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27 January 2012

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Dear Mr Pierce

Transmission Frameworks Review First Interim Report

The Australian Energy Regulator (AER) welcomes the opportunity to respond to the AEMC's First Interim Report. Please find attached our submission, which sets out a package of internally consistent proposals encompassing network access, planning and connections.

A key feature of the AER's proposals is a modified version of the Shared Access Congestion Pricing (SACP) mechanism where it is possible to purchase priority access rights for some or all of a generator's capacity. It also involves establishing a competitive market for connections.

I would like to reiterate our support for the work being undertaken by the AEMC as part of this review. We would be happy to discuss any of the issues raised in this submission, or to contribute to the review in other ways in order to develop a transmission framework that promotes the long terms interests of electricity customers. If you have any queries or comments, please contact Jess Hunt on (08) 8213 3441 or Mark Wilson on (08) 8213 3419.

Yours sincerely

W. J. Anderson

Warwick Anderson
Acting Chief Executive Officer

AER Submission to First Interim Report

Transmission Frameworks Review

January 2012

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Summary

The AER welcomes the opportunity to respond to the Transmission Frameworks Review (TFR), and commends the AEMC for developing a broad range of options for consideration. As we said in our submission to the April TFR Directions Paper, the AER considers that the current evidence supports the need for continued reform to the transmission framework. In particular, the AER supports:

- the removal of incentives on generators to bid to the price floor and reduce ramp rates in the presence of congestion (referred to as disorderly bidding)
- enhanced incentives on transmission networks to maximise service capability
- greatly strengthened incentives on new generators to locate efficiently
- protection of transmission service delivery, particularly interconnector capability, when new generation is installed.

In this response the AER discusses the case for reform, and then sets out a package of internally consistent proposals that encompasses network access, planning and connections. The package has the potential to address each of the issues set out above, however, the AER has not attempted to develop the detailed aspects of the proposals at this stage.

A key feature of the suggested approach is a modified version of the Shared Access Congestion Pricing (SACP) mechanism where it is possible to purchase priority access rights for some or all of a generator's capacity. It also involves establishing a competitive market for connections, as occurs in NSW distribution. Under the proposed model it would be possible for a connection applicant to be connected to the transmission network without having to deal with the local TNSP.

The AER considers that its proposal would:

- resolve the problems associated with the current connections regime,
- remove the incentive for disorderly bidding
- enhance investor certainty by creating priority access rights and
- strengthen incentives on new generators to locate efficiently.

The AER has also makes submissions on other issues, including the timing of transmission resets and the harmonisation of the transmission planning regime.

1 Introduction

One of the AER's functions is market monitoring, for instance, we are obliged to prepare a report whenever the spot price of electricity exceeds $5000/MWh.[1] This role means that we are well placed to comment on the market outcomes associated with the current arrangements. As stated in our submission to the April TFR Directions Paper, the AER considers that the current evidence supports the need for continued reform to the transmission framework. In particular, the AER supports:

- the removal of incentives on generators to bid to the price floor and reduce ramp rates in the presence of congestion (referred to as disorderly bidding)
- enhanced incentives on transmission networks to maximise service capability
- greatly strengthened incentives on new generators to locate efficiently
- protection of transmission service delivery, particularly interconnector capability, when new generation is installed.

The AER notes that the range of options considered in the First Interim Report has the potential to address these issues.

In this response the AER discusses the case for reform, and then sets out a package of internally consistent proposals that encompasses network access, planning and connections. Some of the proposals contains new ideas that would require further development. The AER hopes that the AEMC may consult further on the AER's proposal.

[1] National Electricity Rule 3.13.7(d).

2 Case for reform

To assist the AEMC in its examination of congestion in the NEM, the AER has collated the main congestion-related incidents occurring during 2011.[2] Table 2.1 provides a summary of incidents which had a sufficiently destabilising effect on market outcomes to warrant discussion in the AER's market monitoring publications. The AER considers that these incidents provide evidence of ongoing issues associated with the current transmission framework which support further reform, particularly in terms of congestion management.

Table 2.1 Examples of constraints arising during 2011

Settlement date	Region	Event	AER Document
9/11/2011	NSW	High price ($6498) at 3.30 pm.	*Prices above $5000/MWh - 9 November 2011 - NSW*
5/09/2011	QLD	High price ($2117) at 11 am.	Weekly report 6 - 12 November 2011
31/07/2011	SA	Negative prices ($-307) between 8.30 and 9.30 am.	Weekly report 24 - 30 July 2011
31/05/2011	NSW	Negative price ($-147) at 11 am.	Weekly report 29 May - 4 June 2011
30/05/2011	VIC	High price ($1814) at 1.30 pm.	Weekly report 29 May - 4 June 2011
20/03/2011	QLD	High price ($1561) at 2 pm.	Weekly report 20 - 26 March 2011
5/02/2011	NSW	High price ($2150) at 4 pm.	Weekly report 30 January - 5 February 2011
24/01/2011	QLD	High price ($420) and negative price($-318) between 1pm and 2 pm.	Weekly report 23 - 29 January 2011
19/01/2011	QLD	High prices ($2104) between 9.30 am and 2 pm.	Weekly report 16 - 22 January 2011
18/01/2011	QLD	High prices ($3036) between 11 am and 3.30 pm.	Weekly report 16 - 22 January 2011
17/01/2011	QLD	High prices ($2561) at 9.30pm.	Weekly report 16 - 22 January 2011

While the AER supports an evidence-based approach, and recognises the merit of maintaining consistency in market design, we are concerned that the AEMC's current approach to assessing the various options may be too committed to retaining the status quo. In particular, we are concerned that there is a risk that the AEMC approach may overlook inefficiencies associated with the open-access model that are not accurately quantifiable due to the absence of a counter-factual.

Whilst the direct short-term effect of the market outcomes described in Table 2.1 in terms of production inefficiencies may not be particularly significant, medium to longer term dynamic and allocative efficiency effects arise because these market outcomes create unnecessary volatility and risk for market participants and affect price signals.

[2] While we agree that the prevalence of congestion is a relevant consideration, we note that levels of congestion under the current market framework are distorted by bidder behaviour since generators frequently modify their bids to avoid (or create) congestion.

The transmission framework is a core feature of the market structure and any deficiencies in its design have serious flow on consequences throughout the NEM. The AEMC's assessment of an open access regime ought to include the additional costs to generators and retailers associated with uncertain access to the wholesale market. This uncertainty adds to generators' financing costs and contributes to market volatility. For instance:

- The NEM is one of the most volatile commodities market in the world. The risks associated with operating in this market are reflected in increasing retail margins and the dominance of gentailers in the retail sector.

- Some generators have suggested that investors seeking to invest in generation assets under the current open access regime face higher financing costs than investors in jurisdictions with fully firm access. Since generators are unable to avoid the risk that their access to market may be undermined by future connections, they are considered by financiers to be a relatively risky investment. As a result, they find it more difficult to attract finance and must bear the additional costs.

- As well as the effect of higher costs, financing issues have implications for the pattern of investment. The difficulty of persuading financial institutions to invest in generation assets has led to a disproportionate level of investment in (less capital intensive) peaking plant instead of baseload plant. This results in a higher marginal cost of electricity.

The costs associated with these outcomes are partially attributable to the transmission framework and should be reflected in the AEMC's assessment of an open access regime.

The TFR review provides a unique opportunity to consider a broad range of inter-connected issues in a holistic manner. Such wide-ranging reviews occur infrequently. The AER urges the AEMC to take full advantage of this opportunity to fix the problems associated with the current arrangements. The alternative is likely to be the continuation of these shortcomings for a significant period of time.

3 Network access and charging

In this section, we provide comments on the packages put forward in the First Interim Report and then put forward an alternative option which includes, among other things, a new proposal for introducing generator access rights.

3.1 AER views on the packages set out in the First Interim Report

At a high level, the AER's views on the five packages set out in the First Interim Report are:

- **Package 1 - Open access regime.** For reasons set out in Section 2 of this response, the AER does not support the retention of the open access model.

- **Package 2 - Open access with congestion pricing.** The AER supports the introduction of a modified version of the Shared Access Congestion Pricing (SACP) model. It has a number of advantages in terms of removing incentives for disorderly bidding and providing more transparent information about the costs associated with congestion.

  Among other things, this information could be used to refine the incentives on TNSPs to manage congestion efficiently. The AER's market impact parameter (part of the Service Target Performance Incentive Scheme) currently gives equal weight to all congestion incidents that lead to an increase in the cost of dispatch by more than $10/MWh. The AER was obliged to adopt this approach because of the distorting effects of disorderly bidding, which can cause a minor congestion incident to have an extreme effect on prices and dispatch. If more transparent information about the costs associated with congestion becomes available, the AER would be able to refine the market impact parameter to better reflect the costs and hence create more targeted incentives on TNSPs to operate their networks efficiently.

  Package 2 would be relatively simple to implement and would bring immediate benefits. However, Package 2 is insufficient on its own since it fails to address the uncertainty and lack of locational signals associated with an open access model. The AER describes an alternative option which combines features of Package 2 and 4 in section 3.2.

  Finally, the AER supports further consideration of the treatment of interconnectors under the SACP model. In particular, the AEMC should examine further the suggestion set out in Appendix A of the First Interim Report—granting interconnectors an automatic CSC allocation, which would be used to top up the inter-regional settlements residue fund.[3]

- **Package 3 - Generator reliability standards.** The AER supports further consideration of whether generator reliability standards should be applied as part of the transmission framework (and if so how). However, we note that under the current form of Package 3, disorderly bidding would persist unless congestion is built out. It also limits the flexibility of generators to select a level of network access that meets their business needs.

- **Package 4 – Regional optional firm access.** The AER supports the introduction of some form of optional firm access on grounds that it improves locational signals for generators and enhances investor certainty. As expressed in previous submissions, the AER has long standing concerns about the absence of incentives on generators to locate efficiently and the impact that this has on market outcomes. While Package 4 creates benefits from an investor certainty perspective, it carries the risk that if generators elect to remain non-firm, then problems associated with disorderly bidding will persist. Given the

[3] See page 224.

stance of the Northern Generators Group, it appears that this is a particularly significant risk in Queensland and NSW. Section 3.2.1 of this submission discusses how access rights could be allocated among generators. Under the AER's proposal, compensation for access rights are provided via a modified SACP, with the result that the regime would be much easier to implement than Package 4.

- **Package 5 - National locational marginal pricing.** The AER has concerns about the use of periodic auctions to determine capacity charges and the potential implications for investment certainty. Given the nature of the transmission network, it is likely that there would be limited opportunities for market-determined price signals. We would expect most capacity to be sold at the administratively-determined reserve price as has occurred in the UK gas transmission market.

- **Package 6 – International Power- GDF Suez (IPRA) model (provided on 16 January 2012).** The AER supports further consideration of this option. The model is similar to our own in many respects, although we consider that our model has advantages in terms of simplicity and productive efficiency during periods of congestion. In particular, we support further consideration of whether generators should be protected from service degradation caused by the TNSP's investment decisions (as opposed to service degradation that is caused by subsequent generator entry).

The AER considers that a combination of Package 2 (congestion pricing) and Package 4 (optional firm access) is most likely to minimise the total system costs faced by electricity consumers. However, on their own, each of Packages 2 and 4 contain important omissions. To address these concerns, the AER has developed a high level model which combines the beneficial features of Package 2 and Package 4 in an internally consistent manner.

3.2 Priority access model

We propose a modified version of the SACP mechanism where it is possible to obtain priority access rights for some or all of a generator's capacity.

Access rights should be available to new generators that meet a priority access standard which is set out in the National Electricity Rules. While the AER does not, at this stage, have views on the precise form of the priority access standard, our intention is that generators that meet the standard would have a neutral impact on the shared transmission network.[4] Issues relevant to the choice of priority access standard are discussed further in section 3.2.1.

New connecting generators that wish to obtain priority access may need to fund connection works designed to meet the priority access standard (the arrangements for incumbent generators are discussed in section 3.2.1). In return for their investment (in either their plant or in the network) over and above the minimum, priority generators would be entitled to preferential treatment in the event of congestion.

[4] The AER considers that a modified version of the automatic access standard could be appropriate – a connecting generator that wishes to have priority access rights would need to fund investment such that when connected it does not reduce any inter-regional or intra-regional power transfer capability below the level that would apply if the generator were not connected (in a similar way to Schedule 5.2.5.12(a)). The objective of the standard would be to ensure that generators that choose to site their assets in locations that are not efficient from a broader network perspective would need to fund network investment to offset the consequences of their decision if they want to receive priority access rights. An example of a generator that is likely to be affected by this requirement is Kogan Creek – see the AER's response to the TFR Consultation Paper.

We propose that Constraint Support Contracts (CSCs) are allocated in accordance with a hierarchy based on access rights:

- at nodes where one or more generators have obtained priority access rights, priority generators would take precedence in the allocation of CSCs. They would be allocated CSCs in accordance with their priority access rights, with a result similar to the amounts received by firm generators under Package 4.[5] The remaining CSCs would be divided between generators without priority access on a pro rata basis, as per Package 2.

- at nodes where there are no priority generators, the SACP would operate as described in the First Interim Report's Package 2.

Attachment 1 describes the mechanism in more detail.

If there are insufficient CSCs to fully compensate all priority generators, the CSCs would be allocated pro rata on the basis of priority access rights. Accordingly, the model is not fully firm.

While the benefits associated with having priority access might be less than the benefits of having fully firm access, this is appropriate because priority access would involve only incremental additional costs, and potentially no additional costs if a generator chooses to locate at a point on the network which is unconstrained. The charges for priority access rights are discussed below. In addition, there is potential for cost pressures to be reduced through the AER's proposed changes to the connection regime (see section 5).

3.2.1 Charges for priority access rights

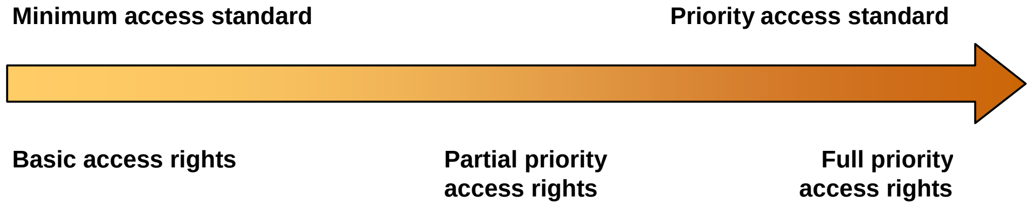
The process for calculating charges for access rights has the potential to be difficult and contentious. However, the AER believes that a regime which attempts, imperfectly, to establish cost reflective prices is likely to achieve more efficient outcomes than a regime which does not attempt to provide price signals.

So far as practicable, we support the use of market mechanisms to set prices for access rights. In particular, connection works could be procured on a contestable basis, with AEMO responsible for specifying the technical attributes of the generator and of the connection works associated with the required level of access. This approach is discussed further in section 5.1.1 of this submission.

The level of investment associated with a connection would vary, depending on whether the connecting generator wished to have basic access, partial priority access or full priority access, as shown in Figure 3.1

5 Priority generators would receive an amount equivalent to the difference between the RRP and the local marginal price (LMP) in respect of each MWh of priority capacity purchased.

Figure 3.1 Relationship between access standards and priority access rights



We note that the definition of the priority access standard is key to determining the nature of this regime. A priority access standard which is set at a "high" level (i.e. where significant additional investment is required to meet it) would result in priority access rights that are rarer, and more valuable. Alternatively, the standard could be set at a level that is relatively easy to meet, with the result that only those generators that do not value firm access, or those generators whose choice of location imposes a detrimental impact on the shared network that is costly to offset, elect to have basic access. In either case locational signals are established, since generators must choose between the costs of investing to meet the standard, or the risk that they will receive a lower allocation of CSCs in the event of congestion.

It would be important to clearly define the relationship between the technical characteristics of the connection and the level of associated access rights. The AER proposes that AEMO consult on, document and publish the detailed technical characteristics associated with meeting a given access standard, and the process it uses to calculate eligibility for priority access rights.[6]

Generators that do not have priority access, or which have only partial priority access, could "upgrade" their level of access subject to funding the network reinforcement required to provide the desired level of access (or modifying their plant). Again, the technical requirements associated with the upgrade would be approved by AEMO and the works would be procured on a contestable basis.

The AER also supports making priority access rights tradeable at a given node. Trading would create signals for efficient retirement of plant and assist with the efficient scaling of assets in locations where new generators are expected to connect to the network. Tradeable access rights could also address first mover issues.

Arrangements for incumbent generators

There is a range of options for the treatment of incumbent generators. For instance:

- **Incumbent generators are given priority access.** Incumbent generators could be allocated priority access rights based on their existing network access. Where network limitations do not permit all the generators in an area to have access rights up to their full capacity, it would be necessary to develop an appropriate methodology to allocate rights.[7] Allocating on a pro-rata basis may be the most appropriate approach, possibly with some refinement for non-scheduled and semi-scheduled generators and peaking plant.

[6] AEMO currently has a shared role with TNSPs in defining the technical standards to be met by new connecting generators. See National Electricity Rule 5.7.3.

[7] Some questions for consideration in relation to how to allocate would include whether generators whose location decisions have had a detrimental impact on network capacity should receive the same treatment as other incumbent generators, whether non-scheduled or semi-scheduled intermittent generation should be treated differently to scheduled generation, and whether peaking plant should be treated different to base-load plant.

- **Incumbent generators are given basic access.** Incumbent generators could be treated as non-firm unless they choose to fund the augmentation works required to upgrade their level of access.

- **Give incumbent generators the opportunity to purchase priority capacity rights in the existing network.** The quantity of access rights available for purchase by incumbent generators would reflect existing network capacity. Charges could be determined either via a one-off capacity auction or on an administrative basis.[8] The AER would prefer an auction since it would help to illuminate the value of capacity rights across the transmission network.

- **A combination of the above.** Incumbent generators could be allocated priority access rights to the existing network based on a fixed proportion of their existing capacity, with the remaining rights allocated via an auction. Requiring generators to purchase at least some access rights has important benefits in terms of price revelation and ensuring that generators value the product. Giving access rights away could result in the rights being undervalued.

In each case, incumbent generators should have the opportunity to trade rights that they do not wish to retain (see above).

Avoiding discrimination between incumbent generators and new entrants is one of the most challenging aspects of any proposal to reform the transmission access regime. However, the problem is essentially a transitional issue and should not become a barrier to reforms that will ultimately deliver more efficient outcomes.

[8] In this case, the revenue accruing to TNSPs should be returned to customers via a negative pass through amount applied to the TNSPs' maximum allowed revenues. Otherwise TNSPs would recover the same costs twice.

4 Planning

This section briefly outlines the AER's preferences in relation to the planning regime, with a particular focus on the proposal to align TNSP regulatory resets.

4.1 Options for incremental reform

The AER considers that there is a case for incremental reform of the planning arrangements. We support further consideration of each of the options for incremental reform discussed in section 11.2 of the First Interim Report. More specifically:

- **National framework for transmission network reliability standards for load.** As set out on previous occasions, the AER supports the conclusions of the AEMC's review of transmission reliability standards.

- **Improving consistency of APRs.** The AER agrees that a uniform format would make it easier to compare APRs. In particular, it would facilitate comparisons between TNSPs for the purposes of economic regulation. Accordingly the AER supports the proposal.

- **Improving transparency when applying the RIT-T.** The AER supports further consideration of the proposal to require TNSPs to estimate economic impacts on market participants and customers that would be affected by a proposed investment in their RIT-T assessments. While we agree that there are benefits in improving transparency, these benefits need to be weighed against the costs of the additional analysis involved and any associated delay in completing RIT-T assessments.

- **Reliability standards for interconnectors.** The AER supports further consideration of this option since we share concerns about lack of incentives on TNSPs to maintain the capability of interconnectors. Indeed, the AER is currently consulting on whether to introduce some form of network capability incentive on TNSPs.[9] The incentive would encourage TNSPs to devote resources to maintaining the capability of their existing network rather than focusing solely on new investments. TNSPs would be rewarded for improving the capability of existing infrastructure, and penalised for allowing network capability to deteriorate.

Given the potentially significant impact of the proposal to align TNSP resets on the AER's activities, we provide more detailed comments on this issue below.

4.1.1 Alignment of TNSP resets

The AER supports a more ordered approach to regulatory resets, and accordingly we support further consideration of the proposal to the align TNSP regulatory resets. As well as the benefits identified by the AEMC in terms of planning, this approach could provide benefits in terms of economic regulation, since reviewing each TNSPs' regulatory proposal simultaneously would promote effective cost benchmarking and consistent regulatory arrangements among TNSPs. These benefits need to be weighed against the potential costs which would include disruption to work flows and business processes, interim regulatory

[9] AER, *Electricity Transmission Service Target Performance Incentive Scheme*, October 2011, pg. 19.

decisions[10], and challenges associated with businesses that use different financial reporting years (for instance, those with owners in Singapore).

From a planning perspective, the potential benefits associated with aligned DNSP resets are not as large as for TNSPs. However, aligned distribution resets would yield benefits in terms of economic regulation, particularly given that DNSP workload tends to be more homogeneous than in transmission. We note that many different approaches could be pursued, for instance, TNSP resets could be aligned and DNSP resets could be reordered but not fully aligned. There may also be scope to consider extending the duration of the regulatory periods.

The AER considers that the benefits associated with aligned resets are unlikely to be realised unless the limitations of the current framework for economic regulation are addressed. For instance, the NER restricts the AER's ability to deviate from the NSPs' revenue proposal. The changes set out in the AER's Rule change proposal[11] would enhance the potential benefits associated with aligned resets and would also make it easier to align the resets. A strengthened role for benchmarking in combination with greater flexibility for the AER to design incentive schemes would reduce the AER's reliance on resource intensive bottom-up expenditure reviews.

In the interests of regulatory stability, we advocate a long lead-in time for the alignment of resets. We suggest that the process of aligning TNSP resets could commence during the round of resets beginning with Powerlink in 2017. During the interim the AER would continue work to develop a strong body of comparable cost data.

The AER has also considered the option of aligning transmission and distribution resets by NEM region. This approach has a number of attractive features. For instance, it would allow the AER to consider whether TNSP and DNSP network development plans are complementary. On balance, however, the AER considers that there are greater benefits associated with aligning resets by sector because of the advantages this approach offers in terms of economic regulation. We note that the current planning arrangements already include mechanisms designed to promote consistent network development. Further, the introduction of SA-style network planning arrangements (see below) would promote consistency in demand forecasts without the need to align resets by NEM region.

4.2 Options for more significant reform

In relation to the other options for more significant reform put forward in the First Interim Report, the AER considers that:

- **Option 1 - Enhanced coordination of APRs and NTNDP.** While we do not oppose this option, we believe that it is likely to be of limited consequence in practice.
- **Option 2 - Harmonised regime based on current South Australian arrangements.** We support this option. At present, demand forecasts are a contentious element of the regulatory reset process, since network businesses have an incentive to over-forecast

[10] For instance, Ofgem's realignment of its resets was given effect via a series of short term "rollover" reviews that were significantly less detailed than a full review. Where appropriate, Ofgem simply extrapolated parameters from the preceding regulatory period.

[11] AER, *Rule change proposal – Economic Regulation of Transmission and Distribution Network Service Providers*, September 2011.

peak demand in order to maximise their allowed revenues. Accordingly, the AER considers that transferring this role to AEMO would provide benefits in terms of economic regulation. This approach would also complement the AER's proposed contestable connections model (see next section), since a harmonised regime would make it easier for firms to compete for connections work in multiple jurisdictions.

- **Option 3 – Single NEM wide transmission planner-procurer.** The AER believes that this approach should be considered further, but may result in an overly centralised transmission model. We are also concerned about the potential lack of checks and balances, since AEMO's planner-procurer activities in Victoria are not exposed to the regulatory reset process. That said, we support an expansion of AEMO's role in relation to connections (see section 5.1.1).

- **Option 4 - Joint-venture planning body established by TNSPs.** Given the divergent interests of TNSPs, it may be very difficult to make this option work. This approach is also likely to give rise to significant duplication of resources.

5 Connections

The AER believes that the current arrangements for obtaining a connection to the transmission network are flawed. We note that network connections are a recurring problem in many jurisdictions around the world. Given that these issues arise as a result of the monopoly position of the incumbent network provider, we advocate the introduction of competition to resolve the problems arising in the connections market.

5.1 AER views on options set out in the First Interim Report

Of the options put forward in Chapter 13 of the First Interim Report, the AER supports Proposal 2 (enhancements to the negotiating framework). This proposal would strengthen the bargaining position of connection applicants by improving their access to information.

Proposal 1 (enhancements to the dispute resolution framework) is unlikely to be effective on its own, since it fails to address one of the underlying problems with the current arrangements—namely, that connection applicants are unwilling to jeopardise their future relationship with the TNSP by entering into dispute resolution. However, if the AEMC decides that Proposal 1 is worthwhile, then the AER prefers the appointment of an independent panel to an approach where the AER resolves disputes. We consider that there is potential for a dispute resolution role to conflict with our monitoring and enforcement role.

The AER does not support Proposal 3, since it would entrench the monopoly position of TNSPs in the provision of connections.

The AER suggests the AEMC consider a further option for improving the connections arrangements. We suggest a model where connections works (including network extensions and augmentations) are contestable. If this type of model was adopted, the proposals contemplated in Chapter 13 would become unnecessary.

5.1.1 Contestable connections model

The AER suggest that the AEMC considers a model whereby connection applicants procure their transmission connection from an Accredited Service Provider (ASP) on a competitive basis, subject to oversight by an independent scheme administrator. This model is broadly based on the Accredited Service Providers Scheme that applies in NSW electricity distribution. This scheme is described in the NSW Better Regulation Office's Review of NSW electricity network contestable services which concluded that the scheme should be retained and expanded.[12]

The AER proposes that in transmission, the scheme administrator could be AEMO. AEMO is well placed to fulfil the relevant functions, particularly given its roles in approving generator technical standards across the NEM, and in planning and procuring the Victorian transmission network. Accordingly, the AER proposes that the ASP scheme would be entirely administered by AEMO, rather than allowing some functions to reside with the network businesses as originally occurred in the NSW scheme.

[12] See http://www.betterregulation.nsw.gov.au/targeted_reviews/review_of_nsw_electricity_network_contestable_services

At a high level, the scheme administrator would have responsibility for:

- **Accreditation.** This would involve providing accreditation at both a corporate and individual level, to ensure that the ASPs have appropriate skills and training and that they meet the relevant prudential requirements;

- **Certification.** The scheme administrator would examine and approve proposed connection designs and ensuring that relevant safety and technical standards are complied with. This would also involve forming a view on the technical attributes of the connection works associated with a given level of priority access rights;

- **Inspection.** The scheme administrator would also inspect and approve new connections prior to commissioning.

It would be necessary for the scheme administrator to reach an agreement with each TNSP concerning the technical and safety standards and functional specifications to apply to the relevant network. However, the TNSP would not be involved in applying those standards in relation to an individual connection application. TNSPs that wish to provide connection related services would need to compete with other ASPs on a competitively neutral basis.[13] TNSP connections subsidiaries would have the opportunity to compete for projects outside their own region.

As with the NSW scheme, it is likely that there would need to be different levels of accreditation, depending on the types of work undertaken. The AER considers that appropriately accredited ASPs should have the opportunity to undertake network augmentations as well as network extensions and connections works. It is common practice for TNSPs to contract out the construction of major projects—indeed some TNSPs already outsource all construction, supported by detailed, transparent functional specifications. The AER envisages that such functional specifications could also be utilised by ASPs.

5.2 Providing and accessing extensions to the shared network

In this section the AER sets out its response to the matters discussed in Chapter 14 of the First Interim Report (providing and accessing extensions to the shared network). As set out above, the AER considers that the construction of both extension assets and connection-related augmentations should be contestable.

TNSPs should then take on responsibility for operation and maintenance of network extensions and any generator-funded augmentations, with the effect that third parties would be able to access network extensions. This approach promotes efficiency in the construction of network extensions, supports efficient use of the network and promotes competition between generators.

To incorporate these features into the AER's proposed model, it would be necessary to revise the National Electricity Rules to require generator-funded extensions and augmentations to the shared network to be transferred to the TNSP following inspection and approval by AEMO. The TNSP would become the owner of the asset and would be responsible for operation and maintenance. TNSPs would receive an operating expenditure allowance in respect of such assets, but they would not enter the regulatory asset base.

[13] Competitive neutrality would include ensuring that the TNSP's connections business is arm's length from their prescribed transmission business.

To protect the TNSPs against the operating risk associated with assets that they have not designed or built, TNSPs would be eligible for a cost pass through event if it could be shown that they were obliged to incur additional costs as a result of a faulty or inappropriately designed gifted asset. TNSPs would also be protected by NER and ASP Scheme requirements on connectees, ASPs and AEMO to meet network safety and reliability standards.

For this framework to take effect, it would be necessary to resolve a number of issues. In particular, it would be necessary to resolve:

- the tax issue associated with gifted assets[14], and
- how generators could retain the tradeable priority access rights associated with assets they have built if ownership is transferred to the TNSP.

While this approach would require significant further development, the AER believes that its potential net benefits are sufficiently large that the model merits further consideration.

[14] AEMC, *Transmission Frameworks Review First Interim Report*, November 2011, pg 166.

Attachment 1 Priority access model

The AER has attempted to develop a model which combines Option 2 and Option 4 in an internally consistent manner. We propose a modified version of the SACP mechanism where it is possible to purchase priority access rights for some or all of a generator's capacity.

Consistent with the SACP, during periods of congestion, generators that are behind the constraint would receive a locally determined price rather than the regional reference price (RRP). However, rather than allocating congestion support contracts (CSCs) among generators on a pro rata basis, we propose that there is a hierarchy based on priority access rights. At nodes where one or more generators have priority access, CSCs would be allocated in accordance with the following two-stage process:

- distribute CSCs to priority generators so that they receive an amount equivalent to the difference between the RRP and the local marginal price (LMP) in respect of each MWh of priority capacity purchased,[15]
- any remaining CSCs are divided between generators that do not have priority access on a pro rata basis according to their capacity and the extent to which they contribute to the constraint, as per Package 2.

The outcomes for a priority generator under this model are broadly equivalent to what they would be entitled to under Package 4. At nodes where there are no priority generators, the SACP would operate as described in the First Interim Report's Package 2.

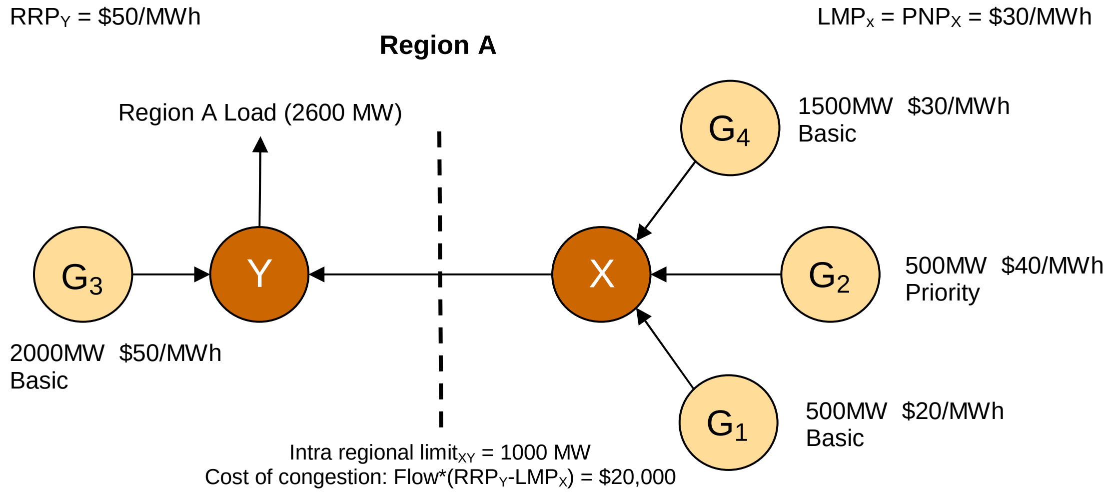
If a generator opted to have partial priority access:

- during stage 1 of the CSC allocation process they would be entitled to CSCs reflecting their priority access rights,
- during stage 2 of the CSC allocation process they would be entitled to CSCs reflecting the proportion of their capacity which is subject to basic access rights.

Figures 1, 2 and 3 illustrate how the mechanism would work in a variety of circumstances, including when a generator has partial priority access and when all generators have priority access. The parameters are based on those used in Figure A.3 of the First Interim Report and the assumptions that apply in the First Interim Report also apply here.

[15] In the event that there are insufficient CSCs to fully cover all priority capacity rights, CSCs would be divided between priority generators on a pro rata basis according to the quantity of priority access rights purchased.

Figure A1 - Example of outcomes under priority access regime



In this example, CSCs are allocated as follows:

Total CSCs = Flow(RRP_Y-LMP_X) = 1000*(50-30) = $20,000*

1. Distribute CSCs to priority generators. In this case,

   - G_2 has 500 MW of capacity, for which it receives 500*(50-30) = $10,000.

2. Allocate the rest of the CSCs between generators with basic access on a pro rata basis. In this case:

   - G_1 receives $10,000/(1500+500)*500 = $2,500
   - G_4 receives $10,000/(1500+500)*1500 = $7,500.

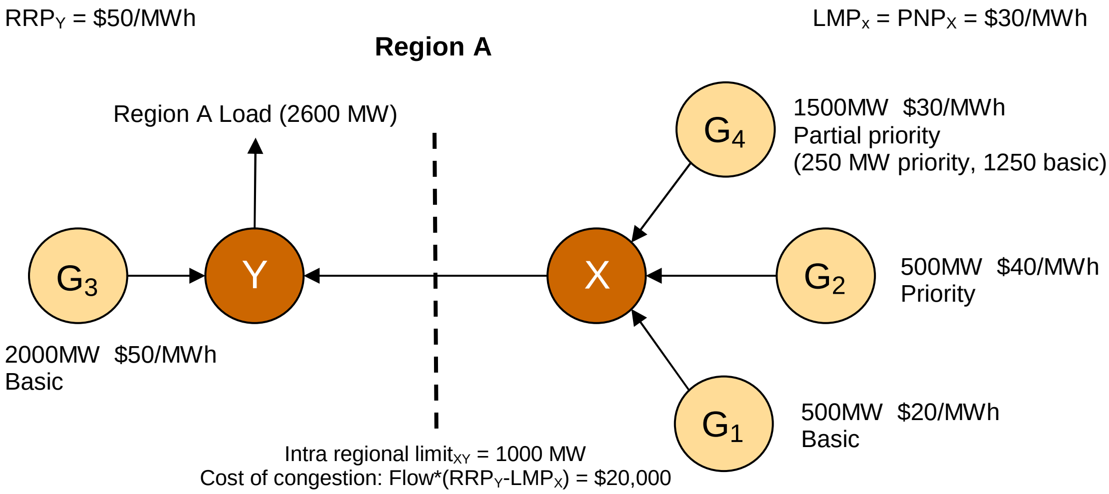
Dispatch outcomes, resource costs and profits under the priority access model are shown in Table 1 below.

Table 1 – Dispatch outcomes, resource costs and profits

Gen.	Capacity (MW)	Offer price ($/MWh)	Access rights (MW)	Dispatch (MW)	Resource costs ($)	Revenue from dispatch	CSC ($)	Profit
G_1	500	20	0	500	10,000	15,000	2,500	7,500
G_2	500	40	500	0	0	0	10,000	10,000
G_3	2000	50	0	1600	80,000	80,000		
G_4	1500	30	0	500	15,000	15,000	7,500	7,500
Total			**500**		**105,000**	**110,000**	**20,000**	**25,000**

Figure 2 and Table 2 provide an example of how the priority access model would work in the case where a generator is partially firm.

Figure 2 - Example of outcomes when G4 has partial priority access



In this example, CSCs are allocated as follows:

Total CSCs = Flow(RRP$_Y$-LMP$_X$) = 1000*(50-30) = $20,000*

1. Distribute CSCs to priority generators. In this case,

   - G_4 has 250 MW of priority capacity, for which it receives 250*(50-30) = $5000
   - G_2 has 500 MW of priority capacity, for which it receives 500*(50-30) = $10,000.

   After these CSCs have been allocated, there are $20,000 - $15,000 = $5,000 worth of CSCs left.

2. Allocate the rest of the CSCs between generators without priority access on a pro rata basis. In this case:

   a. G_1 receives $5000/(1250+500)*500 = $1429

   b. G_4 receives $5000/(1250+500)*1250 = $3571.

The results associated with this example are set out in Table 2.

Table 2 – Dispatch outcomes, resource costs and profits

Gen.	Capacity (MW)	Offer price ($/MWh)	Access rights (MW)	Dispatch (MW)	Resource costs ($)	Revenue from dispatch	CSC ($)	Profit
G_1	500	20	0	500	10,000	15,000	1,429	6,429
G_2	500	40	500	0	0	0	10,000	10,000
G_3	2000	50	0	1600	80,000	80,000	0	0
G_4	1500	30	250	500	15,000	15,000	5,000 + 3,571	8,571
Total			**500**		**105,000**	**110,000**	**20,000**	**25,000**

Finally, if there are insufficient CSCs to fully compensate all priority generators, CSCs would be allocated pro rata on the basis of the quantity of priority access rights. Accordingly, this model is not fully firm. Given that generators must invest in physical capacity in order to receive priority access rights, congestion is less likely to arise at points on the network which has mostly priority generators. Accordingly a shortage of CSCs among priority generators is likely to arise relatively infrequently. However it may arise outside of normal operating conditions, such as in the event of a transmission failure.

Figure 3 provides an example of an outcome that could arise if there were insufficient CSCs to fully compensate priority generators. To show this, we have assumed that all generators at node X have priority access.

Figure 3 - Example of outcomes under priority access when all constrained generators have priority access

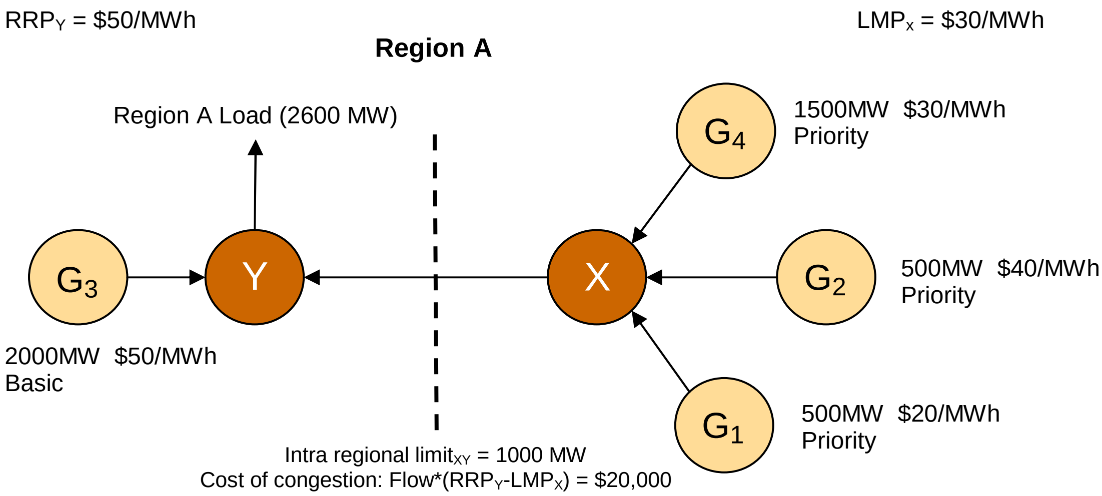


Table 3 – Dispatch outcomes, resource costs and profits

Gen.	Capacity (MW)	Offer price ($/MWh)	Access rights (MW)	Dispatch (MW)	Resource costs ($)	Revenue from dispatch	CSC ($)	Profit
G_1	500	20	500	500	10,000	15,000	4,000	9,000
G_2	500	40	500	0	0	0	4,000	4,000
G_3	2000	50	0	1600	80,000	80,000	0	0
G_4	1500	30	1500	500	15,000	15,000	12,000	12,000
Total			**500**		**105,000**	**110,000**	**20,000**	**25,000**