Australian Energy Markets Commission

CONSULTATION PAPER

National Electricity Amendment (Inter-regional transmission charging) Rule 2010

Comments on the Proposed Rule

Submission by

The Major Energy Users Inc

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The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission. The content and conclusions reached in this submission are entirely the work of the MEU and its consultants.

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Executive Summary

The Major Energy Users Inc (MEU) welcomes the opportunity to present its views to the AEMC on the Inter-regional transmission charging rule change proposal.

The MEU considers that the AEMC should reject the proposed rule change.

The Consultation paper provides no quantification on the costs and benefits of the proposal, let alone quantification of the materiality of the issues.

The MEU believes that whilst the proposed rule change conceptually seeks to 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 consumers.

Moreover, the MEU considers that 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 Policies review have not been addressed[1], as the AEMC's Final Report was silent on the issue.

This rule change proposal is similar to the recent SENE rule change proposal. It not only lacks quantification but also undermines key principles underpinning the NEM. Prioritisation of key issues by the MCE/SCO would not go astray.

[1] For example see figure 16 in CRA report "Updating the Comprehensive Reliability Review quantitative analysis to account for CPRS and MRET", December 2008

1. Introduction

1.1 About the MEU

The Major Energy Users Inc (MEU) represents some 20 large energy using companies across the NEM and in Western Australia and the Northern Territory. Member companies are drawn from the following industries:

- Iron and steel
- Cement
- Paper, pulp and cardboard
- Aluminium
- Processed minerals
- Fertilizers and mining explosives
- Tourism accommodation
- Mining

MEU members have a major presence in regional centres throughout Australia, e.g. Western Sydney, Newcastle, Gladstone, Port Kembla, Mount Gambier, Whyalla, Westernport, Geelong, Launceston, Port Pirie, Kwinana and Darwin.

The articles of the MEU require it to focus on the cost, quality, reliability and sustainability of energy supplies essential for the continuing operations of the members who have invested $ billions to establish and maintain their facilities.

1.2 The MEU view on inter-regional connectors

The MEU and its members recognise that inter-regional connections in the NEM provide the basis for considering the NEM as a true 'national' market rather than a series of regions. In fact, the NEM is really a series of interconnected regions where, in the view of MEU members, there is too high a frequency of congestion on interconnectors thereby causing regional price separation. These separations allow regional generators to use their market power to set regional spot prices at opportunistic pricing levels rather than pricing based on strong competition.

It is because of the impact of this opportunistic pricing of the regional market, that the MEU has consistently stated that the regulatory test for interconnectors should recognise the impact of regional price separation.

The MEU has also been a strong supporter of the principle that those that benefit from investment in the NEM should bear the cost of that investment on a cost reflective basis and equitable basis.

This means that, **in principle**, the MEU would support allocating the costs of inter-connectors to the beneficiaries of the interconnectors, but this "in principle" support needs to reflect a number of issues which are developed in more detail in section 2 of this submission.

The MEU was a significant contributor to the 2005 and 2006 debates with the AEMC, which ultimately resulted in the 2006 rule changes creating chapter 6A of the NEM rules. Many features of the chapter 6A transmission rules then flowed into the 2008 revision of the chapter 6 distribution rules. At the time the AEMC made it clear that the chapter 6A rules were designed to further encourage investment in transmission assets as the AEMC saw that such investment was in the long term interests of consumers.

A core feature of chapter 6A was that:

- Optimisation of transmission assets would no longer be applied
- Capex would be approved ex ante and there would be no controls on how this capex could be expended
- The ability of the regulator to assess the reasonableness of the quantum of capex claimed was proscribed
- Actual capex would not be assessed ex post for prudency
- Actual capex would be automatically rolled into the regulatory asset base (RAB)

The outcome of these changes is there has been an explosion in capex claims from network owners, and the powers of the regulator have been so limited that it has been unable to stem the rate at which these large allowances are allowed, causing significant increases in charges for the use of electricity transmission (and distribution) assets. Consumers have been significantly penalised as a result of the unbalanced AEMC rule changes, which have reversed much of the gains from the energy reforms initiated some ten or so years ago.

The chapter 6A rules instituted features which provide an incentive for TNSPs to increase the performance of their networks, especially the service target performance incentive scheme (STPIS) which rewards a TNSP for out-performance of its network against agreed criteria. However, this scheme has no impact at all on the performance of interconnection transfer capability.

Despite the existing Rules being clearly biased to incentivise (excessively so in the view of the MEU) and causing a massive increase in investment in intra-regional transmission networks, this there has been almost no investment in increasing inter-regional electricity flow capability. The MEU considers that the causes of this lack of investment in inter-regional transmission is a much higher order issue for the NEM than this proposed rule change which merely allocates costs between consumers.

A key part of the transmission review was on how pricing could be improved to send better signals to generators and consumers to cause greater efficiency in the use of transmission assets. There were a number of changes made, but even in this process, it was recognised that the outcomes of the review still relied very heavily on averaging of costs which still provided a significant dampening of the signals. Because of this recognition that signals were still relatively weak, the aspect of inter-regional was hardly considered as a major issue at that time. The MEU is still of this view and has addressed its comments on the proposed rule change with this assessment in mind.

1.3 The MEU view of the market as a whole

Consumers are already seeing electricity costs rising very quickly, from a range of causes, such as:

- Generator market power (the AER has identified that Torrens Island Power Station in SA has market power when regional demand exceeds 2500 MW) and a significant contributor to this ability to exercise market power is that inter-regional connection is too weak
- Steeply rising transmission and distribution network prices – on average these will rise in real terms by ~50% over the next five years
- The electricity market exhibits excessive volatility in electricity prices, and as a result retailers are including in retail price offerings, large risk premiums which are causing significant retail price increases
- Implementation of the proposed carbon emission reduction program (CPRS)
- Implementation of the 20% renewable electricity target (eRET)
- The indirect costs caused by the need to augment networks to meet the CPRS and eRET requirements
- Sundry other Federal and State Government renewable energy and climate change programs and ‘initiatives’, such as feed-in tariff schemes, climate change levies, energy efficiency programs, etc

Overall, there is a general expectation that electricity supply costs will rise in real terms by 100% or more over the next few years as a result of these changes, which are also largely driven by myriad government interventions in a supposedly competitive market. This is having a chilling effect on downstream investments and creating an environment where ability to pay is becoming a major issue for all consumers, ranging from large industrials facing international competition to small consumers, especially in the lowest income quintiles..

There are many fundamental flaws in the current transmission revenue and pricing framework and these are likely to be accentuated by the many governmental policy interventions onto a competitive market. The MEU considers that these are clearly higher priority issues for review than the aspect of some cost re-allocation addressed by this proposed rule change. With the proposed rule change lacking any quantification, it is very unclear whether, on a value basis, this proposal should proceed ahead of more pressing issues[2].

1.4 What is the impact of this proposed rule change?

Overall, whist the principle behind the rule change has a degree of acceptability (as it should lead to greater cost reflectivity) the MEU is very concerned that the benefits that might flow from it, will be swamped by the detriments and inconsistencies that it generates.

The MEU develops its views in the following section on a number of the inconsistencies it sees in the development of the rule, that the AEMC must address, before it allows the rule change to be implemented.

In addressing these inconsistencies, the MEU is concerned that the complexity that then arise will make the implementation too complex to deliver a sensible and commercial outcome for consumers.

The rule change proposal posits that consumers 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, as is the same with respect to the SENE rule change proposal, there is no attempt to quantify either the costs or benefits of the proposal, let alone the materiality of the issue.

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[2] For example, in the AEMC review of climate change policies, modelling by CRA ("Updating the Comprehensive Reliability Review quantitative analysis to account for CPRS and MRET", December 2008) indicated the potential for blackouts and brownouts in SA. However, even though the MEU expressed concerns on this issue, the Final AEMC report was silent on this aspect.

2. An overview of the issues behind the proposed rule change

The proposed rule change had its origins from a request of the MCE for the AEMC to assess whether the NEM rules would still be effective with the introduction of the Federal Government decisions to:

- Increase the Mandated Renewable Energy Target from the nominal 5% of the electricity used in the NEM to 20% (eRET), and
- Introduce a cost for carbon emissions via the proposed Carbon Pollution Reduction Scheme (CPRS).

The AEMC undertook a major review process to identify whether there were changes needed to the NEM rules to allow the implementation of these policies. The AEMC came to the view that the NEM rules are robust enough to manage these policy impositions but recommended changes to improve the outcomes of the policies.

It is pertinent to observe that the AEMC advice to the MCE states clearly[3]:

> "The CPRS and expanded RET will result in structural transformation of the Australian energy markets – placing pressure on market participants and consumers to change the way they produce, trade and use electricity and gas.
> Despite these pressures, we have concluded that the existing competitive energy markets, supported by efficient economic regulation of the monopoly network sector, continue to provide the most effective response to major changes in economic and policy circumstances."

That is, the AEMC concludes there is no need to change the **existing energy market structure** as a result of the imposition of these policies. The AEMC then adds[4]:

> "The changes we have recommended to market frameworks seek to improve and strengthen the ability of the energy markets to respond to the policies while continuing to meet the desired market outcomes of efficient and reliable energy services."

Implicitly the AEMC sees that its "improvements" seek to enhance the ability of the energy markets to provide a better response from the imposed policies. Effectively the AEMC sees that its recommendations will assist the implementation of the eRET and CPRS policies, irrespective of the quantum of

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[3] AEMC Questions and Answers on the Final Report Review of Energy Market Frameworks in light of Climate Change Policies 30 September 2009

[4] ibid

costs involved so long as the market outcomes (which will reflect the interventions) are seen to be "efficient" and "reliable".

2.1 The Origins of the Rule change

In its final report to the MCE on the impacts of climate change the AEMC observed that although the current level of inter-regional transfer of power is modest (and therefore the need for inter-regional transfer cost allocation was not a material issue) the advent of CPRS and eRET could change this dynamic and result in significant inter-regional transfers measured annually, making the issue "material".

The AEMC commented (page 42):

> "The recommendation reflects our finding that transmission investment to support flows between and across NEM regions is likely to increase in significance as a result of market responses to the CPRS and the expanded RET. The proposal would, through the improvements to price signals and cost-allocation, therefore better achieve the NEO by promoting the efficiency of this transmission investment."

The AEMC goes on to comment (page 42)

> "The proposal seeks to improve the overall cost-reflectivity of transmission charges, and remove existing implicit cross-subsidies between customers in different regions. These cross-subsidies could represent a potential barrier to the coordinated planning of transmission investment across regions."

In principle, the MEU does not dispute these observations, and supports the principles that the beneficiary should pay for the service it receives, and that cost reflectivity in pricing is a worthy goal.

Against this, up to the present time, the benefits of simplicity in "beneficiary pays" and "cost reflect pricing" have been seen as being attractive principles. Indeed, in many cases this approach still holds sway in many aspects of network pricing.

For example, in the Chapter 6A rules, there is a preference for transmission charges to reflect the usage of the transmission assets at times of peak demand. Clause 6A.23.4(e) states:

> "Prices for recovering the locational component of providing prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated."

Despite this, the AER pricing guidelines allow a TNSP to select whether to develop pricing on the peak usage days or on an annual average basis; as a result most TNSPs use the annual average because this is easier and is what they have always done. The AEMC highlights in its final report that because of this disparity AEMO, as the Victorian TNSP, must be required to change its pricing policy (that uses the 10 peak days in a year to assess usage) to be the same as the other TNSPs that use annual average usage. Accordingly, the AEMC observes (page 47) that:

> "...it would be necessary for AEMO's approved pricing methodology for Victoria to be amended."

This raises the question as to 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 this new requirement established by AEMC in the proposed rule change?

2.2 Reliability of supply is enhanced by strong interconnection

Reliability of supply across the NEM is improved by strong interconnection, and this aspect has been not been fully addressed by the existing rules nor by the (partial) assessments of the Reliability Panel, where reliability of networks and interconnectors has had less focus than increasing the incentives for increasing generation investment.

A concerning aspect of the current proposal to allocate inter-regional costs in an exporting region to power importing regions, is that the benefits of interconnection in terms of reliability has been not seriously considered as an element of the proposal. 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.

This then raises the concern as to why consumers in a normally importing region should pay for transmission assets in a normally exporting region, when the exporting region gains a benefit from the presence and occasional use of the interconnector. If the basis for assessing the load export charge is made on the basis of the relatively small volumes of the power transferred, then the exporting region gains a significant benefit which is paid for by an importing region.

For example, on 28 January 2009, Victoria imported from Tasmania some 56 MWh of power or an average of 2.3 MW for the day[5]. The value of the imported power sold in the Victorian spot market was $4.9m (at an average cost of $1396/MWh), yet the value of the imported power sold in Tasmania was $170k (at an average cost of $49/MWh). On such a day, the mere presence of the Basslink interconnector provided Victorian consumers with a significant commercial benefit as it had a major impact on depressing the spot price for Victorian consumers.

If Victorian had not had access to the power from Tasmania, there is a likelihood Victoria might have suffered a shortage of power causing blackouts, which it did the following day due to failure of Basslink[6], indicating that Victoria is a the beneficiary of reliable supplies of power from Tasmania.

Thus not only did Victoria receive much greater value for the power it imports, but it also receives a significant reliability benefit due to the interconnection with Tasmania. Therefore, it is clear that there is a need to reflect the value of reliability of supplies which might be reflected in average flows, or the length of time power flows.

2.3 Competitive neutrality

The National Electricity Law and the associated rules require that any decision made to change the rules must ensure that competitive neutrality is maintained. Whilst competitive neutrality is usually applied to supply side entities, it also applies to consumers.

Implicitly the proposed rule does not appear to impact on competitive neutrality except that it implies that the cost allocation is likely to be based on the quantum of power transferred over a significant period of time, such as a year. However, the approach does not appear to reflect the importance of any power flows at any given time.

Such small flows could be for overcoming reliability issues or to offset a large spot price change, where the small flows are in one direction for short periods but which have a massive impact on consumers in the importing region to avoid blackouts or large transfers of wealth between consumers and generators in the importing region. Flows in the other direction might be much greater in aggregated volume, but have a minor impact on consumers in the other region.

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[5] To put this amount into context, his needs to be compared to the highest demand for Victoria and Tasmania for the day of 11,228 MW, and a daily average of nearly 9000 MW

[6] When Basslink failed, Tasmania did not have blackouts indicating Tasmania has adequate generation to serve its needs.

For example, it is possible that as a result of the eRET scheme, South Australia might become an exporting region for long periods of time due to large amounts of wind generation being constructed in that recognised windy region. Wind generation is dispatched on a "must run" basis and will bid low prices for its dispatch. This would mean that flow on the Heywood interconnector would generally be into Victoria, and the price for that wind generation would be sold at Victorian prices which are generally low due to high proportion of brown coal power stations that also "must run" for most of the time. On this basis the power flow from SA to Victoria has little impact on the reliability of supply for Victoria or its spot price. However for short periods of time on hot days in SA, there is reduced wind generation and a very high regional demand. This means for those short periods of very high demand, supply from Victoria to SA is critical to maintain reliability and a reasonable spot price.

In basing the load export charge on a volume basis, Victorian consumers would be charged a cost because they received more electricity from SA than was exported to SA, but the value to Victorian consumers in terms of price and reliability is quite modest. But the value to the SA consumers in terms of price and reliability of the smaller amount of power they needed has much greater value to the SA consumers. Yet the allocation process would require Victorian consumers to pay SA consumers despite SA consumers gaining more from the interconnector.

In order to maintain competitive neutrality between consumers there needs to be some recognition of the relative values of the power flows in each direction.

2.4 The cost of power vs the costs of transmission

On page 2 of the AEMC Consultation Paper, the AEMC observes:

> "... the charges for the imported energy may not reflect the long-run marginal cost of serving the loads in the importing region."

Intuitively such an observation cannot be refuted, but it must be addressed if the approach is to result in a cost reflective outcome.

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 process for assessing the delivered costs of power to a demand node reflects significant averaging. Each region is based on a single supply node, and all power is assumed to be provided to and from that point.

Users remote from the regional node pay transmission charges reflective of the distance they are from the node and also pay a premium for the losses assessed in serving the supply from that regional node to the point of usage. Generators are only charged for the transmission from their supply point to their connection with the shared network but do pay a premium for the losses assessed in transporting from their supply point to the regional node.

This approach allows generators significant freedom to locate where they desire as the costs for transmission in the shared network are paid for by consumers. Within a region, generators operate on a notionally competitively neutral basis, and generators outside the region also provide supply into the NEM as a whole on a competitively neutral basis. This means that generators, regardless of the region they are located in, compete on an equitable basis.

Overall, the current Rules clearly allow competitive neutral generation, subject only to congestion in the transmission network.

However, 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 consumers 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?

For example, a generator is dispatched in an adjacent region at $40/MWh. The cost to transport the power to the border of the importing region might be $5/MWh, implying a price for power at the border of $45/MWh. Within the importing region, a generator offers its output at $41/MWh but because its offer is higher than that in the exporting region it is not dispatched, perhaps causing consumers in the importing region to pay a higher price for the power than they otherwise might.

The issue gets more complicated with the relative locations of the regional nodes and the regional boundary.

For example, 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.

This becomes more complex if there are multiple interconnections between the two regions (such as between Queensland and NSW and between Victoria and SA). The load export charges for the different interconnectors will be different yet the amount of power transferred will be a net amount between regions. Further, there are times when there are different directions of flow on the two interconnectors (eg between Murraylink and Heywood).

The proposal does not assess whether consumers will pay more for their delivered power under the proposed change than necessary and whether the proposal might reduce competitive neutrality between generators and regions.

Further, the proposal does not provide any guidance to the regulator or the affected TNSPs as to how these issues are to be addressed.

2.5 Addressing the allocation method

In the Consultation Paper (page 4) the AEMC states:

- "the charge would reflect the flow of electricity from one 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; "

The charge 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.

Using the Victorian/Tasmanian interconnector, Basslink, as an example there was, over the entire year of 2009, an average flow from Victoria to Tasmania of some 181 MW or 1.6 TWh, with Tasmania importing 2.1 TWh valued at $117m (or $55/MWh) and Victoria importing 0.5 TWh valued at $79m (or $150/MWh).

For just over a third of the time in 2009, Victoria imported power and provided power to Tasmania for the remaining time.

To average the flow so that costs of intra-regional transmission could be allocated, there are a number of bases on which the allocation might be based, viz:

- Value of sales giving a cost share of 60:40 (Tas to Vic)
- Period of time giving a cost share of 71:28
- Volume of power giving a cost share of (81:19)
- Reliability benefit giving a cost share of (0:100)

If, as is the case between SA and Victoria where there are two interconnectors, it is a common occurrence that flow on one interconnector is reverse to the flow on the other – in 2009, this occurred to some degree for 40% of the time, and reached a value where flow from Vic to SA on Heywood was 376 MW west and flow from SA to Vic on Murraylink was 134 MW east. Over the entire 2009, the average flow on Heywood was 82 MW west and on Murraylink was 20 MW east.

Therefore 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. For instance, the reason for the counterflows between Heywood and Murraylink reflect the difficulties in transferring power on an intra-regional basis, and the congestion that occurs intra-regionally. The value of the assets transferring power from SA into Mildura over Murraylink is much lower than the value of assets transferring power from the generation in eastern Victoria to Mildura[7]. So there is considerable value to Victorian consumers in utilising SA transmission assets to supply power to Mildura than building their own assets. Yet because the power supply in Victoria is located well to the east, the cost of assets delivering power to Heywood from Victoria will be considerably higher.

If each interconnector is to be assessed separately as appears to be the basis of the proposed rule (see third dot point in consultation paper on page 4), this results in the absurd outcome that (using 2009 data) SA consumers would pay a high load export charge for the 82 MW Victoria delivers to Heywood, but because the SA regional node is closer to the transfer point at Murraylink than the Victorian regional node (and therefore the LEC for SA export via Murraylink is likely to be lower than the import LEC via Heywood) SA consumers would receive a lower load export charge for the 20 MW they send back to Victoria via

[7] This is due to the distance of Mildura in Victoria from the centre of generation in Victoria compared to the distance of Mildura from the centre of generation in SA and the relative weakness of the intra-regional transmission to Mildura

Murraylink than they pay to Victoria for the transfer of this amount of power on Heywood.

The absurdity level becomes higher when it is seen that SA consumers might pay a load export charge based on the net 62 MW they receive from Victoria, but in paying this they provide Victorian consumers with a considerable saving by not having to augment the transmission network intra-regionally to better serve Mildura.

Where is the equity for SA consumers?

2.6 Transfer of the load export charge between regions

The proposed rule states that the load export charge (LEC) will comprise a locational TUoS component, a non-locational TUoS component and a common service component. The costs of the LEC for the importing region will be added to the equivalent elements of the importing region transmission charging elements. Further the SRA residue and proceeds rather than being allocated to the locational element of TUoS as current will be incorporated in the non-locational element of TUoS.

This change means that the locational element of TUoS in the importing region will become distorted by the addition of locational TUoS from the LEC. As locational TUoS is calculated from the regional node, this approach will provide a penalty on consumers located close to the point of importation.

Neither the consultation paper nor the proposed rule provide any reason for making this change, yet it will unnecessarily increase the costs incurred by consumers located close to an importation point.

The MEU considers that such a change requires more explanation and justification.

2.7 Assessment of the transmission costs to develop the load export charge

The MEU 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. On page 4 of the Consultation Paper, the AEMC states:

> " 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; "

In principle, this appears to provide a simple basis on which to develop the load export charge (LEC). However, it requires a number of other features to be recognised (and incorporated) in order to make the charge a cost reflective one.

What appears to be simple in concept becomes much more complex in its implementation.

Firstly, there needs to be a determination as to whether the LEC is an average of the net flows or is to be calculated for both regions, reflecting the reversal of flows that does occur on an interconnector, but does not do so in the case of loads – loads are always a demand point ranging from zero to a larger number. Trying to apply this principle to an interconnector, the notional load will vary between a large positive number and a large negative number. Therefore, is the load netted and calculated for just one direction, or is there to be an LEC calculated in both directions and applied to the flow in each direction, and then the TNSPs net the amount of money that is involved?

The next aspect is that the current rules imply that the costs for transmission allocation should be made on the basis of the maximum demand on the network If the flows are incurred at times of low demand on the intra-regional network, should the cost allocation reflect this? Clause of the rules 6A.23.4(e) states:

> "Prices for recovering the locational component of providing prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated."

The implication is that cost allocation when developing the LEC 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. It might be acceptable for a TNSP to charge its intra-regional customers on the basis of averaging (although the MEU disagrees with this premise), but is it acceptable for them to be allowed to charge customers outside their region on this basis? The MEU considers this is not acceptable.

2.8 Summary

Although the principle which underpins the proposed rule change is prima facie, a simple and supportable one, when the implications are examined in more detail, there is a clear need to identify in the rules, the basis on which such an allocation of the costs must be made, and to eliminate anomalies that it will cause in terms of unintended transfers of benefits and detriments between regions.

As a minimum, the following aspects need to be resolve in such a way that there is no distortion introduced. The rule must clearly identify how the following aspects are to be integrated into the calculation of the LEC:

- Relative benefits to increase the reliability of supply
- Relative value of the power flows to each region
- As the LEC effectively increases the cost to consumers of imported energy, how should this increase be balanced against the cost of regional generation
- On what basis should import flows be weighted against export flows
- Addressing the LEC on imports which are then exported on a different interconnector
- Developing the locational TUoS within a region to include the impact of the locational element of the LEC TUoS
- Accommodating differing approaches to intra-regional cost allocation methods which do comply with the rules

In fact, the MEU sees that 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 MEU considers that the AEMC needs to examine in considerably more detail the consequences of the proposal.

3. Aspects not examined by AEMC

The origin of the proposal is to allocate the cost of transmission assets a power importing region will use in any region. The AEMC points out that such a proposal is cost reflective, and therefore should be implemented. It notes that by using assets in another region, the consumers in the importing region receive a considerable benefit in terms of lower power prices.

It is based on this premise that the AEMC seems to justify its view there is a need to implement this load export charge.

The MEU has long been a supporter of the view that justification of interconnector augmentation should include the benefit consumers get from the greater competition between generators that results from this investment. The MEU view has been 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 is a "transfer of wealth" between generators and consumers. This is inconsistent with the fact that as consumers pay for transmission services, they should not have to share the benefit of the investment with generators.

Appendix 1 provides the requirements to gain approval for investment in the transmission network (regulatory investment test – transmission). Essentially the RIT-T requires a cost benefit analysis to demonstrate that the investment in transmission provides a net benefit. Arising from the RIT-T, there come three basic issues.

1. Firstly, the rule change proposed is predicated on the premise that consumers in an importing region get a benefit from using the assets paid for by consumers in the exporting region. The AEMC observes that consumers in the importing region will benefit from lower prices in the spot market that imports bring and because they do they should pay for the use of the assets that allow this benefit. The MEU does not dispute this, but points out that the decision of the AEMC not to allow the lower spot price that will result from augmenting an interconnector to be considered a benefit, as it is only a "transfer of wealth" (and a transfer of wealth does not provide a net benefit) also results in a lower spot price for consumers in an importing region.

   It seems that the AEMC, in developing this rule change in the final report to the MCE on the impacts of climate change policies, has used an argument to support its case, but one which it has consistently denied should be allowed in the RIT-T for augmenting regional interconnectors. There is a clear inconsistency in the approach of the AEMC.

   The MEU agrees that that a reduction in the spot price in an importing region should be used to quantify a benefit from investment in the transmission network (and on this basis the assumption made by the

AEMC would support the proposed rule change) but, for the sake of consistency, the same assumption should be allowed to apply when assessing the benefit of augmenting a regional interconnector. The MEU considers that the benefit to consumers of augmenting regional interconnectors should include the impact on the spot price movement.

2. Secondly, from the view of a consumer in an importing region, the decision to levy a charge for use of assets in the exporting region, has the same appearance as an investment in the transmission network in the importing region, and the costs will be charged on the consumer by the TNSP in the importing region. The RIT-T requires there be a cost benefit analysis undertaken to assess whether the consumer in the importing region gains from the cost of its "investment of assets in the exporting region" is outweighed by the benefit the consumer gets from the reduced cost of power by importing power rather than generating it locally.

   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.

   Implicit in this axiom is that, if the value of the benefit is less than the cost to be incurred, then the price paid for the service must not exceed the value of the benefit, and a "prudent discount" must apply to the cost of the service estimated by the TNSP in the exporting region.

   The AEMC does not ensure that the rule change should require the assessment of both the cost and the benefit before the AER is required to implement the new structure for charging by a TNSP, and how the AER is to assess the value of the benefit to the consumer in the importing region. As the value of the benefit is directly derived from the reduction in the spot price for power, then this concept must equally apply to benefit consumers gain from reductions in the spot price resulting from other investments.

3. Thirdly, the AEMC has not assessed on what basis any cost allocations must be made. Section 2 above provides a number of aspects that need to be clarified in the rule to allow a proper assessment to be made of what the costs are, how they are to be assessed, and then allocated.

It would appear that the AEMC, in its report to MCE, has identified that there is a conceptual basis for changing the way TNSP costs should be recovered, but it has failed to carry out any deeper analysis of the problems that arise from the attempt to implement the concept.

The MEU considers that much more work is required by the AEMC to ensure:

- There is consistency of approach to this and related issues in the NEM,
- That it examines what might be seen as unintended consequences of the proposed change,
- There is clear and unequivocal direction provided to ensure that the costs and benefits are properly evaluated
- Any need for prudent discounts is permitted.

4. Response to the specific questions raised

4.1 What should be the composition of a load export charge?

1.1 As a charge is proposed to be calculated for an export load in the same way as other loads, how should the export load be defined? That is, should an export load be defined as a notional interconnector that joins two regions or should individual connection points be recognised? How does the definition of the export load impact on the calculation of the load export charge and the redistribution of settlement residue amounts as discussed in the following sections of this paper?

The MEU agrees that the way the export load charge is calculated is extremely vexed. Section 2 provides the MEU views on the issue. The MEU considers, while the concept has merit, the use on an LEC is probably inconsistent to many other aspects of the rules.

If an LEC is to be implemented, then the MEU considers there are a number of key elements that must be used in calculating the LEC:

- A cost benefit analysis must be undertaken to ensure that the benefits exceed the costs to be allocated to an importing region.
- The LEC must not exceed the benefit consumers in the importing region get, even if this means a prudent discount is needed
- The value of the benefit of the transfer to consumers in each region should be used as the basis to assess relativity between import and export flows, not volume
- The value of reliability needs to be included in the benefits
- Where multiple transfer points are present, absurd outcomes (such as described in section 2.5 above) must be avoided.
- LECs should be calculated at peak usage times, not averaged over 12 month's usage.

1.2 Do the existing provisions under the Rules provide for cost-reflective price signals in relation to the use of the transmission network by a region that imports electricity from an adjoining region?

No.

As the proposed rule notes, AEMO as the Victorian TNSP will be required to change its pricing methodology from usage based on the 10 peak usage days to the annual averaging used by other TNSPs, even though AEMO applies the rules more rigorously.

The rule implies that there will be an edict on the pricing approach, regardless of the benefits consumers paying for the LEC will receive. This does not follow the principle implicit in the rules that there is required a cost benefit analysis to be undertaken before new assets can be added to a consumer's transmission costs, and these costs can only be added if there is a net benefit.

The rule assumes that the NEM is a cohesive entity (which it is not) that reflects equity in the transfer of power between regions. In fact the value of the power transferred between regions has different values at different times and when flowing in different directions. Therefore the benefits that are attributed to consumers have different values depending on a range of factors, yet the rule implies that power flows are all equal.

Do customers in an importing region use the exporting TNSP's services in a similar way to customers within the region?

No. See comments in section 2

1.3 What should be the composition of the load export charge that would reflect the use of the transmission network by customers in the importing region? If the charge should include charges for prescribed TUOS services, should both the locational and non-locational component be included?

The propose rule seems to support that the export point on the regional boundary would be treated as a load at that point, which it is. Therefore, as a matter of equity, the LEC should be constructed to reflect the same basis used for all other consumption points that have the same characteristics.

Despite this support of this view in principle, the MEU points out that no other load consumption point will have the same characteristics, and therefore must have a different structure. In particular, the application of a locational TUoS has the potential to result in absurd outcomes as described in section 2.5 above.

4.2 How should a load export charge be calculated?

2.1 Is the proposed load export charge consistent with the current pricing principles under the Rules?

No. See comments in section 2 above.

2.2 What are the differences in the current pricing methodologies adopted by TNSPs and how would any differences need to be addressed? Given that, under the proposed Rule, TNSPs would levy charges on each other, what would be the impact of differences in pricing methodologies of those charges?

Pricing methodologies vary between all TNSPs, with the greatest difference being where Victoria bases its pricing on the 10 highest demand days and the others on annual averaging. The MEU considers that the Victorian approach most closely reflects the current rules (see section 2.7), but the AER has (unwisely) permitted TNSPs to select their own approaches, resulting in the differences

Another difference is the way embedded generation is treated between regions. For the purposes of the LEC calculation, an inter-regional transfer point could be likened to a demand point which has embedded generation associated with it. It has been noted that some TNSPs give better incentives to embedded generation than others, so care is needed to ensure that the "approved" approach reflects the reviews for embedded generation and demand side responsiveness.

To make the LEC even approach some degree of equity, all TNSPs would have to use a standardised approach to pricing methodology and to the implementation of that methodology.

2.3 What level of discretion should be given to TNSPs in calculating charges? Should any specific provisions be made to account for potential differences in pricing methodologies?

As noted in the answer to question 2.2, to maintain equity between consumers, a standardised pricing approach will be needed by all TNSPs.

2.4 How prescriptive should the pricing requirements for a load export charge be? For example, should the Rules specify the types of assets to be included? Should the calculations for the load export charge be based on gross or net interconnector flows?

There is a need for prescription in the calculation of LECs to ensure there is equity across all consumers.

As noted in section 2.5, it would be absurd if the pricing approach used by Victoria when it was exporting to SA via Heywood was different to that used by SA when it exported to Victoria via Murraylink, bear5ing in mind that for much of the time power imported on one interconnector is exported back on another interconnector.

If prescription is applied to calculating LECs, then to provide equity between all consumers in the exporting region and the importing region, all TNSPs would have to use the same methodology and implementation of the methodology

4.3 How should a load export charge be recovered by the importing TNSP?

3.1 On the basis that the load export charge should promote more cost reflective price signals, what should be taken into consideration in determining how the load export charge should be recovered?

The question implies that the principle behind the change is to engender greater cost reflectivity of price signals, a counter question must be, why? Price signals are to deliver an outcome. Generators in a region do not see these price signals so they will not be incentivised to change their decisions and as the whole concept behind the rule change was driven by the impact of climate change policies, the MEU fails to see why the AEMC should see this rule change in light of price signals.

In fact the outcome of this rule change is to engender price equity between consumers. That is, the beneficiaries of using assets in another region should pay for that use, rather than consumers in the exporting region paying to provide a benefit to consumers in another region. When looked at this way, there is no value in attempting to send price signals to generators, and the existing price structure of the importing region TNSP is assumed to send the necessary pricing signals needed for consumers in that region.

Therefore whilst the pricing developed for the LEC in the exporting region needs to provide equity between the exported power and the consumers in the exporting region, there is no such imperative to provide price signals different to those that already exist in the importing region.

The MEU considers that the total cost of the LEC imposed on the importing region should be recovered from consumers in a way that reflects the structure of the price signals already in place in the region.

3.2 How should any auction proceeds be distributed to customers in an importing region?

The MEU notes that the rule proposal allows for the auction proceeds to be included in the non-locational TUoS rather than the current practice of including them in the locational TUoS.

There are reasons for the current practice, yet the AEMC provides no basis for making the change. In the absence of a reason to change, the MEU questions why the change is proposed or needed.

4.4 Would introducing a load export charge impact MNSPs?

4.1 How does the proposed load export charge impact on customers in regions that import electricity from a region interconnected by an unregulated interconnector? What, if any, specific provisions should be considered as a part of this Rule change process?

An MNSP is the beneficiary of the use of the network provided by the regional TNSP and paid for by consumers. The MNSP makes its margin by arbitraging the spot price differential between regions. An MNSP cannot function if there is no network provided at either end of the market interconnector.

An MNSP can be likened to a generator. A generator has its output connected to the shared network as a shallow connection, and makes no contribution to the cost of the shared network. On this basis an MNSP should not pay for the shared network into which it injects power.

However, on the input side of a generator, the generator pays for all of the costs upstream of the output connection point. Continuing the analogy, the MNSP would therefore buy the power from the exporting region and sell it at a higher price to the importing region. To get the power to the input end of the market interconnector, it requires the shared network to transport the power from a generator to the input side of the market interconnector. Just as a generator, pays for the provision of its fuel and the transport of the fuel to the generator, so too should the MNSP pay for the costs to source and deliver the "fuel" to its input point.

The MEU considers that an MNSP should pay for the LEC 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 provision of assets needed to deliver the service to it, and reflects equity between consumers 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.

4.5 What factors would need to be considered to provide for administrative efficiency?

5.1 What are the administrative impacts on CNSPs by introducing new type of payments between CNSPs? For example, how often should payments be made? Should the payments be made on a gross or net basis? Would TNSPs be exposed to a new credit risk and, if so, how should the risk be managed?

The MEU has not a view on the specifics of these questions, but raises the point that the costs of implementation of the rule change will be significant. It is also not sure that the amount of cost transfer will be material in comparison to the costs of implementation.

If these implementation costs exceed the benefit that accrues from the proposed rule, then the rule should not be implemented.

As to the frequency of making such transfer of costs, the MEU points out that consumers do need some stability in the charges they see, and TNSP charges should not be set more frequently than annually.

4.6 What would be the appropriate level of prescription and transparency for any new pricing provisions?

6.1 Are there other factors relating to the level of prescription and transparency that have not already been considered under the other questions raised? For example, should payment terms and the billing period be specified for payments between CNSPs?

Due to the various bases the LEC could be developed (for example see section 2.5 above), there is a need for a high degree of prescription needed so that all consumers 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 or generated the absurdities depicted in section 2.5

6.2 In regions where there are multiple TNSPs, does the way in which a CNSP bill and receive payments from TNSPs within that region need clarification and/or prescription?

Yes. There is a need to have competitive neutrality in the NEM, and this particularly applies to consumers and to MNSPs. To ensure competitive neutrality applies between regions, prescription is essential.

6.3 Should a load export charge be able to be implemented without the requirement for the AER to produce new pricing methodology guidelines? If so, would any clarifications need to be included in the new Rules?

No. There must be commonality of approach and this can only be ensured with AER approval of pricing approaches.

4.7 What transitional provisions should be considered to ensure stability and regulatory certainty?

7.1 Implementing a load export charge would likely result in the one-off redistribution of transmission service charges. This redistribution may impact some customers more than others. Should any specific provisions be put in place to manage the potential change in charges?

As the recent large increases in network charges experienced in NSW attests, price shocks for consumers should be avoided. This means that there should be a transition to higher charges wherever possible.

7.2 Would it be feasible to implement the proposed load export charge by 1 July 2011? What factors should be taken into consideration to determine the implementation date? What transitional provisions would need to be in place to allow any new provisions to be implemented as soon as practicable while ensuring that regulatory certainty is maintained?

No. The MEU considers there too many aspect of the proposed rule that must be worked through to ensure that the resulting outcome reflects equity, a workable approach and clarification of the anomalies that are so very apparent in the current proposed rule.

Just as importantly the AEMC needs to demonstrate that the issue is material compared to the costs to implement and that there is demonstrable equity in the rule as finally implemented.

5. MEU Views and conclusions

The eRET scheme is a policy decision of government and is the cause of the increase in renewable generation and CPRS is also a government policy decision with the aim of reducing carbon emissions into the atmosphere. Both have an impact on the energy markets, but more so on the electricity market. The AEMC concluded that both policies could be accommodated within the current market structures but some “tweaking” should be made to give better effect to the policies.

The MEU notes this but makes very clear the distinction that it is not the markets that require adjustment to accommodate the policies but that the market structures could be modified to improve the outcomes of the policies.

With this distinction in mind, the MEU has drawn the conclusion that whilst the proposed rule conceptually imposes a higher degree of cost reflectivity, it has the potential to create more problems than it solves. There is a real risk that imposing the proposed rule could result in a move away from equity, where some beneficiaries receive a greater benefit at the expense of other consumers.

Further, the MEU points out that to achieve an equitable outcome, there will need to be a greater uniformity of approach and prescription imposed on TNSPs than currently exists, and that such prescription will have to be imposed on more elements than needed expressly for this rule.

Whilst the proposed rule has a conceptual basis that meets the principles behind the NEM, there has been no attempt to demonstrate that there is a benefit that will accrue to consumers, or that any benefit that does accrue will exceed the costs that some consumers will have to pay.

Ultimately, any change in the rules should achieve an outcome that is material in comparison to the costs that it will impose on the market as a whole. The proposed rule makes no attempt to assess whether the benefits will be material or what the costs of its imposition will be. In the final analysis it could be that the transfer of costs amongst consumers in different regions will entail more effort than what the outcomes are worth.

In the absence of any quantification of the amounts being considered for the LECs and the costs to implement the change, the MEU cannot comment, but is concerned that the effort will not be worth the outcome.

Even though the current structure provides a degree of averaging of cost allocation between consumers, the current cost allocation approach is typical of trying to reduce a complex issue down to a workable solution. There are many other aspects of the NEM rules which reduce complexity to simplicity through averaging – converting the allowed revenue for an NSP into tariffs is one such approach to reduce complexity into a workable outcome. This rule change addresses a very small part of the overall cost of providing transmission services under the guise if seeking cost reflectivity. The search for cost reflectivity is a laudable goal, but when it is realised that the cost allocation for the bulk of the transmission costs is based on a high level of averaging, it seems inappropriate there should be so much complexity introduced into such a small element of the cost.

The current structure works, and in attempting to refine cost reflectivity in relation to inter-regional transfers, there might be an outcome that improves cost reflectivity in one area that is not in keeping with cost reflectivity in other areas. To put this more bluntly, are we attempting to refine one small element of cost where the greater part of the costs is not and cannot be refined to the same extent?

On a qualitative basis the proposed rule appears to have more detriments and difficulties in implementing the change (none of which have been quantified) than there are benefits for consumers (which have also not been quantified), the MEU considers the AEMC should reject the proposed rule change.

APPENDIX 1

5.6.5B Regulatory investment test for transmission

Principles

(a) The *AER* must develop and *publish* the *regulatory investment test for transmission* in accordance with the *transmission consultation procedure* and this clause 5.6.5B.

(b) The purpose of the *regulatory investment test for transmission* is to identify the *credible option* that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the *market* (the *preferred option*). For the avoidance of doubt, a *preferred option* may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the *identified need* is for *reliability corrective action*.

(c) The *regulatory investment test for transmission* must:

(1) be based on a cost-benefit analysis that is to include an assessment of reasonable scenarios of future supply and demand if each *credible option* were implemented compared to the situation where no option is implemented;

(2) not require a level of analysis that is disproportionate to the scale and likely impact of each of the *credible options* being considered;

(3) be capable of being applied in a predictable, transparent and consistent manner;

(4) require the *Transmission Network Service Provider* to consider the following classes of market benefits that could be delivered by the *credible option*:

(i) changes in fuel consumption arising through different patterns of *generation dispatch*;

(ii) changes in voluntary *load* curtailment;

(iii) changes in involuntary *load shedding*, with the market benefit to be considered using a reasonable forecast of the value of electricity to consumers;

(iv) changes in costs for parties, other than the *Transmission Network Service Provider,* due to:

(A) differences in the timing of new *plant*;

(B) differences in capital costs; and

(C) differences in the operating and maintenance costs;

(v) differences in the timing of *transmission investment*;

(vi) changes in *network* losses;

(vii) changes in *ancillary services* costs;

(viii) competition benefits;

(ix) any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing that *credible option* with respect to the likely future investment needs of the *market*; and

(x) other classes of market benefits that are:

(A) determined to be relevant by the *Transmission Network Service Provider* and agreed to by the *AER* in writing before the date the relevant *project specification consultation report* is made available to other parties under clause 5.6.6; or

(B) specified as a class of market benefit in the *regulatory investment test for transmission*;

(5) require a *Transmission Network Service Provider* to include a quantification of all classes of market benefits which are determined to be material in the *Transmission Network Service Provider's* reasonable opinion;

(6) require a *Transmission Network Service Provider* to consider all classes of market benefits as material unless it can, in the *project assessment draft report* or in respect of a proposed *preferred option* which is subject to the exemption contained in clause 5.6.6(y), in the *project specification consultation report*, provide reasons why:

(i) a particular class of market benefit is likely not to affect materially the outcome of the assessment of the *credible options* under the *regulatory investment test for transmission*; or

(ii) the estimated cost of undertaking the analysis to quantify the market benefit is likely to be disproportionate to the scale, size and potential benefits of each *credible option* being considered in the report;

(7) with respect to the classes of market benefits set out in subparagraphs (4)(ii) and (iii), ensure that, if the *credible option* is for *reliability corrective action*, the quantification assessment required by paragraph (5) will only apply insofar as the market benefit delivered by the *credible option* exceeds the minimum standard required *for reliability corrective action*;

(8) require the *Transmission Network Service Provider* to quantify the following classes of costs:

(i) costs incurred in constructing or providing the *credible option*;

(ii) operating and maintenance costs in respect of the *credible option*;

(iii) the cost of complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of the *credible option*; and

(iv) any other class of costs that are:

(A) determined to be relevant by the *Transmission Network Service Provider* and agreed to by the *AER* in writing before the date the relevant *project specification consultation report* is made available to other parties under clause 5.6.6; or

(B) specified as a class of cost in the *regulatory investment test for transmission*;

(9) provide that any cost or market benefit which cannot be measured as a cost or market benefit to *Generators*, *Distribution Network Service Providers, Transmission Network Service Providers* or consumers of

electricity may not be included in any analysis under the *regulatory investment test for transmission*;

(10) specify:

(i) the method or methods permitted for estimating the magnitude of the different classes of market benefits;

(ii) the method or methods permitted for estimating the magnitude of the different classes of costs;

(iii) the method or methods permitted for estimating market benefits which may occur outside the *region* in which the *Transmission Network Service Provider's network* is located; and

(iv) the appropriate method and value for specific inputs, where relevant, for determining the discount rate or rates to be applied;

(11) specify that a sensitivity analysis is required of any modelling relating to the cost-benefit analysis; and

(12) reflect that the *credible option* that maximises the present value of net economic benefit to all those who produce, consume or transport electricity in the *market* may, in some circumstances, have a negative net economic benefit (that is, a net economic cost) where the *identified need* is for *reliability corrective action*