Australian Energy Markets Commission

Review of the Electricity Transmission

Revenue and Pricing Rules

Comments on the Pricing Requirements

Issues Paper

by

The Major Energy Users Inc

And

Major Employers Group Tasmania

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Executive Summary

This submission is presented by consumers who by and large, pay for the network services in the NEM. Consumers consider that a number of significant changes need to be made to the way the costs for transmission services are allocated in order to achieve greater economic efficiency. Consumers believe that there are a number of fundamental points which the AEMC should consider as part of this review.

1. Resulting form the recent decisions of regulators, network charges now represent a growing proportion of the total costs of energy delivered to consumers. For example in Tasmania by late this decade, transmission costs to consumers will have doubled. This then raises some very pertinent questions:-

    a) Have regulators been too generous or have they been successfully gamed?
    b) Is the current approach to regulation in the Rules and as interpreted by regulators encouraging too much network capex and preventing other forms of relieving network constraints?
    c) Will the several billions of dollars in network capex awarded in the last round of regulatory reviews likely to be efficient given that the unit network costs of delivered electricity have increased substantially?
    d) There is a national drive to increase investment in the networks of the NEM which has been accepted by many as essential. The TNSPs themselves are mooting the need for several billions of dollars more in network augmentation. Has the economic efficiency of these thrusts for greater investment been tested or is it the result of an hysterical fear that the “lights will go out”?
    e) The Rules actively discriminate against demand side responsiveness and embedded generation. The Rules need to be changed to achieve these outcomes, but how should the Rules be written to incentivise demand management and less network augmentation?
    f) Augmentation of the networks is a consumer funded method for increasing competition amongst generation, yet the Rules and the regulators assume that augmentation will result only in a “transfer of wealth” between consumers and generators and therefore such a benefit from augmentation is excluded from the Regulatory Test. How is this possible?

    g) Network charges (and energy costs) have increased due to transmission constraints and increased exposure to summer peaks.

h) The average system annual load duration curve has deteriorated across the NEM (by around 4% over the past 6 years) providing a price driver for transmission and distribution use of system charges (and energy prices).

2. In order to ensure there is economic efficiency in cost allocation, there is a need to prioritise those aspects which deliver the greatest benefit. Such issues including demand side responses and embedded generation against network augmentation, and allocating network costs to generators rather than all to consumers.

3. Transmission charges are currently a small (but rapidly growing) element of the total cost of delivered energy, particularly when compared to the cost of the distribution networks to consumers. Therefore, there may be a concern that too much effort is going into an aspect which will deliver too low a reward when compared to other aspects which may have a greater impact on consumers.

   Having stated that, there are anomalies within the transmission aspects of the Rules which do lead to blatant economic inefficiencies. Thus, the aim of this review should be to keep Rules relating to transmission relatively simple and not devote too much effort into making the transmission element complex (but accurate) when there are so many other inefficiencies in the NEM which tend to flood the more minor (in cost terms) inefficiencies in transmission pricing.

   Expending too much effort for minor rewards detracts from identifying the more pressing perverse outcomes extant in an energy only market.

After consideration of the issues the efficient outcomes proposed in this submission are encapsulated as follows:-

- The cost of network services should be allocated in relation to demand and not by consumption

- Generators connected to the transmission network should pay for connection costs, and for the costs of the transmission network to the regional node and consumers should pay for the assets used to deliver power to the exit points

- The cost allocations for both generators and consumers should be assessed on the days of peak usage of the network, and not averaged over every half hour. The current Rules state a minimum of the 10 peak days. Half hourly averaging is not reflective of actual usage and efficiency points to the 10 days being the maximum over which the allocations should be made.

- The Rules discriminate against demand side responses and embedded generation, and this discrimination needs to be urgently addressed.

- To assume that parties who are not affected by the outcome will negotiate or follow broad principles is not efficient. This leads to the need for greater prescription in the Rules and arbitration by independent parties (such as regulators) between the parties required to negotiate.

- The Regulatory Test should be modified so that the party paying most for the transmission assets should be permitted the energy pricing outcomes of augmentation made to the network.

- Consumers should have access to the mediation/arbitration facility of the Rules to assist them in their dealings directly with TNSPs

- There are anomalies in allocating the benefits of exporting power to other regions which fall on the consumers of the exporting region. As a minimum the auction proceeds should go to the exporting region and not the importing region, and there is benefit of the costs of the NEM transmission backbone being separately costed and the costs allocated to all users (generators and consumers) in the NEM in proportion to the annual usage in of each region.

1. Introduction

The MEU and MEG

The Major Energy Users (MEU) and the Major Employers Group Tasmania (MEG) comprising some 30 major energy using companies in NSW, Victoria, SA, Tasmania and Queensland welcome the opportunity to provide comments on the Review of the Electricity Transmission Revenue. In particular, the submission represents the views of the Energy Markets Reform Forum (NSW), Energy Consumers Coalition of South Australia, Energy Users Coalition of Victoria and Major Employers Group Tasmania.

The companies represented by the MEU and MEG (and their suppliers) have identified that they have an interest in the **cost** of the energy networks services as this comprise a large cost element in their electricity and gas bills.

Although electricity is an essential source of energy required by each member company in order to maintain operations, a failure in the supply of electricity or gas effectively will cause every business affected to cease production, and members' experiences are no different. Thus the **reliable supply** of electricity and gas is an essential element of each member's business operations.

With the introduction of highly sensitive equipment required to maintain operations at the highest level of productivity, the **quality** of energy supplies has become increasingly important with the focus on the performance of the distribution businesses because they control the quality of electricity and gas delivered. Variation of electricity voltage (especially voltage sags, momentary interruptions, and transients) and gas pressure by even small amounts now has the ability to shut down critical elements of many production processes. Thus member companies have become increasingly more dependent on the quality of electricity and gas services supplied.

Each of the businesses represented here has invested considerable capital in establishing their operations and in order that they can recover the capital costs invested, long-term **sustainability** of energy supplies is required. If sustainable supplies of energy are not available into the future these investments will have little value.

Accordingly, MEU and MEG are keen to address the issues that impact on the **cost, reliability, quality** and the long term **sustainability** of their gas and electricity supplies.

The members of MEU have been involved in nearly every economic regulatory review (both gas and electricity) since deregulation of the energy markets commenced in 1996, as well as participating in the drafting of the electricity and the gas access regulatory regimes As a result, they have accumulated a wealth of knowledge of the relevant regulatory and legislative processes, and in particular observed and experienced a number of perverse outcomes resulting from the application of the rules and regulations over the past decade.

A Brief Statement of the Current National Electricity Market and Consumers' Perspectives

It is apt to recall that the current regulatory processes have arisen from the Hilmer review, which pointed to the release of significant potential benefits to Australian national competitiveness by deregulating the energy supply sectors (gas and electricity) which were either held directly by State governments or were under their direct control, or in the case of gas, largely controlled by a few firms.

However, whilst the reform blueprint was sound (e.g. separation of the generation sector from the transmission and distribution sectors and competition in sectors that are contestable) the drafting of the legislative and regulatory rules was heavily influenced by some governments who were electricity and gas pipeline asset owners embarked on programmes of privatisation and corporatisation. One result was that a number of key elements of the National Electricity Code were skewed to reflect particular interests. For example, in the requirement for a regulator to use a specified asset valuation methodology; the use of derogations which constrained regulators from making independent assessments in some key areas; and in the allocation of costs for the use of the transmission networks. Similarly the requirement for generation (new and existing) to pay only entry costs and shallow connection costs, has enabled the more advantageous sale of generation assets, yet this has created distortions in the NEM ever since.

Nevertheless, the deregulation process made great strides in the nineties, with major improvements in generation availability, reduced costs and new investments in electricity networks. However, the benefits initially seen as likely to flow from reforms have since been dispersed in a variety of ways (such as unrealistically high dividends to state government owners; introduction of government levies on electricity network services; increased litigation and appeals against regulatory determinations).

The following box contains MEU's highly summarised view of major aspects of the current National Electricity Market.

- Electricity users have now seen electricity prices return to levels prevailing prior to the commencement of energy reforms initiated by governments.
- The National Electricity Market is still a series of regional markets with weak inter-connections. Regional price differentials can be very wide.
- The electricity supply industry is now more concentrated. More and more energy suppliers are re-aggregating – both vertically and horizontally – and the potential for the exercise of market power is now greater than ever before.
- There is little depth in the wholesale electricity market, the use of financial instruments is limited and virtually no independent secondary market in such contracts exists. Forward wholesale electricity contracts are only for three years' duration and liquidity in the market is limited.
- Transmission companies essentially continue to operate as network providers on a point to point basis, and are yet to develop new services, such as risk management instruments.
- There has also been regulatory failure, which has stymied construction of inter-State interconnections.
- Economic regulation of transmission networks continues to be effectively based on the building block approach. Incentive-based

The AEMC review of the regulation of transmission revenue is, therefore, very timely and has the potential to address and influence a wide range of issues, including the ones highlighted above. From the standpoint of MEU and MEG, this review's objective should be to deliver changes to the rules that will assist in achieving a **sustainable** and **competitive national electricity market.**

A paramount objective of the review is to meet the objects clause contained in the NEL, viz.

> "The national electricity market objective is to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security

> of supply of electricity and the reliability, safety and security of the national electricity system."

In undertaking its task, the review should also seek to streamline and improve the quality of economic regulation, to lower the cost and complexity of regulation, enhance regulatory certainty, and lower the barriers to competition, in order to deliver greater benefits to consumers.

As pointed out above, industrial consumers have a "four points" approach to electricity supplies. They are:-

1. low cost in order to maintain the viability of the enterprise
2. high quality to avoid outages caused by voltage spikes and dips
3. highly reliable in order to maintain continuity of the operation of the enterprise
4. sustainability of supply in order that the investments made by the enterprise can be recovered.

Consumers therefore require all four of these criteria to be achieved in order for the NEL requirement of "…the long term interests of consumers…" to be met. However, we note the view put by the AEMC that:-

> "where there is a potential trade-off between the long term benefits to consumers, say arising from investment and innovation in network, metering or generation technologies, and the short term benefit of setting prices below their long run economic cost, the benefits of the longer term outcomes should receive due weight."[1]

There is no simple trade-off and this assumption must be considered very carefully. After all it would be a pointless exercise if industrial consumers either went out of business or never invested due to the high costs of electricity transport. We stress, however, that price is not the only variable of concern to consumers. Non-price factors, such as reliability, security of supply etc. are just as important.

Consideration of the issues at hand from a consumer perspective is important as much of the current debate has centred on how the regulatory approach impacts on Market Participants, as they are (at first glance anyway) responsible for paying for the use of the transmission system. This approach seems to ignore the obvious point that it is ultimately consumers who pay for the provision of the network services, regardless as to whether this might be incurred through generator costs, retailer costs, and distribution costs or through lost factors. Economic regulation also involves costs and ultimately all such costs are picked up by consumers.

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[1] AEMC issues paper page 14

The AEMC's review must therefore have sufficient regard to the impact of its rule changes based on a clear appreciation of consumers' perspectives.

The importance of this can be illustrated by reference to the ACCC approach to the regulatory test for new investment, particularly for interconnectors. The ACCC's view is that as generators and retailers pay for transmission costs, then "the transfer of wealth from generator to retailer or vice versa" should not be a consideration as to the feasibility of a new interconnector. However, when this issue is addressed from the standpoint of the consumer, the consumer sees that an interconnector has the potential to give it access to lower cost generation even accepting that there is a premium for the transport. The consumer could also view the resultant reduction in price volatility in its regional market, arising from the interconnector, as valuable. Thus, from a consumer viewpoint, the feasibility of a new interconnector is the difference between what it pays to a local generator compared to what it would pay to a remote generator plus the additional cost of transport net the externalities (such as reducing the market power of local generators and reducing price volatility). In other words, the regulatory test should contain wider criteria by reference to the perspectives of consumers.

The Pricing approach of TNSPs

Transmission networks (and indeed distribution networks as well) have a powerful role to play in contributing to the efficient operation of the NEM and in facilitating competition between generators and regions.

The cost of electricity transport (transmission and distribution) can now comprise over 50% of the delivered cost of electricity, and some of the existing rules relating to the recovery of transmission use of system changes are quite perverse and can discriminate against consumers' interests.

In particular the pricing approach by the NSPs has the potential to provide some quite perverse outcomes, particularly bearing in mind that while the regulators set the allowed revenue, it is the NSPs which set their own prices and this is accepted by the regulators providing that the prices lie within the bounds of the avoided cost and the stand alone cost.

This approach has a benefit to the NSP regardless as to whether the regulator sets a price cap or a revenue cap as even with a price cap the limitation on the NSP is still controlled by reference to a basket of tariffs rather than the examination of each and every tariff and price set by the NSP. By allowing the NSP to set its own prices for individual service, it empowers the NSP and places the NSP in a position of exercising market power with minimal control. Thus the NSP has the ability to exercise this market power in a direction which can benefit the NSP, provide a detriment to new entrant generators and impact where and what consumers must do to minimize there electricity transport costs. What should be seen is that the NSP should not be able to impose this degree of market power and that its prices must reflect the most efficient way to transport electricity between providers and consumers.

Implicit within the current Rules there are a number of cost allocations which impact directly on consumers and create perverse and distortionary outcomes.

Perverse outcome: ancillary service costs

Ancillary services are levied in proportion to the amount of energy delivered, regardless of the actuality of the services provided and the physical relationship between generator and consumer, and the variability of the consumer demand.

A consumer with a flat load profile imposes much less demand on the system for ancillary services than a consumer with a excessively variable demand, yet the larger consumer is levied with a higher proportion of the costs of providing ancillary services than the more demanding yet lesser demand consumer.

Perverse outcome: regional nodes

The assumption that all power goes to a regional node (with losses paid for by the generator) and is delivered from the regional node (with losses paid for by the consumer) creates a distortion which particularly impacts regional consumers. Whilst the logic assumes a radial design of the electricity transmission network, it contains a basic fallacy and cost distortion if the remote generator and the regional consumer are physically located adjacent to each other, or if there is a direct or indirect transmission connection between the two.

For the generator to incur costs to deliver the power to the regional node and for the consumer to pay for the losses for delivery from the regional node and for the costs of transport from the regional node provides a significant distortion and cost penalty which is not reflected in the actuality of the network design

Perverse outcome: locational impacts between generator and consumer

Whilst new generation connected to the transmission network only pays shallow connection costs and losses to the regional node, it is not otherwise exposed to the impact of its location.

This is not the case for a new consumer which is exposed to the losses relating to the regional node and also pays for use of the network as if all power was delivered from the node, thus suffering the impact of its location.

Perverse outcome: Embedded generators

An embedded generator (in the distribution network) is free from the transmission losses to the regional node and gets a relatively modest proportion of the value attributed to its location in relation to transmission load reduction but not for any distribution locational benefit. The embedded generator is required to pay full value for the augmentation of the distribution network to the nearest transmission substation and any augmentation required at the transmission substation and the transmission network.

A generator located adjacent to the embedded generator but directly connected to the transmission network gets no benefit of its location in transmission support and pays for losses to the regional node.

This shows that there is clear discrimination between connecting to the transmission and distribution networks. As noted above there is no benefit to a generator locating adjacent to a large load.

Perverse outcomes: Self generation

A generator located within the confines of a large load (ie downstream of the connection point with the network) receives little benefit as the cost allocation of network charges, being based on the annual peak demand, reflects the occasional use the load has when its generator is off line.

This perversity actively discriminates against self generation and even against demand side responsiveness by the consumer. Direct experience of consumers attempting to provide a demand side response in addition to reducing their costs of power have consistently been marginalised by the processes used by TNSPs and DNSPs to grant a consumer the full benefit of self generation, by reducing the costs of transport.

Perverse outcomes: locational signals

Cost allocations are not cost reflective as 50% of the revenue is “postage stamped” and are different between different NSPs (eg whilst all use the “T-Price” cost allocation model, some use it to allocate for all periods of usage whereas another uses it only for a limited number of “peak demand” days as a better approximation of real usage of the network). These different approaches create distortions and discrimination.

The current allocation of costs for transport services works to the advantage of generators but does not reduce the burden carried by consumers. Currently 50% of transport charges are allocated on a postage stamp basis with the balance being allocated on an asset cost allocation. As generators pay little for use of the assets, locational benefits from the optimum siting of generators and consumers are lost.

<u>Perverse Outcomes: Interconnectors and the Regulatory Test</u>

Inter-regional network augmentations are being constrained by the extent of "postage stamp" prices used by regulators and TNSPs in developing the transmission prices causing a reduction of the full locational signals which would assist in supporting augmentation and inter-regional connections.

The above are only examples of some of the perverse outcomes in the NEM that have arisen from the current pricing approaches applying on and used by TNSPs. They illustrate the key priority issues that MEU and MEG consider should be addressed by the AEMC in this review.

Whilst such approaches can be justified at an economic level the perversities deter sensible decision making by consumers and deter the development of demand side responsiveness in the NEM, and attempts to reduce the loads placed on the generation and networks by reducing demand at critical times. MEU would welcome the opportunity to share the actual experiences of consumers in this aspect of attempting to support the processes envisaged by the NEM architects, but which are being prevented by the pricing approaches used by the NSPs.

The approach by MEU and MEG to this issues paper

The introduction to this submission is identical to that provided as the introduction to the MEU and MEG response to the AEMC transmission revenue issues paper. This is because the following comments in relation to transmission pricing issues paper must be seen in the same context as for the earlier response.

The AEMC has raised a series of questions under a number of headings – requirement for **regulation, context and objectives for the review, current transmission pricing regime, efficiency and transmission pricing – key concepts, relevant NEM context, allocation of regulated revenue across transmission users, structure of prices, pricing of non-prescribed services and inter-regional issues.**

The following sections provide our response based on each of the main headings used by the AEMC to maintain consistency with the Issues paper

Throughout this submission, there are a number of references made to examples. It should be noted that these example are based on actual circumstances and the MEU is prepared to discuss the actuality of these examples and the outcomes with the AEMC.

2. Form of Regulation

There are many activities in the NEM which clearly benefit from true locational signals. A number of these are referred to in the preceding section as the current design of the NEM and the approaches used by the regulators and NSPs lead to many perverse outcomes. Probably of all of the perversities the most consumer related issues are those of getting full value for a demand side response to the signals in the NEM and to allocate costs to truly reflect the extent of assets actually used.

An example of the first is that even though a consumer may only need to use an asset once a year, and then at times of low system demand, it is still required to pay full value for the assets used at that time. The result of this pricing is that a demand side response is allocated much less value by the transmission system, causing a reduction in demand side responsiveness.

An example of the second is that absurd outcomes arise. There are examples of a consumer on one side of a state incurring a share of the costs of transmission assets from the other side of the same state, despite there being large generation assets between the two extremes.

However as pricing signals are the tools on which economic drivers are based, the more these signals are muted or distorted the less value they have in achieving the economic outcomes sought. Further to leave the development of these signals largely in the purview of a regulated entity allows the entity to use the freedoms allowed by minimal oversight to enhance the profitability of the entity at the expense of gaining the NEM outcomes desired.

Such approaches which can be used by regulated entities include:

- Internal price adjustments to prevent economically sensible bypass.
- Pricing to prevent alternative mechanisms to network augmentation
- Pricing to prevent inter-regional connections
- Pricing to prevent demand side responses
- Pricing adjustments in a “basket of tariffs” in a price cap arrangement to improve profitability

Regulators seldom, if ever, examine in detail the tariffs developed by the NSP to ensure that the tariffs are truly cost reflective, relying on the requirement that the tariffs lie between two extremes of avoided cost and stand alone cost. Even where the outcomes show that there is a distortion in the tariffs (by returning higher than expected revenue) the regulators still do not take action.

Thus the allocation of costs is essentially left to the business to carry out without recognizing that the business has other objectives which could well preclude it from developing truly cost reflective tariffs from the approved revenue – the Rules give the task to a party which has a different set of drivers from those needed to develop maximum cost reflectivity in cost allocations.

By allowing the business to set its approach to cost allocation effectively allows the business to establish the allocation to best suit its aspirations which do not necessarily coincide with the aspirations of the NEM which is to provide clear and sensible signals to develop the most economic responses.

Currently regulators only assess the proposed cost allocations in the broadest terms, and then by assessing the ‘over’ or ‘under’ recovery of revenue. This is effectively price monitoring. What does not occur, is the in-depth analysis required to ensure that costs allocations are truly cost reflective, or whether the cost allocations provide a strong enough commercial signal to initiate the most appropriate response to an issue.

Most TNSPs use the commercial cost allocation program “T-Price” yet most TNSPs apply different base criteria (some use each half hour of the year, others only apply the program to maximum peak days). This difference creates a significant difference in cost allocations.

Applying the half hourly allocation results in allocation of costs based on low usage rates of the assets, whereas using the program for a few high demand days results in an allocation which reflects the share of the assets used when operating near their peak capacity. The former approach allocates more cost to continuous users of the system (the flat load demands), and the latter allocates more costs to occasional users of the system (the ones which drive the network to be underutilized for much of the time). Thus major end users are entirely dependent upon, or exposed to, the methodology that best suits the network service provider.

Because TNSPs commonly operate under a revenue cap, they are driven to expand their networks in order to increase the return for their shareholders. This incentivises them to oppose non-network solutions to constraints and to attempt to minimize embedded and self generation. By structuring their tariffs in particular ways, the TNSPs can ensure that these demand side responses and alternatives to non-network solutions are effectively marginalized.

Because of the power of cost allocation in providing signals, this matter is far too important to be left to the TNSPs discretion without the establishment to sound principles, close supervision, and verification of the outcomes.

1. Should transmission prices be regulated and why?

Transmission prices are so closely interlinked with ensuring the most economical outcome is achieved, that to leave this element to the TNSP which has goals which are not necessarily in accord with the aspirations of the NEM, will not result in the desired outcomes. Customers can be disadvantaged by this discretion.

2. If regulation is required what form should this take? For example, should it be less prescriptive and involve greater transparency or be more prescriptive?

The way cost allocation and pricing is developed and as the resulting outcomes have such an important impact on the way the NEM operates, it is essential that the method used and the approach to pricing must be consistent across the NEM and to be as close to cost reflectivity as can be made. Thus there must be prescription in the methodology (for consistency) and the approach (for cost reflectivity) to ensure the best outcome is achieved. The regulator must not only assess the methodology and the approach and the principles, but also verify that the outcomes are achieved. The key here is "outcomes that are efficient", and not a tradeoff between "prescription" and "transparency".

3. What role, if any, should the AER have in determining the nature and form of price regulation?

The Rules should provide the methodology and the principles approach, and the AER should verify the outcomes are consistent with the 'objectives'.

3. Context and Objectives of the Review

Consumers require an electricity supply system which is low cost, reliable, high quality and sustainable in the long term. As mentioned in the introduction consumers have made their own investments which are predicated on the long term sustainability of electricity supply. Thus consumers have no quibble with the Issues Paper when it states:-

> *"The national electricity market objective is to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system."*[2]

It goes on to state that:-

> "… the Review will need to consider whether the means by which the Rule change proposals seek to achieve the desired outcomes or processes result in regulatory arrangements that are clear, transparent, and predictable. These attributes of good regulation are required to ensure that markets and market participants are well informed, thereby enhancing:
>
> • the efficiency of market related decision making by investors and consumers, whether in relation to transmission directly, to generation or retailing services that depend on transmission, or in relation to transmission alternatives;
>
> • the willingness of investors to commit capital to the NEM, thereby reducing its long term cost; and
>
> • the role of transmission pricing outcomes in signalling investment opportunities to potential investors and signalling to consumers the cost of their energy usage choices."[3]

With regard to the first point, it is transmission pricing that drives this outcome. If transmission pricing is based on incorrect or inefficient cost levels and cost allocations, then this outcome will not occur.

The second point is associated with the profitability of owning the network. If the owners were to receive a greater return for the same risk by investing in another type of investment, then there will be no investment in the network – the decision to invest is purely one of return versus risk. However, economic regulation does provide a guaranteed, relatively risk-free cash stream to the owners.

[2] NEM objective as espoused in the NEL
[3] Issues Paper page 15

The third point has no bearing on investment by the network owner but more by upstream and downstream investors. If the costs of transmission are too high, then investment will not occur by generators or consumers. It should be noted that investment in the transmission network and in electricity generation does not enhance the national income (ie transmission and power generation is but a service to those generating the national income) which is what ultimately provides the improvement in the national well being. Over-investment in infrastructure does not provide net economic benefits to the nation.

Thus the transmission pricing must ultimately provide signals to consumers to invest. Historically each state has used its ownership of its electricity system to provide incentives for manufacturer/consumers to invest. However, in the NEM such regional encouragements are not intended to be present – that regional equity prevails. In the new NEM, such downstream investment signals should not be regional but based on the way the NEM as a whole provides.

This approach then leads to the issue of equity between consumers. The NEM was not built to serve one class of consumer, with another class able to benefit from the marginal costs of increasing capacity. The NEM is a service for all consumers and each class of consumers should pay for the use of it in proportion to the benefit it provides. Not to accept such a principle inevitably leads to the inevitable question as to which consumer class was the NEM constructed for?. If it was built for large continuous industry then domestic consumers would have little access; equally if it was built for domestic consumers then the NEM would be only available to large consumers at inconvenient times. Thus it is appropriate to assume that it was built for all consumers and this must be the basis for cost allocation between different classes of consumers and user types.

The Issues Paper attempts to provide guidance in this regard by stating

> "The NEM objective refers to the long term interests of consumers. One interpretation of this is that the Rules should be designed to benefit consumers, paying no attention to the distribution of benefits amongst consumers either on a class or a geographical basis." [4]

This integration is supported. At a high level, we believe that governments collect taxes and are responsible for the distribution of those revenues. There is no role for regulators on issues of social equity and redistribution. In addition, the Issues Paper encapsulates a view that is sufficient as far as it goes, but fails to address two elemental issues

1. the allocation between different consumer classes of costs for usage of the network must be undertaken and therefore a mechanism must be

[4] Issues Paper page 15

developed to allocate the costs equitably between consumers in proportion to their demand.

2. Generators are part of the NEM and therefore they must be responsible for sharing in the costs of the network. For a generator to not pay its share is akin to consumers paying for only part of a service, with the delivery of the product always being to the cost of the consumer, but where the source of the product is indeterminate.

Thus, when considering the cost of the network and the allocation of its costs to users, it should not be assumed that the current structure should continue to apply – ie that generators should pay only for "shallow connection costs" and the consumers should pay for all else. For the correct economic signals to be allocated to generators then there is a strong argument that these will be best provided if the generators pay for all costs of transport of their product to the consumer.

Thus the generator has correct locational signals relative to its customers, and consumers have correct locational signals relative to the costs of generation and delivery.

In this way a generator has the ability to assess whether an embedded generator adjacent to a consumer is more efficient than locating near the lowest cost fuel source – ie is it cheaper to deliver fuel to a generator located next to the consumer, or is it cheaper to deliver electricity by wire to the same consumer. In this way the consumer has the ability to assess whether it is cheaper to build near a generator and ship its raw materials in and ship its products out. Strong and accurate locational signals are required for such decisions to be made

4. Bearing in mind the NEM objective, should economic efficiency of the Rules be the focus or should it also have regard to the distributional consequences of Rule changes?

The Rules should accept that economic efficiency is the prevailing need. Considering the comments above, the NEM should be considered as being developed for all consumers. As the NEM is constrained by demand rather than usage (ie the load factor of the NEM is quite low), then the method of cost allocation should reflect the demand each class of user places on the NEM.

5. If the NEM objective should have regard to distributional consequences of Rules changes, how should these be taken into account?

Accepting that economic efficiency is the prevailing need, the next element of NEM objective must only have regard to distributional consequences in the allocation of costs between the different classes of user, for not to do so will result in incorrect economic signals being provided, as they are essential to identify the most appropriate method for overcoming constraints. The most appropriate method for addressing distributional consequences is by allocating the costs between different classes of users based on the demand they have, rather than on the volume of transport used. It is demand that sets the size of the each element of the NEM, rather than volume.

This principle follows the structure of the wholesale electricity market where it is the demand on the system at each half hour that is intended to set the price for electricity

The Issues Paper goes on to discuss the extensive work already undertaken. When referring to this additional work, care should be taken in accepting some of the conclusions "prima facie". As the review by the AEMC proceeds it will be come obvious that some of the previous work has not be undertaken with an open mind (and major users have some reservations), and that other work will be impacted by decisions made through this review process.

Experience in the NEM has also demonstrated that a number of the assumptions made in earlier reviews (eg the NECA transmission review commenced in 1997) has since been found to have limited value such as the work supporting the concept of market transmission interconnectors where (bitter) experience has shown this concept to be effectively non-viable, with those developed being either fully underwritten (as in Basslink) or converted to regulated status.

4. Current Transmission Pricing Regime

Network costs should be allocated as near as is reasonably possible to reflect the costs associated with the parties using the assets. Where assets are used exclusively by clearly identifiable users (generators and/or consumers) then these should be allocated to those who are the only beneficiaries of the assets.

Entry and Exit charges

Thus, where the assets are used only be a generator, then these should be costed to the generator; where they are used exclusively by a group of identifiable consumers then only these consumers should pay for the benefit of these assets.

In this way the costs associated with entry and exit from the shared network are clearly identifiable as are the customers of the service benefiting from these assets clearly identifiable. This allows clearly economic efficiency to prevail.

The only concern that this approach reveals is where the assets are oversized for the duty. Thus there is a need to ensure that the assets are properly and clearly optimised before any costing of assets is undertaken.

6. Is the allocation of network costs between the connection and shared network categories in the Rules broadly appropriate? If not, how could it be improved?

The principle of entry and exit charges is supported as this allows costs and beneficiaries to be matched, following the basic tenet of economic efficiency.

The only proviso is that assets must be optimised before costing of the entry and exit charges are developed.

Common service charges

There are some costs associated with the transmission network which cannot readily be allocated to a specific user, such as system operation, overheads, funding costs, and the like. These are referred to as common service costs.

The Rules should identify exactly what these costs are by category, and the regulator should verify that the costs so allocated are legitimate. This ensures that those services which are deemed to be common are the only costs allocated to this category.

The current approach is to allocate these costs to consumers on a volume (MWh) basis. Alternatives could be to allocate these on a route length of line, so much per substation or probably more appropriately on the demand each consumer places on the network (ie on a MW basis).

The demand (MW) basis reflects the actual stress put on the network by each consumer. Usage at low volume times places little stress on the network and requires much less attention than when usage is at high usage times, or when the network is near constraint. To apply the common service charges based on consumption allocates a greater share of costs to consumers using power on a continuous basis, and less on those using the network at times of high demand.

As it is high demand that drives the need for greater investment in the network (and with it the associated network planning, funding costs and careful management of the operation, then there are more aspects of the common service costs that are related to the peak demand on the system (ie that are driven by MW rather than by MWh). This is seen as being more economically efficient.

Thus, either the current system is followed (ie on a MWh basis) or some other basis is selected. As most costs are more related to MW it is suggested that this be the basis of cost allocation in future.

NEMMCo has developed a tool for assessing loads into the future (ie a forward looking basis) for allocating system losses. To do this requires an assessment of the future demand on various part of the network over each critical half hour. Using this tool could allow common service allocation on a forward looking basis rather than a basis related to demands placed on the networks in the past. This approach is closest to allocating costs to the user at the time, and is therefore more economically efficient.

However, generators cause as much need for common services as do consumers. Thus, to allocate all common services to consumers is not economically efficient. As the amount of generation equals the amount of consumption it would be appropriate and efficient for half the common service costs to be allocated to generators and half to consumers. As generators and their despatch is related to the demand on the system then demand also becomes an economically efficient basis

There is a need to consider the appropriate efficient allocation of costs between regulated and non-regulated activities, as the latter activity is increasing. There will always be a natural tendency for network service providers to cross-subsidise non-regulated activities, or even to inflate regulated costs.

7. Should a common service charge be maintained or should these costs be incorporated into another charge? If not, how should common service costs be allocated or incorporated into other charges?

There is no doubt that there are costs which cannot be allocated to specific users. Thus the retention of common service costs is supported.

Allocation of common service costs should be allocated on a forward looking basis, perhaps using the tools developed by NEMMCo to develop forward looking loss factors

Common services should be shared equally between generators and consumers, and a demand basis (MW) is more related as a basis for allocation than the current usage basis (MWh).

Generator and MNSP charges

Without the transmission network, neither generators nor MNSPs could provide a service.

In particular, MNSPs need extensive network connection support (at both ends of their network) as well as the transmission supports leading to generators and consumers in the two regions.

Equally, generators need the transmission network to deliver their product to the notional regional node, if not to a consumer located closer to the generator than the node.

The cost of those assets used exclusively (or almost exclusively) by a generator or MNSP should be allocated to the generator or MNSP as an entry cost. This would apply where the transmission line is long and not used significantly by any consumer. An example of such a transmission line is that used to transport power from the Gordon Power Station in Tasmania to Hobart. This provides a sound economic signal to a power station of the import of its selected location. This same principle applies to MNSPs.

The reason for this is that even though the power line connecting the generator to the nearest point where consumers are connected may have been assumed to be part of the shared network (because it had been built prior to disaggregation), on a comparative basis this would be now considered as a connection cost for the generator. An example of this is the power line connecting Gordon power station in Tasmania to Hobart. This power line is essentially only used by the generator to supply into the consumer network. Thus, if Gordon power station was to be built now, it would have to bear the connection cost of this power line as a connection asset.

Economic efficiency and equity to competing power stations requires the cost of this power line to be allocated exclusively to Gordon power station as a connection asset, at least up to the point where the first consumer is connected. As this consumer uses only such a small element of the power provided by Gordon PS then equity considerations would imply that the bulk of the power line cost from this point to Hobart would be allocated to the Gordon PS as a connection cost.

It should be noted that a consumer connection might be made to such an exclusive transmission line for the sake of convenience, and in such a case the allocation of costs might allow for a proportional share of the transmission line to be added to the consumer use of system charge.

8. Should generator and MNSP use of system charges remain a matter for negotiation with the TNSP or should they be prescribed in the Rules?

As pointed out in the Issues Paper, there are currently no use of system charges which have been "negotiated" between TNSPs and generators/MNSPs. This is because the Rules allow the TNSPs freedom to allocate all such charges directly to consumers through the acceptance of the existing network as the "shared network.

This thus permits existing generators/MNSPs and those utilising the existing "shared network" even though no consumers may be connected to the assets, a lower cost of connection than new generator developers. By definition an MNSP connects existing points between two separate shared networks, effectively for no charge, even though there may be no consumers connected.

As discussed above by not analysing the actuality of usage of the existing networks creates disparity between new and existing generators. Such disparity permits existing generators a commercial advantage compared to new generator entrants, and therefore permitting continuation of this practice cannot be seen as being economically efficient.

In addition to the Tasmanian example given above, another is the to 500kV power line in Victoria between the Latrobe Valley and Melbourne. Here the power line is used exclusively by generators who in turn benefit from having very low loss factors. A new generator entrant located (say north of Melbourne) would have to build its own large capacity power line to Melbourne to deliver its output. By allocating to generators directly the costs of the power line to the demand centre creates equity between existing generators and new entrants.

Customer usage charges

There is no doubt that effectively consumers ultimately the costs of transmission networks, whether paid for directly in network charges or indirectly through the cost of electricity when included in generator bidding. To allocate the network charges directly to consumers is the simplest way of recovering network costs, but by doing so it defeats the principles of economic efficiency.

Economic efficiency points to generators receiving locational signals and by new entrants not being disadvantaged compared to existing generators. Where a new entrant locates to be close to its consumers, it should obtain a full benefit for doing so. Currently an embedded generator does not receive the full benefit of its location and suffers due to a high transport cost for its fuel, but competes directly with a generator located remotely but which may have lower costs for its fuel due to its location.

An example of such a disparity is an embedded generator using biomass as fuel, such as in the sugar industry. The remote coal fired generator competes with the embedded generator directly in relation to bidding into the NEM. The embedded generator pays for connection costs within the distribution network and perhaps even for strengthening the distribution network to the main transmission substation. The current transmission cost allocation arrangement for the embedded generator only grants the benefit of a proportion of the transmission use of system charge, thus directly disadvantaging the embedded generator which also has other cost disadvantages due to its location.

This is despite the fact that the embedded generator is closer to its customers

Cost Reflective Network Pricing (CRNP) and modified CRNP

The Issues Paper lists six points which describe the way the CRNP allocates costs in order to reflect the complexity of electricity flows[5].

The only disagreements that MEU has with these points are at:-

- Point 1, the current allocation allows only 50% of the costs to be varied on a usage basis, allocating 50% of the costs to consumers on a fixed basis. To allocate costs where only a percentage of the costs is reflective of usage does not follow the principles of economic efficiency and further to do so distorts the locational signals required to ensure optimum location of generation and consumer.

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[5] AEMC Issues Paper page 26

- Point 2. Whilst the principle of cost allocation should be related to usage at peak usage, sharing the entitlement to capacity and the associated costs to all users in proportion to their need for the network, this is not the case for every TNSP. The TNSPs have the ability to select what usage times they wish, providing that such times include a minimum number of days where the usage of the network is at its peak. To move beyond the minimum number of times (as some TNSPs) do, increases the allocation of costs to those consumers who use the network regularly, and reduces the costs to those that use the network occasionally, despite the fact that it is the occasional users that cause the constraints in the network, and require it to be oversized to meet the needs of consumers for very short periods of time. This approach then fails to send the appropriate signals to those customers (generators and consumers) who only use the networks for very short periods of time.

The Issues Paper notes that the modified CRNP approach as currently used leads to connection costs being high for those consumers where there is a high available capacity. This should not be a problem if the network is costed on an optimized basis. An optimized basis prevents the payment for significant spare capacity by those consumers who are connected to part of the network which is over sized. However, it has been observed by consumers that the TNSPs and the regulators are loath to optimize the costs of the networks to the extent needed for CRNP to be used as a true cost allocation methodology.

A forward looking approach to cost allocation is supported and has been discussed above (using the NEMMCo tools used for assessing losses). It is only by providing realistic locational signals to generators, new entrant generators and consumers that there will be an active indicator for the relieving of constraints or preventing constraints from occurring in the future. Such indicators are already being used by the networks themselves for ensuring that supply is maintained.

An example of the failure to use a forward looking approach is where new generation has been built or new consumer conditions apply which if recognized would be more equitable to all concerned. To delay the benefits or penalties associated with such changes impacts on all consumers, and fails to reward or penalize the causer of the changed circumstances. A delay in appropriate allocation of costs by up to two years may deter a new entrant generator or penalize existing consumers unnecessarily. Economic efficiency requires that a rapid response to change is needed to ensure the appropriate response.

9. If a modified CRNP usage charge is to remain an option:

A CRNP or modified CRNP approach to cost allocation is seen as appropriate providing it is used to allocate costs to <u>all</u> users (generators and consumers) in proportion to their usage of the asset. It is only by using this that locational signals will result.

- **should the Rules prescribe the criteria for the AER to accept implementation of modified CRNP?; and**

  Yes. As has been seen already when left to the TNSPs, there are perverse outcomes that have been identified from the differing approaches used.

- **should any network customer (rather than just the TNSP) be able to request that the modified CRNP methodology be implemented?**

  Yes. However, once accepted then the regulator must ensure that equity is the result and that the change does not unfairly benefit one party to detriment of another

Customer General Charge

Where a cost cannot be clearly attributed to a specific user then (as with the common service charge) it should be allocated to all customers in proportion to the usage (demand rather than consumption) placed on the network.

The general costs to use the network and those other costs (such as the settlement auction residue) can be allocated either through either consumption or on a demand basis. As these costs (in similar fashion to the common service charge) are more related to the demand placed on the network due to the occasional high demands rather than the more stable consistent usage which results which results in a consistent demand but higher consumption. To allocate the costs more associated with the occasional high demand placed on the network on a consumption basis allocates a higher proportion of the costs to those consumers and generators which do not cause the occasional constraints which lead to the settlement residues and constraints.

Thus, these charges which are not attributable to a specific user should be allocated on a demand basis rather than a consumption basis.

10. How well do the CRNP and modified CRNP methodologies accord with efficient pricing principles? Could simpler approaches be applied to produce similar outcomes?

The current methodologies are distortionary and do not follow economic efficiency principles. The cost allocation for use of the transmission network should

1. Allocate 100% of the use of system costs, not 50%
2. Should be forward looking rather than up to 2 years behind reality
3. Should recognize that the cost of oversized assets should be optimized to the demand actually to be incurred (using forward looking techniques)
4. Should be allocated on demand and not on consumption

11. If the CRNP and/or modified CRNP methodologies were to be retained are the descriptions of the methodologies in the Rules sufficiently detailed and clear? If not, how could they be clarified?

The Rules must be more specific as to how the cost allocation must be carried out and the regulator be required to verify that the TNSP has followed the

Treatment of TUoS Discounts and Rebates

As it has been agreed that TNSPs should be entitled to a revenue cap then it is in the interests of customers for the TNSP to maximize the contributions from as many customers as is possible to minimize the costs to all.

A bypass is a tool for a customer to place pressure on a monopoly to secure lower charges. If the bypass is permitted, then all revenue from the provision of the service is lost. This could result in either higher charges for all other customers, and/or an optimizing downwards of the value of the assets bypassed causing a reduction in the revenue to the TNSP. As the optimizing of the assets will only not impact other customers if the assets are stranded, it is most likely that in most cases of potential bypass, all other customers will be negatively impacted. It is therefore in the interests of consumers that some contribution is received from the potential bypass opportunity rather than no contribution if the bypass is performed.

Where a legitimate opportunity exists for a TNSP customer to bypass the transmission system, then an analysis should be undertaken to ensure that the likely loss in revenue after allowing for the optimization of the assets will be greater than the discount needed to prevent the bypass. This must be reviewed by the regulator acting in its independent role. Such an approach is economically efficient and equitable to all customers

The element of the optimization must be taken as a loss to the TNSP as this is one of the few risks it faces for its relatively high return on assets.

12. Is it appropriate to provide scope for TUoS discounting in the Rules?

Yes.

13. If so, could the existing arrangements be refined and how?

To have a firm percentage of a "safe harbour" is not economically efficient. Each potential bypass must be assessed on its merits as each set of circumstances is unique, and the TNSP must accept as a loss the reduction of the value of the assets resulting from optimising after the loss of demand is incorporated. The three estimates of cost (loss of revenue, saving from optimising and discount needed to prevent bypass) need to independently verified by an independent party.

To carry out a unique assessment does not result in a significant amount of work as opportunities for bypass are not frequent.

If the NEM is to strongly support demand side responses, then the full value of a demand side response must be incorporated. There is no doubt that an embedded generator does provide greater security for the NEM and for consumers. The current Rules actively discriminate against embedded generation and consumer responses by not providing for the full value of the reduction in demand or for the embedded generation.

The opportunities for embedded generation are relatively infrequent, and each opportunity has unique features. Further embedded generation also has the potential to provide for the relieving of network constraints, and for reducing other electricity costs to all consumers. Thus the full value of embedded generation should be assessed and balanced against the potential costs which consumers will be exposed to by the granting of any rebate. The rebate should not exceed the equitable re-allocation of all transmission costs appropriate to the notional reduction in demand. The rebate should include the full saving of usage charges, and not discounted by a notional percentage such as the 50% currently allowed.

Thus, it is suggested that each opportunity is assessed on its merits rather than setting fixed rules for assessing the benefits and costs to a TNSP. This can only be carried under the auspices of an independent party.

14. Is it appropriate to prescribe arrangements for TUoS rebates in the Rules? If so, could the existing arrangements be refined and how?

The rebate should be fixed at a maximum of the full change in the usage charges resulting from the embedded generator or demand side response. The minimum value for the rebate should reflect the unique circumstances surrounding the embedment. The assessment of the rebate should be carried out under the auspices of an independent party such as the AER.

15. Do the current pricing arrangements appropriately cover alternatives which contribute to the avoidance or postponement of transmission augmentation?

No. See comments above.

16 Should TUoS rebates also apply to generators connected to the transmission network, DSM or other non-electricity options?

Yes. Embedded generation is only one option of the range of demand side responses. Any demand side response which delivers the same outcome as embedded generation should be granted the same commercial benefit

Does this depend on whether generators generally pay shared transmission costs?

Embedded generators do not pay transmission costs. This only applies to generators connected directly to the transmission network. Embedded generators provide for a reduction in the demand at a transmission substation, rather than export, and therefore do not incur transmission costs.

Where a transmission substation exhibits both import and export of power, then the export element of the power must be considered as if it were a generator for that period of time and pay transmission costs for this period as if it were a generator. Such a approach is both consistent and economically efficient.

5. Efficiency and Transmission Pricing – Key Concepts

The Issues Paper provides a succinct development of the issues surrounding the use of both SRMC and LRMC cost allocation methodologies on an electricity transmission network.

Whilst attention to the investment decisions for generators and TNSPs is used as the focus of the AEMC assessment, as usual, the investment decisions (and therefore the ability of the consumer to respond to price signals) of the consumer is overlooked. When the fact that consumers have invested considerably on the expectation of a long term secure supply of electricity to support the investment by the consumer, this investment must be taken into consideration as well. When this point is added to the mix, then perhaps an alternative conclusion is generated.

The MEU agrees with most of the points made in the Issues Paper on the issue of LRMC and SRMC, except that associated with the cost of constraints. The cost of a constraint must be the least cost related arising from three options – the value affected consumers will put on the loss of supply or of the non-supply of electricity, the cost of providing additional generation at the point of demand causing of the constraint, or the cost of building new transmission assets.

This issue then must consider the duration of time the loss of or non-supply to a consumer can or will be tolerated. Whilst occasional short term losses of supply might be tolerated by a consumer, as electricity supply is now an essential energy medium, in the long term the consumer must have a secure supply or move. Bearing in mind that the cost of moving will be significant (whether for a domestic consumer or a large manufacturer) because of the investments made by the consumer, then the cost of a constraint must be assessed by the consumer over the duration of its investment. To move home (for a domestic consumer) or a large manufacturing plant is an expensive activity and therefore the decision to invest must be taken as a long term decision, implying that the consumer investment also is a long term action. As a minimum it must be accepted that the decision by a consumer to invest would be a minimum of the 15 years allowed by the ATO to depreciate manufacturing facilities. The other methods to relieve that constraint by building of a new generation facility or network augmentation both require significant time (>15 years) to recover the investment.

Thus, despite the Issues Paper stating that relief from constraints is a SRMC issue, there is a sound argument which implies that it may be just as much a LRMC issue, and one having a duration of at least 15 years.

With such an issue being removed from the SRMC of a network operation, the SRMC values which would then only include for losses and some other minor operating expenses are extremely modest at best.

17. Should transmission pricing arrangements principally seek to promote efficiency in the short or long run?

In considering the points made above, it would seem that on balance the transmission system should allocate its costs on a LRMC basis rather than on a SRMC basis. It becomes not feasible to value constraints on a SRMC as the implications to consumers must be seen both in the short term as well as in the long term in order to generate an appropriate value

18. If transmission pricing arrangements should consider both the short and long run, what approach should the Commission take to determine the appropriate balance between these aims?

The SRMC aspects of the transmission network do not provide sufficient indications of the costs of constraint to provide a clear signal to the TNSP or consumers.

6. Relevant NEM Context

The NEM is predicated on all generators and consumers having access to the networks, but if there is a constraint, this will limit access to new entrants. Further, there are no guarantees available for any network customer (supply side or consumer) to continuous access as there are instances where the network owner cannot and should not be responsible for failure to supply.

Generators consider that they require firm access in order to sell their product, yet the generators have the power (and use it) to withdraw supply for commercial gain. In such an instance, consumers are directly impacted (due to high energy prices) and network owners are negatively impacted due to the lower usage made of their networks when high prices abound. Thus, for the generators to require firm access yet use their rights not to supply would appear to be a contradiction and rather self serving.

From the point of a consumer, for a TNSP not to provide access to a generator should result not only in the loss of payment from the generator, but to share the costs the consumer incurs as a result of the lack of this access. If a generator wishes to have firm access to the network, then it should pay for this and not expect the cost to be borne directly by the consumer as currently network charges are constructed. If this firm supply arrangement for a generator is replicated as faced by a consumer, the consumer is expected to pay for this firm supply arrangement itself, and not rely on other consumers to provide this unique feature.

What is missing from the Issues Paper discussion is that there must be pressure on the NSP to ensure the maximum availability of the network at times when it is most needed. This matter is currently under review by the AER Service Standards Working Group. In the absence of any such incentive, it must be accepted that the NSP will use reasonable endeavours to have the network available for most of the time.

Thus, the decision to invest as a generator or consumer where there is a constraint in the network must be made in the full knowledge that the benefits arising form the selected location outweigh the detriments of having to augment the network to overcome the constraint. As there must be other benefits from selecting such a location, it is not equitable for the costs of such augmentations to be levied on other customers.

The Regulatory Test (RT) is a tool for assessing whether an augmentation will benefit a wider customer base than just the direct beneficiaries. For example if a new generation facility will reduce the overall cost in the energy market would be seen as a reason for all consumers to support the augmentation. This example highlights that as consumers pay directly for the bulk of the network costs, then augmentation of the network is an active tool for reducing generator market power and controlling energy prices. Despite this clear logic the RT as established by the ACCC does not recognise the benefit of lower energy prices in a region caused by network augmentation, commenting that such inclusion would distort the NEM and only achieve a “transfer of funds” between on part of the NEM to another. Such an argument has validity if, and only if, the two parts of the NEM contribute equally to the provision of the network. As consumers pay the bulk of the network costs, then benefits which accrue to consumers (even at the loss to generators) must be seen as a contributing factor within the RT calculations.

Thus, despite the Issues paper propounding that the RT can be a tool for assisting in the sensible location of generation, this should not be the case. Rather the RT should assess whether consumers will benefit by reducing the price of energy. The example provided by the Issues Paper[6] only compares between an embedded generator and a remote generator. As noted earlier, the signals available to an embedded generator are already muted.

If a generator is required to pay for the connection costs (to the nearest part of the shared network) and for the relief of constraints that it will cause to ensure that it can be dispatched then this presupposes that the existing generators have prior rights to the shared network. Yet it is consumers that pay directly for the bulk of the network costs. Thus where there are a number of generators competing for the right to use the constrained network, it should be that the generators themselves should pay for the augmentation and not consumers.

Until there is either freedom for consumers to select the location of generators, or that generators pay for access for transporting their product to market it is inequitable for consumers to pay for generators’ unconstrained access.

The current arrangements for connection of new consumers or for increasing demand for existing consumers connected to the NEM require the consumer seeking the increased access to pay directly for all of the augmentations needed (including deep connection costs) before the investment is made. This sends the appropriate locational signals to consumers. In a like manner the same locational signals should apply to new generation, and unless the new generator can prove that its connection will reduce the cost of energy in the NEM (ie benefit all consumers in that region) then it should pay its own shallow connection costs and in concert with the other generators connected at the same point pay for the deep connection costs in order to relive the constraint and permit (for most of the time) unfettered access for all of the output of the combined generators.

[6] Issues Paper appendix 1

19. To what extent are existing signals from other aspects of the NEM arrangements (or requirements from regulatory settings outside the NEM) sufficient to promote efficient behaviour by actual and potential consumers and producers of electricity in the short and long run?

The current signals are insufficient and create distortions (eg not all TUoS saved goes to an embedded generator, consumers pay the bulk of TNSP costs, generators connecting to the transmission network only pay shallow connection costs, the RT excludes the benefit of reducing energy costs by increasing generator competition). Until these and other distortions are removed the principles of economic efficiency cannot be readily applied.

The Issues Paper is correct to identify that DNSPs do not necessarily pass though the TNSP locational signals. Further, retailers bundle energy prices by combining transport costs with energy costs which further dilute the TNSP locational signals. It is those consumers directly connected to the transmission system and some other very large consumers (where pass through provisions apply) which see the locational signals. Unfortunately these direct connected and large consumers invariably have very high load factors relating to their usage of electricity and therefore are not the main causers of the short or even medium term constraints. Thus the TNSP signals are being sent to the wrong consumers.

It is interesting to note that TNSPs are all moving towards demand based charges. This is an obvious move as it is demand which creates a network constraint. Unfortunately, most DNSPs persist in allocating their costs more towards consumption than demand. Even consumers with a demand meter still have a significant portion of their DNSP costs allocated using consumption. This approach provides an even greater dilution of the TNSP locational signals

Notwithstanding this it is still important that signals do exist. The DNSPs can and do react to the TNSP signals and attempt to redirect their new entrants by various other (and not necessarily price) signals. It is Governments who have often required that there be equality (not necessarily equity) between consumers of the same class regardless of the economic implications of these decisions, yet are also susceptible to the threat of power shortages. Accordingly they also bring pressure to bear on the DNSPs to provide non-price signals to consumers.

Equally it should be recognized that of all of the costs consumers have to bear in the aggregated cost of electricity, the cost of transmission is the smallest significant element. Energy costs per MWh are 2 to 5 times the cost of transmission, and in most cases distribution costs are of a similar magnitude. The costs of retailing risk margins can vary by 1to 5 times the cost of transmission, although for certain load profiles may be less than 1 times.

When put into this context, the TNSP signals for location of consumption will be perforce relatively modest, even without the dilution effect of distribution and retailing on the locational TNSP signals.

In contrast the locational signals to new and existing generation are much higher, particularly as generators make little contribution to the TNSP costs. If generators are levied with the full cost of connection and usage of the network, then these signals have much greater use. When such signals are provided to remote generation, and embedded generation is provided with the full benefits of its location, then this will partially redress the current imbalance between remote and embedded generation.

20. Given current distribution network pricing arrangements, is it appropriate to prescribe transmission pricing structures in the Rules?

Yes. See comments above, particularly in relation to new and existing generation

21. If so, should prescription be limited to prices for particular network users?

No. Signals should be provided to all customers, be they large consumers (directly connected or with pass through), generators and DNSPs. Without accurate signals provided to all significant users then the principles of economic efficiency will be so muted to the extent that they provide little value at all.

Further, unless there is consistency in the way the signals are developed and presented, then there will be distortions between different regions due to the different approaches used by the different regional TNSPs

7. Allocation of Regulated Revenue across Transmission Users

Shallow or Deep connection costs

There is no doubt that the costs of shallow connection should be borne by the generator connection to the network. These assets are effectively dedicated to the generator and are not used by any other party.

The issue of the allocation of deep connection and the prevention of "free rider" status is an issue wider than just generation and covers the principles needed behind MNSP "overlays" as well. For example an MNSP might look to use the spare capacity in a TNSP owned network by a low cost method of relieving a constraint. It would then be effectively charging consumers for use of assets already paid for by consumers. Such an example concerns the application by an MNSP to add a new transformer to the SAVic connection and utilize the spare capacity in SA and Vic feeders and so charge for the regional differential when SAVic was constrained.

To require the new entrant to pay for all of the shallow and deep connection costs implies a degree of ownership of existing capacity by existing generators. This is then a barrier to new entrant generators. The deep augmentation provides a benefit to all generators connected, not just the new entrant.

To ensure that the costs of upgrades are paid for by the beneficiaries requires that a new entrant should not pay only for its usage of the augmentation but also of the existing assets. If the existing generators paid for the use of the existing assets then, just as applies for consumers, they would be levied the augmentation in proportion to its usage. Currently consumers pay the exit costs (shallow connection) and for all shared transmission costs. If a feeder is upgraded to support new consumer entrants (deep connection) then all consumers using the upgrade pay in proportion to their usage. This same principle can apply to generator connections but only if they pay for the assets they use to get their product to market.

For the sake of convenience, the NEM is divided into regions, with all power assumed to pass through the regional node. Usually this node is the point where most of the regional demand is served. This approach is a tool for allocating costs of transmission losses, but also for establishing a single regional power price which is then paid by each consumer in the region.

If generators were allocated the costs of delivering their power to the regional node, then any augmentation (other than the specific shallow connection costs) to the associated transmission network to accommodate new entrants could be allocated to all benefiting generators in proportion to their usage. Such an approach would enable true competition between generators, provide clear signals reflecting their location in the network, and eliminate some of the disadvantage faced by embedded generators who would not then be exposed to any transmission costs.

Generators would bid for power supply at the regional node (rather than at the generator connection point) and the transmission network owner would provide each year the cost for the generator to include in its bidding pattern. Such an approach replicates the way consumers are levied for the costs of using the shared assets. Whilst there are still anomalies that would flow from such an approach, it does provide for strong locational signals for generators, it does not diminish the competition between generators, it provides a solution for allocation of deep connection costs, and replicates the way consumers are currently exposed to transmission costs.

Such an approach might also impact on the resistance in some quarters currently identified to increasing the numbers of regions in the NEM

25. Is a deep connection approach compatible with the open access transmission regime of the NEM (which is not a subject of the present Review)? If so, how should potential "free-rider" effects be managed?

Open access is available to all generators. It is the cost of such access that needs to be resolved. The MEU proposal provides a solution to the many vexing issues currently extant in the NEM

Shared network charges

The current approach in the NEM has been to minimize the numbers of regions. By doing so, Governments have been able to ensure that similar classes of consumers pay similar costs regardless of location. The outcome of this approach is that there are few locational signals available for siting of new generation and new loads. Despite this there have been a (very) few examples of new (usually very large) loads attempting to locate adjacent to existing generation in order to exclude all transport costs. In contrast very few generators have attempted to locate near load centres, content to locate near to the fuel supplies as they suffer little or no penalty from not locating near the loads. Generators that have attempted to locate adjacent to loads (such as embedded generators) have suffered financial discrimination.

There is no doubt that the current arrangements do not provide any incentives for generators to locate near loads and as they only suffer connection costs and no shared network charges, they have located where to suit other drivers. Thus, efficiency in the NEM is being undermined by the lack of strong locational signals

The approach by NECA in examining changes related to new generation and investment in the network does not address any of the fundamental problems facing appropriate locational signaling, as it essentially grants prior access rights to existing generation. As long as there is discrimination between existing and new entrant generation, and discrimination against embedded generation with relation to network cost allocation, then there will continue to be, a lack of dynamic efficiency in the NEM.

The issues paper points to the regional structure of the NEM, non-firm access to generators and investment controls (eg the Regulatory Test) as providing effective locational signals. Unfortunately the approach to developing more regions (and so greater efficiency) has been undermined by State interests, and the Regulatory Test and other mechanisms fail to recognize the imbalance between those paying for the network and those seeking to minimize augmentation of the network to increase competition.

22. Should NEM connection charges continue to be based on a shallow connection approach or should a deep connection approach be adopted?

No. Generators could pay for the transmission costs up to the regional node. Augmentations (deep connection costs) would then be paid by all generators receiving the benefit in proportion to the usage by each

23. If a shallow connection approach is broadly to be maintained, are there any circumstances where connecting parties should pay for up or downstream upgrades to the shared network?

Shallow connection costs should be paid by the generator connected, but the transmission cost to the regional node and other deep connection costs in getting each generator's products to the regional node should be allocated on a usage basis.

24. If a deep connection approach is to be adopted in the NEM, how should it be formulated?

See comments above

27. Are there reasons why generators should make some contribution to shared network costs?

Yes. Refer to commentary above

If so, what approach should be used to determine the share of shared network costs should be paid by generators?

Generators should pay for the costs of the transmission assets to the regional node, just as consumers do. Any augmentation to permit a new entrant should be paid for by all benefiting generators in proportion to their usage. Where such assets are used by both consumers and generators, the costs should be allocated in proportion to the demand

CRNP and LRMC

It is accepted that the LRMC of the network must be recovered to ensure that a reasonable return is available to investors of what is essentially a capital intensive monopoly asset. If the LRMC (as opposed to SRMC) is not recovered there is no incentive to invest in the network and as there is no tool available to provide competition other than regulation, then the recovery of costs must reflect the long run cost to supply the service.

The issue then becomes one of whether the long run cost should be recovered on a fully locational basis or on a part locative basis and part postage stamp. Once this decision is made then should the costs be recovered on a consumption or a demand basis.

There is no doubt that the efficiency of a full locative basis provides the maximum signaling. The decision to have part locative and part postage stamp is one of Government decision that consumers of the same class, regardless of location should pay the same cost. This Government decision mutes the locational signaling for efficient location of generation and loads.

The Issues Paper highlights the concern that as investment in networks results in significant over capacity once built, that CRNP will levy on the directly connected users a cost which is not required in the short term. However, this matter is no different to the sensible approach currently used where the costs are allocated on the optimized replacement costs regardless of the amount of depreciation that may apply to parts of the network. The approach assumes that all assets have the same age when allocating costs. This means that when an elderly part of the network is replaced, those users directly connected do not see a price rise which would otherwise apply if the assets were allocated on a depreciated cost basis. If costs are allocated on an optimized usage basis rather than a capacity basis, then the short term overcapacity of one section of the network is effectively shared by all users.

By using such an approach the CRNP calculation reflects the LRMC. The use of the modified CRNP closely replicates the process suggested above and is therefore supported. The Issues Paper points to arbitrary discounted percentages for utilization factors in the modified CRNP. In fact the use of such discounting factors is not necessary as some TNSPs already use ½ hourly data in the development of their shared network charges. NEMMCo does likewise with its development of the forward looking estimates of system losses.

The main problem seems to revolve around the decision to discount CRNP by 50%, having 50% of the network charges postage stamped in the assumption that to do so will result in an approximation of LRMC. As the approach suggested by MEU above (that of using optimized replacement cost combined with a forward view of usage of the network elements) as the basis of the cost allocation then there is no need to discount the CRNP by 50% to replicate the LMRC values

The only drawback with all of the approaches discussed in the Issues Paper and as recommended by MEU, is that none of the approaches provides a price signal for the relief of constraints. The current review by the AER Service Standards Working Group does lead to some indication of these constraint costs. Once the constraint is identified and relived, the costs can be integrated into the MEU model for cost allocation.

The discussion in the Issues Paper revolves around the difficulties that are the result which architects of the Rules saw with relation to multiple calculations being carried out. It is now possible to quickly develop energy pricing in many more regions, it is possible to calculate TNSP cost allocations for every half hour of every year (as ElectraNet does), it is possible to calculate forward looking usage estimates (as NEMMCo does for setting forward looking losses) and it is possible to input a number of scenarios in order to calculate the most likely of outcomes. With this potential to quickly and readily carryout much more complex and repetitive calculations, many of the reasons for not doing so (which was the main problem faced during development of the Rules in the early 1990s) have now disappeared.

28. Is the current shared network charging regime the best approach for achieving the NEM objective?

No. Actual experience and observation supports the view that the absence of any generator locational signals has not led to the expected building of generators adjacent to load centres. In fact there is active discrimination against such occurring

If not, what improvements could be made?

See comments made above.

29. Are there arrangements operating in other jurisdictions for the recovery of shared network costs that would be more appropriate for the NEM? If so, which jurisdictions and which aspects of their arrangements would be appropriate for the NEM?

The recommendations made above follow the lead set by a number of overseas jurisdictions. There is no reason why the NEM cannot follow these proven approaches

Discounts and rebates

MEU views on discounts and rebates were discussed fully in section 4 above. In summary, rebates for avoiding bypass and discounts for encouraging embedded generation are supported. However, whereas the current rules leave the setting of these in the hands of the TNSP, MEU does not support this approach.

The frequency of these opportunities is so low that there is no reason for the TNSP to have unfettered control of these. As the implications of the outcomes of bypass and embedded generation are significant to all consumers, independent assessment is essential.

30. How much discretion should TNSPs have to discount charges?

None. Any and all applications for discounts should be assessed by the TNSP with the consumer, and then a recommendation made by the TNSP to the AER. The AER should verify the valuations used by the TNSP and seek advice of the bypass savings from the consumer. The AER should then decide on the value of the discount.

31. Should TNSPs be entitled to recover the cost of discounts from other loads?

The TNSP should be able to recover the full discount less the loss resulting from any optimization of the existing network if the bypass was to occur. This amount should be recovered from all consumers.

32. Should any conditions for recovering the cost of discounts from other customers be prescribed in the Rules or left to the AER to determine?

The principles for valuing discounts should be detailed in the Rules and the AER should apply the principles to derive the maximum discount that might apply.

If so, what should be the general content of these Rules or AER discretions?

The discount should be related to the potential savings that the consumer may be able to generate by bypassing, and the reduction on the optimised value of the assets after bypass would have occurred. The TNSP should bear the cost of the value reduction resulting from the optimisation and all other consumers the net value of the proven savings less the optimisation. The AER should satisfy itself that all of the costs and savings are legitimate.

33. Should avoided TUoS rebates be retained in the Rules or left for negotiation between the DNSP and connected party?

The principles behind the valuation of rebates should be detailed in the Rules. The AER should assess the valuation of the rebates, accepting inputs from the TNSP and the embedded generator developer acting as independent arbitrator.

34. Is the appropriateness of TUoS rebates contingent on whether generators pay shared use of system charges?

The rebate is payable for the reduction in demand at a load connection point caused by the operation of an embedded generator. It has no relation to the costs associated with connection points.

If generators pay for the transmission assets up to the regional node, consumers will only pay for the use of transmission from the node to the point of consumption. Thus if this approach is followed the embedded generator would only reduce the transport costs between the node and the point of consumption.

35. If TUoS rebates are retained, what charges should they comprise?

8. Structure of Prices

As discussed earlier, the pricing approach for transport services should act to require users to pay in proportion to the usage they have at peak times. Thus the principle in the current Rules that TUoS be allocated in proportion to usage on the ten peak system demand days reflects the <u>right</u> of access by users to the network, regardless as to whether they exercise their right or not. Effectively a network is constructed to handle the maximum demand and not the consumption of energy. Thus, if a user wants to ensure that they can use the network when they elect to do so then the equitable method for allocating usage is on a demand basis.

A demand basis is economically efficient as it will drive the user of the network to increase its load factor (ie the relationship between peak demand and average demand) to maximize the load factor. A low load factor consumer effectively uses the network occasionally but at a high demand when it is used. This results in the capacity of the network being larger but with a low throughput.

Conversely a high load factor user will have a more consistent demand and its peak demand will be only marginally higher than its average demand. This approach uses the network in accordance with its design parameters and has much less idle capacity. Efficiency implies minimizing idle capacity.

Postage stamping of use of system costs is inefficient (although easily calculated) as it sends no locational signals, does not provide constraint cost indications and does not reflect the amount of capital tied up in providing the service.

Allowing the TNSP to decide which method it desires for pricing structure does not necessarily result in the most appropriate method for providing the correct signals implied by the Rules. The TNSP wants its AARR and how it gets this will be to suit the TNSP and not the NEM or consumers. To ensure the NEM needs become the driver of network pricing structure requires the Rules to be explicit as to what is required and how this is to be achieved. The AER can then direct the TNSP in the outcomes required and the method to secure these outcomes.

The efficiency of the NEM is too important to leave to the whims of the TNSP, even to the extent of the TNSP interpreting the outcomes the Rules might declare. It should be remembered that at the time the Rules were developed, it was assumed that all TNSPs would remain in the ownership of the State governments. With this oversighting by government it was assumed that TNSPs would act to reflect the ‘higher’ public interest needs identified by their governmental owner. As some TNSPs are now privately owned, it is essential that the TNSPs are directed in the way the transmission pricing structure is to be prepared.

36. To what extent is it necessary or worthwhile to prescribe transmission pricing structures in the Rules in order to promote the NEM objective?

As some TNSPs at least are privately owned, it is essential that the outcomes desired of the NEM are not left to the whims of the TNSPs. Thus the Rules must be explicit as to the required structure of the pricing approach and the AER must be required to ensure that the TNSP has followed the requirements of the Rules.

37. Would it be appropriate to provide guidance to TNSPs on what pricing should achieve instead of prescribing the structure? If prescription is required, which charges should have price structures prescribed in most detail?

No. To do so will leave the potential for different interpretations as to how each TNSP will structure its pricing. Pricing signals are too important to leave to a party which does not necessarily have maximizing efficiency of the NEM as its core driver.

It must also be noted that the TNSP has the augmentation of the network as its prime driver, as it is by this method that it will increase revenue and profitability for its shareholders. To leave pricing structure to the TNSP invites the TNSP to structure its prices to maximize its opportunities to use network solutions in preference to other methods for reducing constraints.

38. Should the degree of pricing structure prescription vary depending on the relevant class of network user paying the charge? If so, how could this be implemented?

To ensure efficiency the pricing structure must deliver the necessary and desired outcomes stated or implied by the Rules. Already direct connected users and large consumers (where transmission cost pass through is required) are exposed to locational and other signals. For smaller consumers these signals get muted by DNSP pricing structures and further again by retailer pricing structures.

As a minimum DNSPs must be exposed to the transmission pricing signals, and the extent that they are passed through to their customers should be evaluated by their regulatory Rules. It would be expected that DNSPs would advise their customers as to the implications of the decisions they make and the cost penalty resulting. If governments decide that small consumers should be protected from locational signals then such decisions should be clearly and openly stated and community service obligation (CSO) arrangements made via Budget allocations. The DNSP can then implement these governmental decisions.

39. How much discretion over charging structures should be left to the TNSP and the AER?

TNSPs should have no discretion as they have other drivers which could drive them from the best pricing structure solutions. The AER should have only minimal discretion where the TNSP can clearly demonstrate that the prescribed method cannot apply in a set of given circumstances. The exercise of such a discretion should be clearly detailed along with the reasons behind it and the particular circumstances which have led to the exercise of the discretion.

9. Pricing of Non-prescribed Services

Negotiating with a monopoly is extremely difficult. The Australian Competition Tribunal (ACT) in its recent decision on regulation of Sydney Airport pointed out that:-

> "In the absence of declaration, we are satisfied that any commercial negotiations in the future as to the non-price terms and conditions on which the airlines utilise the facilities and related services at Sydney Airport are likely to continue to be protracted, inefficient, and may ultimately be resolved by the use of monopoly power producing outcomes that would be unlikely to arise in a competitive environment."[7]

A number of MEU members have attempted negotiations with TNSPs and can support the view that negotiating with a monopoly is as the ACT describes in its decision. Further, unless the counterparty has significant financial resources, the monopoly can effectively prevent any action that it does not accept or agree with by resorting to expensive and legal approaches. Such an outcome does not engender a harmonious and jointly beneficial outcome.

The fact that generators and MNSPs have not negotiated any charging agreements with TNSPs (as confirmed in chapter 4 of the Issues Paper) leads to the assumption that negotiating with TNSPs is fraught with difficulty. An example of such challenges in negotiating with a TNSP is where a potential transmission agreement for connection of a consumer ran to nearly 120 pages, whereas a similar agreement with a DNSP for a similar service comprised less than 50 pages.

It is a fair to state that TNSPs will not provide enhanced service standards or firm access to its network. The reasons for this are quite reasonable. But because of this lack of ability of a TNSP to provide such services leads to the outcome that although TNSPs are required under the existing Rules to cost such services their inability to do so makes the inclusion in the Rules somewhat academic.

TNSPs are only required to have such excluded services reviewed under mediation and arbitration with NEM Participants. The term Participants excludes almost all consumers. Thus consumers, even those directly connected to the transmission network, are prevented from accessing the mediation and arbitration provisions of the Rules.

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[7] Australian Competition Tribunal: Application for review of the decision by the parliamentary secretary to the treasurer dated 29 January 2004 in relation to the application for declaration of the airside service provided at Sydney airport by Virgin Blue Airlines Pty Limited, clause 477

40. Are the negotiation provisions in the Rules regarding prices for non-prescribed services appropriate? What difficulties (if any) have been experienced?

Consumers have little ability to "negotiate" with a monopoly. Further, although the Rules permit a third party to build and operate a transmission element connected to an existing TNSP, the reality is that for small augmentations (such as a consumer might desire to connect directly to the transmission network) its is impossible to get a third party to carry out this work, due primarily to the constraints of operating a very small inset network far from its major assets.

41. Should Rules provide criteria in relation to pricing outcomes for non-prescribed services?

Yes. The transmission network is a monopoly. Even non-prescribed services need to be efficient and as the monopoly can control the "negotiations" there should be some criteria that the mediator/arbitrator should use to ensure that the outcome is efficient.

42. Should a price monitoring regime be considered for non-prescribed services?

If the AER has acted in its mediate/arbitrate role for consumers, then continuing oversight for the term of the agreement is probably not necessary unless the consumer desires it. However, at the time of renegotiation the presence of the AER or some pre-determined principles set by the independent supervisor are essential to ensure that negotiations are facilitated and the renewed agreement is efficient.

43. If so, what criteria would be appropriate? Would these be the same for all non-prescribed services?

See above comments. There is likely to be variation of requirements for continuing oversight between differing non-prescribed services. It should be left to the AER to determine the extent of any continuing oversight.

44. Are the current dispute resolution provisions in Chapter 8 of the Rules appropriate for disputes over pricing of non-prescribed services? What (if any) alternative dispute resolution processes may be appropriate?

Almost all consumers are prevented from accessing the mediation and arbitration elements of the Rules. This needs to be overcome and it is suggested that the AER be empowered to mediate/arbitrate in issues between TNSPs and consumers where the consumer is not a Participant.

10. Inter-regional Issues

Existing arrangements

The interconnection of the regions is the most fundamental aspect of the NEM. Without it, there is no NEM and regional generators can have unbridled market power. Therefore inter-regional connection provides a benefit to all consumers and benefits other generators which then have access to markets which they would not otherwise be able to access.

The existing arrangements show significant inconsistencies, and allocate responsibilities to those not involved. That the Victorian and South Australian governments (as distinct from the two network owners) are responsible for the negotiated reimbursement arrangement for the Victorian assets used for the net inflow of power from Victoria to South Australia, would appear to be inappropriate for a network arrangement that is intended to be independent of regional government involvement. That no other similar agreement exists for transfer of power between the other four regions attests to the lack of direction provided by the Rules relating to this matter.

The current arrangement is made even more absurd by the fact that the importing region is allocated the proceeds of the residue settlement auction – why should the importing region receive the benefit of the sale of the residue but still not have to pay the exporting region for use of its assets which enabled the transfer of power? At the very least the exporting region should receive the benefit of the residue!

The issue of payment for use of another region’s assets is somewhat complicated by the difficulty in identifying what assets are really used and to what extent, as AC power flows cannot be readily allocated to specific assets, and if there are reverse flows how these are to accommodated.

The fact that consumers in a region benefit from the ability (even if it is not used) to transfer power into the region, provides some competitive pressure on the regional generators from the threat of price pressure from generators in other regions. Whilst this price pressure is real, it is impossible to quantify. Thus, even though a region may be a net exporter of power, the regional consumers still benefit from the very existence of the interconnector.

Equally generators in a region benefit from being able to export to other regions. A low cost base load brown coal fired power station has difficulty in quickly responding to demand changes and has limited turn down capability. This means that if the regional demand falls, then such a generator benefits from a wider market. In a like manner a peak loading generator in one region can provide its service to another region, made possible by the presence of the inter-connector.

45. Could the current provisions in the Rules regarding inter-regional TUoS payments be improved?

Yes. See comments above and following

If so, how?

The current arrangements reward importing regions for using assets located in other regions and paid for by the other region's users. As a minimum the auction residue should be allocated to the exporting region as part reimbursement for the use of its assets.

46. What are the impediments, if any, to reaching interregional agreements?

There is no incentive for a TNSP or the regional government to develop such arrangements. The fact that there is only one such agreement attests to this. Generators do not want to pay any TUoS (including inter-regional connection costs) so there is no incentive for generators to want to establish agreements for this purpose. Consumers are not considered as NEM participants and are therefore levied the costs as no one else will.

47. Should the Rules provide criteria for determining the 'extent of use of a network'?

Yes

If so, what criteria would be appropriate?

See the discussion below

48. Is there a need for greater clarity in the Rules on the treatment of the negotiated charge paid by the importing region to the exporting region for the purposes of determining annual aggregate revenue requirement of a TNSP?

It is not considered that the charge should be negotiated, as there is no pressure on TNSPs to do so. The Rules should develop the method that the AER will enforce as to the allocation of costs from one region to another

49. Would it be appropriate to extend the expiry date of clause 3.6.5(a)(5)(ii) from 1 July 2006 to 31 December 2006 to coincide with the conclusion of the Commission's review?

It is important to ensure the Rules are consistent. As the clause is currently not used except between SA and Victoria, to extend the period of operation of the clause for 6 months is not seen as an impost.

Alternatives

The MEU considers there are a number of possible solutions to ensuring economic efficiency for using interconnectors and associated intra-regional assets used for the transfer of power between regions.

However, as it is consumers and generators which benefit from the availability of inter-connection, it is inappropriate to leave the assessment and allocation of costs to TNSPs. TNSPs are primarily interested in receiving their AARR. As they receive this amount as a revenue cap, they have less interest in cost allocation than those paying. As discussed earlier, cost allocation should be carried out independently of the TNSPs, or at least reviewed in detail to ensure it meets the principles detailed in the Rules.

Regional governments should not control the allocation of costs within the NEM. They also have their own agendas and economic efficiency of the NEM might not be ranked as high on their list of goals as other matters.

This then leaves the allocation of inter-regional cost allocation in the NEM to generators and consumers. This is best achieved through the independent approach of the Rules and the AER. The principles of inter-regional cost allocation should be prescribed in the Rules and the AER should have the carriage of ensuring these principles are followed.

There are a number of possibilities for allocation of these costs:

1. The first and most simple would be for there to be no agreements between regions, but that the settlements residues auction proceeds are to be allocated to the exporting region. As each auction is for a transfer in one direction, then if there are both forward and backward flows then the auction proceeds for each would be allocated to the exporting region, and not based on a net flow.

2. The assets used for the bulk of transfers of inter-regional power (ie the backbone of the NEM which would include (say) the 275kV line from Adelaide to Heywood and the 500kV line from Heywood to the Latrobe Valley and so on into Queensland) would be valued separately. The cost of using these specific assets would be determined and allocated on a basis reflecting the total amount of power generated and/or consumed in each region. As there is there is potential for both generators and consumers to pay for use of transmission assets, this calculated cost could be further divided between generators and consumers in proportion to the main allocation of use of system costs.

3. More complex arrangements are possible but when considering the relatively low total value of these specific assets (when compared to the total of all transmission assets) it may be inefficient to attempt to develop a more specific and detailed cost allocation methodology as the return for doing so might not warranted the additional costs of doing so.

50. Do the current, or alternative arrangements provide TNSPs with adequate incentives to invest in assets that facilitate electricity flows between adjacent jurisdictions? If not what improvements could be made?

A TNSP will invest in augmentation if it sees that it will get paid for having the new asset. It requires that the return it gets equals or exceeds the return it might get for investing in a similar risk asset and the certainty of the duration of the return the life of the investment is assured.

Thus, the certainty of the investment is related to the likelihood of the regulator permitting the asset into the regulated asset base, for a period long enough to ensure the return of the capital.

This means that it is the outcome of the Regulatory Test which determines whether the investment will occur.

51. Should the negotiations of inter-regional payments be between TNSPs rather than jurisdictional governments?

As discussed above, neither the TNSP nor the regional government has economic efficiency of the NEM as its core driver. To leave these negotiations to either is inappropriate.

52. Should incentives/penalties be in place in the Rules to ensure that an inter-regional agreement is in place?

As long as a TNSP gets its revenue it has no interest in reaching agreements with another TNSP. To force them to reach agreement for the sake of doing so will not ensure economic efficiency.

It lies within the purview of the Rules and the AER to ensure that appropriate controls are in place to ensure economically efficient allocation of these costs. The MEU has made some suggestions, and adjures the AEMC not to dedicate too much effort into an issue which might not provide sufficient signalling to warrant the input.

53. Should the provisions of clause 3.6.5 be replaced by a modified approach to TUoS pricing more generally?

The MEU has suggested some alternative to the current arrangements which could be readily implemented. As noted above, it is considered that the price signals which might result from a more complex arrangement might not warrant the effort