on the expectation of persistent energy flows from or through the constructing region, (p1)	Expectation of future flows must be predicated on existing consumption patterns and interconnector use. Thus, charging based on this use is consistent with the expressed "causer-pays" philosophy.
	We accept that ex-post cost allocation (such as CRNP) is unavoidable for many transmission costs within a region. This situation is one where charges based on causation are beyond practical reach and a plausible locational cost signal is the best that can be achieved (p3)	There is no significant distinction between inter-regional and intra-regional in this respect. For this reason, CRNP is considered to be an efficient pricing method for IRTC.
	The cases where ex-post cost allocation can be avoided include investment for new generator access, new large customer supplies, and interconnectors. In each of these cases, the cause of the cost will be clear at the time that the investment decision is made. (P3)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs. An "ex ante" approach cannot signal future costs as prices will not respond to changing consumption patterns.
	Since the actual costs of the transmission network are determined on an ex-ante basis, we contend that in all those cases where cost can be allocated on the same ex-ante basis, it should be. (p3)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs. An "ex ante" approach cannot signal future costs as prices will not respond to changing consumption patterns.
	Where assets were built as Scheduled Network Services, and subsequently converted to regulated interconnectors, the AER has had the	The purpose of efficient pricing is to signal future costs, not to allocate historical costs

Stakeholder	Issue	AEMC Response
	opportunity to divide the costs appropriately between market regions (p3)	
	The costs of the existing network are already being recovered. The allocation of costs between the regions is generally based on the original purposes for the investment. As discussed above, we believe that there would be no benefit in relation to the National Electricity Objective in reallocating these sunk costs. (P7)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs.
	The assessment criteria of “provides a signal for future investment” should be secondary to “administrative efficiency”, “transparency” and “stability and regulatory certainty, including cost impacts”. (P7)	Agreed. The “investment signal” arises only indirectly as a consequence of demand response to the TUOS prices.
	We do not support any IRTCcharge based on the cost of existing transmission assets (P1)	The cost of existing assets embedded in the CRNP method is a proxy for the cost of future investment which the IRTC signal.
	We submit that there is no justification in terms of the National Electricity Objective in now undoing these past decisions, by re-allocating these historical and sunk costs. (p2)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs. If the demand pattern changes then TUOS prices should change.
	This use is almost entirely beyond control as power flows are determined by physics, not by intentions. (p4)	The asset use is determined by demand, which is under the control of the consumer.
	As we have noted earlier, such IR transmission charges should be independent of the actual power flows on the Network (p5)	Actual power flows indicate the level of utilisation of existing assets which, in turn, indicates the likely need for, and cost of, transmission expansion.

Stakeholder	Issue	AEMC Response
	The share of the asset cost previously supported by the IRTCcharge would then be allocated in accordance with the new use of the capacity, for example to a generator if it now supports a new generator access. (P5)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs
	We note that opportunistic usage of the network for purposes other than those originally envisaged has no material impact on capital charges, operational costs or maintenance costs. (P7)	Agreed. But the TUOS charges are not intended to reflect the cost of using the existing network but rather the expected future cost of expansion based on current and projected use.
	We are proposing that only new inter-connector assets are included in the IRTCcharge, and have excluded sunk charges because in addition to the reasons given above; this has the benefit of reducing the price impact of the IRTCcharge (P7)	By definition, any assets whose costs are allocated inter-regionally by CRNP are “inter-regional assets” in that they are used in inter-regional transfers. Modelling indicates that price impacts under the draft rule are reasonable and do not need to be reduced.
	The short-run marginal costs of transmission are not directly met by TNSPs, are uncertain and often perverse in their impact on a TNSP and we therefore contend that no attempt should be made to include them in an IRTCcharge (p2)	Agreed. Only transmission asset costs are included in the second draft rule.
	We note that these [IRTCcharges] have no locational significance in either the sending or receiving region, and therefore expect that they would apply to costs recovered on a “postage stamp” basis on both regions (P5)	The Commission is of the view that recovery of these charges through the locational component improves the pricing signal sent to customers. While recognising that this signal is weakened by combining it with the intra-regional charge it is still an improvement on a postage stamp basis.
Office of energy planning and Conservation (Tasmania)	There are difficulties though in including some existing assets: such as Basslink (P6)	The rule change applies only to regulated network assets. Basslink is unregulated.

Stakeholder	Issue	AEMC Response
	some form of smoothing mechanism needs to be introduced such that charges do not vary significantly and unpredictably from year to year. (P2)	Modelling suggests that annual variations in IRTC are modest and so a smoothing mechanism is not required.
	It is not clear to what extent non-adjoining regions utilise each other's transmission assets. This needs to be modelled to determine to what extent the issue is material. If it is significant then option 3 would become a strong candidate for being the preferable option. (P5)	It is believed that the impacts of demand on non-adjoining regions is small and the value of pricing that impact is not sufficient to offset the higher administrative costs of NEM-wide CRNP.
	If cost-sharing or NEM-wide CRNP becomes the preferred option, asset valuation will need to be consistent for those methodologies to be applied. Asset valuations are non-trivial exercises and it is important to avoid excessive work and duplication of effort.(P4)	Agreed. This is one of the major reasons why the draft rule uses an MLEC method, rather than NEM-wide CRNP
	While a standard CRNP may be easier to implement in a uniform manner, a modified CRNP provides better locational signalling and is therefore more aligned with driving efficient utilisation of the network.(p3)	Use of modified CRNP, rather than standard CRNP, would not materially change the level of MLECs but would impose significant cost to those TNSPs who do not currently use it.
	The 10 day system peak methodology may lead to volatility in locational price if major industrial customers change their behaviours. (p4)	Agreed. Modelling results would seem to confirm this volatility.
	Inter-regional transmission charges must not include costs not directly relevant to the provision of transmission services in the adjoining jurisdiction (p2)	The second draft rule excludes postage stamp charges from the calculation of IRTC.

Stakeholder	Issue	AEMC Response
	The modified LEC would be preferable to the original LEC as it is based on application of a consistent methodology. This is on the proviso that the benefits of carrying out an additional uniform national CRNP methodology outweigh the additional administrative costs of doing so (P4)	It is anticipated that the additional administrative costs of MLEC (compared to LEC) will be very modest
	Customers / stakeholders may find differences in methodology between intra and inter regional charging confusing, adding to an already complex system of calculating prescribed transmission charges. (P5)	It is acknowledged that the different approaches to intra-regional and inter-regional TUOS pricing will create some additional complexity and loss of transparency. However, the scope of the rule change is restricted to inter-regional charging.
	cost sharing represents a considerable departure in methodology from existing intra-regional methodologies, and other proposed options for inter-regional charging. There is considerable merit in having consistency between the derivation of the inter-regional charge and the intra-regional charge. Having two different regimes adds complexity and raises questions as to why two regimes exist. (P6)	Agreed. There are no substantive differences between intra-regional and inter-regional transmission that would justify such different approaches to pricing the two services.
	The preferred option should be subject to extensive modelling over an extended time period (taking into account varying energy flow patterns between jurisdictions) before it becomes the final option. (P5)	Some modelling has been undertaken and a report published.
	TNSPs should not be required to negotiate / agree in isolation on any components of the methodology. Such negotiation / agreement	The common elements of the MLEC are set out in the second draft rule. For all other matters the AER is required to update its guideline.

Stakeholder	Issue	AEMC Response
	should be carried out on a nationally consistent basis and be overseen by an independent body, such as the AER. (p2)	
	it is more important to establish some form of inter-regional transmission pricing now even if not perfect rather than wait until a 'perfect' process can be developed. Any problems with the initial regime can always be addressed in a review after a few years. (p2)	Agreed
TruEnergy	The AEMC needs to be satisfied that this approach can be implemented and that its benefits exceed its costs. We believe that before any form of new pricing regime is introduced, the AEMC needs to be satisfied that the benefits of implementing that new regime should exceed its benefits. (p5)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.
	We acknowledge that the cost sharing option would be easier to implement compared with the other options given its simplicity of design. However, in providing a simple inter-regional transmission charging approach under this methodology, the price signalling to customers would be lost. In short, costs would be shared between TNSPs and not based on the proportionate use of the assets. (P4)	Agreed.
	However, we understand that a MLEC - which would recover inter-regional transmission charges on a bilateral basis - has one major shortcoming. And, that is that inter regional charges can only be levied on TNSPs in	Agreed. The NEM-wide CRNP method does not have this limitation, however the cost of implementing that approach would be significant.

Stakeholder	Issue	AEMC Response
	adjoining areas under a MLEC. (P3)	
	The inconsistent application of intra-regional TUOS in the NEM would raise serious questions regarding the efficiency of any inter-regional transmission tariff developed under a LEC (P2)	Agreed. This is why the second draft rule adopts the MLEC.

Modelling results

Stakeholder	Issue	AEMC Response
Private Generators	Supports the introduction of an IRTC	Noted
	Do not support an IRTC based on existing transmission assets	The Commission notes that the current intra-regional transmission charging method includes existing assets. To not include these assets in the IRTC introduces instability in charges and an inconsistency with the basic principles of the intra-regional charging approach.
	The IRTC should be based on the true causation of the cost in the transmission network, namely the decision to incest in a new transmission asset.	The Commission notes that the benefits that can be derived from an asset over time will change and that a CRNP based approach utilised in the intra-regional transmission charge already changes to reflect use of the assets rather than the basis on which they were constructed. The Commission is of the view that the IRTC should take into account the basis on which intra-regional transmission charges are determined. A more fundamental review of transmission charging is more appropriate to a broader review, such as the TFR..
	Any decision to make a network investment will lead to an IRTC should be reviewed by independent authority such as the AER	The AEMC note that the TNSPs are subject to the RIT-T regardless of whether the cost of that investment will be recovered intra-regionally or through an IRTC.

Stakeholder	Issue	AEMC Response
	Any IRTC should be on-going and stable unless and until a network planning decision within the region re-allocates part or all of the relevant network capability.	Stability of charges is just one relevant factor for consideration. The other aspects of the AEMC's assessment framework are outline in section 5 of this document.
	The IRTC should be recovered through the non locational charges.	Recovering the charges through the locational component of the intra-regional transmission charging method is more consistent with using the locational component of TUOS in the calculation of the IRTC.
	The short run marginal costs of transmission are not directly met by TNSPs, are uncertain and often perverse in their impact on a TNSP, and we therefore contend that no attempt should be made to include them in an IRTC.	All TNSPs costs are recovered through their pricing method. The IRTC seeks to extend this method to cover IRTC. It does not specifically seek to address or separate the issue into short-run or long run marginal costs.
Grid Australia	Limited opportunities for engagement in the modelling itself.	The AEMC notes that most TNSPs were contacted at least once in relation to the data collections process. Further, a sample set of results were provided to TNSPs for comment consistent with the AEMC's communication with them. The AEMC's consultant is know to all TNSPs as he is the author of the pricing model they use. The TNSPs were informed of the basis on which the modelling was to be undertaken. Despite being aware that modelling was being undertaken no attempt was made by TNSPs to seek further engagement with the AEMC or the AEMC's consultant beyond that engagement initiated by the AEMC.
	Agrees that for IRTC to be calculated at a regional level a consistent method for allocating charges between adjacent regions is required. This could be a consistent pricing method which could be overlaid on the existing arrangements or a consistent pricing method for all TNSPs in the NEM as proposed in the TFR.	Noted

Stakeholder	Issue	AEMC Response
	The modified CRNP method results used for the reports modelling of MLEC provides limited insight intot he application of the modified CRNP in the rules. Modelling should give an indication of the relative charges at the extremities of the network under a standard or modified approach.	The AEMC choose to pursure the standard CRNP for the MLEC because fo the significantly lower implementation costs. Grid Australia's observations have been passed on for consideration as part of the TFR.
	Should the Commission pursue a consistent national pricing regime under the TFR, a national approach to replacement cost valuation of the networks would be required.	Grid Australia's observations have been passed on for consideration as part of the TFR
	The use of 10 peak trading intervals is not supported by Grid Australia as it is ulikely to reveal the circumstances under which augmentation of network elements would contemplated as required under the rules.	Noted. The AEMC discusses the selection of measurement intervals in section 13.2 .
	Grid Australia understands the intent of this variation was to determine the flow on effects of a new major interconnector asset on charges to adjacent regions. A more robsut method would involve identifying an interconnector asset in each region and inflating its value.	New assets only was selected to be modelled reflecting concerns raised by some stakeholders that the IRTC should not apply to existing assets. The AEMC believed that it was appropriate to conduct analysis on an approach reflecting new assets only.
	Grid Australia supports the use of capacity mode in conjunction with teh full year of trading intervals. It is understood that the use of energy mode for large sample sizes tends to diminish the cost reflectivity of the method.	Agreed. The analysis of capacity or energy mode is outlined in section 13.3.
	Grid Australia is concerned that the AEMC has characterised the quality of the load data	The AEMC notes that most TNSPs were contacted at least once in relation to the data collections process. Further, a sample set of results

Stakeholder	Issue	AEMC Response
	provided as poor. It was expected that the data acceptance process would involve a high degree of collaboration between TNSPs and the consultant. It was not apparent that all issues identified in section 8 of the report were drawn to the attention of TNSPs.	were provided to TNSPs for comment consistent with the AEMC's communication with them. The AEMC's consultant is know to all TNSPs as he is the author of the pricing model they use. The TNSPs were informed of the basis on which the modelling was to be undertaken. Despite being aware that modelling was being undertaken no attempt was made by TNSPs to seek further engagement with the AEMC or the AEMC's consultant beyond that engagement initiated by the AEMC. The AEMC attempted to engage with TNSPs where data issues were identified. It was not the AEMC's intention to keep data validation and correction issues from TNSPs.
	Alignment of cost data with AEMO network model may significantly complicate the cost allocation process.	The AEMC is not requiring this as part of the IRTC second draft rule change.
	An IRTC should only be progressed only if there is no decision to implement national pricing under the TFR in the near term.	As the TFR is a review rather than a rule change any changes to the rules would be dependent on a rule change request being received and the AEMC undertaking a review of the rule change request. The timing and outcome of either of these aspects are uncertain. The Commission has determined the introduction of an IRTC is consistent with the NEO and second draft rule proposes the commencement of operation of the rule on 1 July 2014..
Energy Australia	The NEM wide CRNP was more likely to support the NEO.	The Commission has determined not to introduce a NEM wide CRNP because the current institutional arrangements are such that no independent organisation currently possesses the skill set to immediately be able to undertake responsibility for calculating the NEM wide CRNP.
Major Energy Users	Any changes in usage that is caused by the introduction of inter-regional charging will impact the spot market and this needs to be taken into account.	Any pricing method for transmission charges will have an indirect impact on the spot market given all participants in that market pay TUOS. It is the AEMC's position that the current arrangements are more distorting in that they do not align costs and benefits for the use of the transmission network if the beneficiary is in a different region to

Stakeholder	Issue	AEMC Response
		the TNSP incurring the cost.
	Introducing an inter-regional charge will not result in the lowest costs for customers as local generation might give a lower cost to customers than imported power.	The IRTC is about the recovery of cost that are incurred. The MEU 's comment seems more relevant to the decision on whether to augment the network rather than recover a cost that has already been incurred. The process for investment in TNSPs is beyond the scope of this rule change.
	customers have little ability to change their behaviour because their investment costs are sunk and the only effect they can make is to reduce their demand which might not affect the amount of imported power.	The introduction of the IRTC improves prices signals as it more accurately reflects the usage of the network.
	Reliability is improved by interconnection.	Noted. However, in introducing an inter-regional transmission charge the Commission had to consider costs of implementing a new arrangement as well as the benefits that would be derived from doing so. Trying to account for reliability increases subjectivity and complexity of any calculation method. The AEMC's assessment framework is outlined in section 5
	Where there are two interconnections the actuality of flows can be perverse, raising complexities that impinge directly on the issue of reliability and generator locations.	The modelling results show that some approaches to the IRTC, including the Commissions preferred approach, are stable across time.
	The inter-regional charge is a cost to customers which have little ability to manage or mitigate the risk and costs.	The IRTC does not change the revenue for TNSPs. So the IRTC is not a cost to customers as a group. It will increase costs to some customers while lowering costs to other customers based on their location and usage. Most importantly it does so in a way that better reflects the benefit that customers are currently deriving than the current arrangements.

Stakeholder	Issue	AEMC Response
	Options require a normalisation of cost allocations in all regions which might not be in the interests of customers because a different approach used in one region might better benefit customers in that region that the approach used in another region.	The AEMC has consulted broadly on this rule change. Stakeholders have overwhelming endorsed an approach to produce consistency across methodologies.
	Because the inter-regional charge is levieed purely as a transmission charge and does not reflect the delivered cost to customer, competitive neutrality between all parts of the supply chain is put at risk.	Improving price reflectivity improves the signals to all aspects of the market.
	Implementing a load export charge through transmission costs that generators do not see, less efficient location signals are provided to generators.	The current arrangements do not provide direct locational signals to generators. The introduction of an IRTC do not change these arrangements. Therefore, the Commission strongly disagrees with the MEU's suggestion that the IRTC will produce less efficient location signals for generators.
	For price signals to provide the outcome sough, there must be consistency in bother their development method and the actual prices.	Agreed. Transparency of operation and outcome are part of the AEMC's assessment framework.
	An inter-regional charge needs to reflect basic actualities.	The IRTC is trued up for differences between actual and estimated flows meaning that it reflects the actuality of the costs incurred by TNSPs and the flows on their network.
	Perverse and inequitable outcomes are still likely even with the new approaches to this inter--regional charge	The AEMC requests that the MEU provides some evidence to support this statement.
	The variability in costs is also a major concern in regions that have a large degree of weather risk.	Regulatory stability and outcome transparency are both part of the AEMC's assessment framework. These assessment framework is

Stakeholder	Issue	AEMC Response
		outlined in section 5
	Without extensive modelling and analysis it is difficult to fully evaluate approaches.	The AEMC has published the results of all the modelling that it has undertaken, this shows the extent of inter-regional transmission charges. Stakeholder's should be able to evaluate the different options under consideration by the AEMC.
	The MEU questions the benefits in the short or long term given the issues and complexities.	The AEMC's basis for its determination that the preferable draft rule better meets the NEO are set out in the second draft determination.
	It is not made clear as to the basis for the modelling.	The basis for the modelling is clearly spelt out in Rolib Pty Ltd's report on the AEMC website.
	The modelling report states that the IRTC should be based on capacity transfer. Yet it does not make it clear as to what capacities have been used.	The report refers to utilising the capacity (or peak) approach to element use
	This assessment makes setting a LEC somewhat problematical should the charge be based on the annual usage in a particular year or should they be based on the cost of the assets that allow the flows as and when needed?	It is to get stakeholder feedback on this and other issues in relation to the calculation of the IRTC that the AEMC has published the discussion paper, modelling report and this second draft determination.
	It is often the intra-regional transmission capacity of a region that determines its ability to import power from another region.	This would then be reflected in the level of the IRTC from other regions to that region. If it is a result of insufficient transmission capacity then that would be expected to be resolved by a TNSP seeking to augment the network and the application oft he RIT-T.
	The modelling carried out reflects some additional identified issues that need addressing before the results of the modelling are robust enough to be used for developing the basis of	A lack of robustness to the modelling is not a view shared by either the AEMC or its consultant.

Stakeholder	Issue	AEMC Response
	the IRTC.	
	One of the concerns the MEU has with the MLEC and LEC is that the design of pricing used in the Rules and implemented by TPrice, already have a number of shortcomings.	Broader consideration of pricing methodologies is beyond the scope of this rule change. Fundamental changes for a method that is overlaid on the intra-regional charging method would introduce additional cost for an uncertain level of benefit.
	Except for Victoria inter-regional charging would be from one region to another.	The AEMC notes that NSW also has two adjoining regions. In their additional analysis in this section the MEU appears to be confusing the contractual flows with utilisation of the network.