# 20 Merchant interconnectors

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| Key points |
| * In the National Electricity Market (NEM), merchant interconnectors are distinguishable from regulated interconnectors in that their providers: * earn revenue by trading on the spot market by purchasing electricity in a lower priced region and selling it to a higher priced region, or by selling the rights to revenue traded across the interconnector * are not required to meet the Regulatory Investment Test for Transmission. * At the commencement of the NEM, it was expected that merchant interconnectors would play an important role. This expectation has not been realised. * There is only one merchant interconnector — Basslink (between Tasmania and Victoria). However, it is arguably not a genuine merchant interconnector given its commercial relationship with the generator, Hydro Tasmania. * Two previous merchant interconnectors, Murraylink (between South Australia and Victoria) and Directlink (now called Terranora) (between New South Wales and Queensland) converted to regulated status soon after commencing operations. * There are no new merchant interconnector proposals. * It is unlikely that the current limited role of merchant interconnectors will expand. * Regional price differences are too small to sustain the large investments involved, or to attract new entry. Furthermore, the added capacity of any new merchant (or regulated) interconnector would further diminish inter-regional price differences and, thus, revenues. * The application of the regulatory test to regulated interconnector proposals in the early years of the NEM may have had lasting impacts on the confidence of merchant investors. * International experience suggests that the success of the merchant model depends on transmission rights and nodal pricing, which would require fundamental design changes in the NEM. * There appear to be no large regulatory biases against merchant interconnectors within the NEM. However, compared with generators, there are two minor issues. * Providers of merchant interconnectors cannot receive revenue from the Australian Energy Market Operator for frequency control ancillary services. * There is a lack of clarity around the minimum floor price that applies to merchant interconnectors. * Another approach to interconnector investment is for generators, loads and other parties to propose and finance projects from which they benefit. Because of free-rider and coordination problems, this beneficiary pays approach is likely to be limited to investments with few and identifiable beneficiaries (for example, Basslink). * Both merchant and beneficiary pays approaches to interconnector investment should be capable of being accommodated within a national planner model for transmission. |
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Previous chapters (chapters 17–19) have focused on various aspects about regulated interconnectors in the National Electricity Market (NEM).

An alternative to regulated interconnectors in the NEM is unregulated or merchant interconnectors. These are provided by ‘market network service providers’ (MNSPs) and are distinguishable in that they:

* earn their revenue by trading on the wholesale spot market by purchasing electricity in a lower priced region and selling it to a higher priced region, or by selling the rights to the revenue earned across their interconnector
* are not required to meet the regulatory investment test for transmission (RIT-T).

This chapter explores:

* the current role of merchant interconnectors in the NEM and whether that is likely to expand
* whether there are regulatory biases within the NEM against merchant interconnectors
* the scope for a beneficiary pays approach to interconnector investment.

## 20.1 The role of merchant interconnectors in the National Electricity Market

Within the NEM, there is only one merchant interconnector — Basslink which connects Victoria and Tasmania and which began operations in 2006 (box 20.1). Basslink assigned its rights to inter-regional revenues to the Tasmanian generator, Hydro Tasmania, for 25 years under the Basslink Services Agreement. Two other merchant interconnectors — Directlink (now called Terranora) and Murraylink — began operations in 2000 and 2002, respectively, and subsequently converted to become regulated interconnectors.

Like regulated interconnectors, merchant interconnectors can enhance competition within the NEM. In particular, they can:

* act as a competitor to regulated interconnectors as well as to generators in the linked regions
* facilitate interstate trade in electricity
* fill investment niches that have been overlooked by providers of regulated interconnectors (‘transmission network service providers’ or TNSPs).

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| Box 20.1 Merchant interconnectors in the National Electricity Market |
| Basslink (connecting Tasmania and Victoria) is currently the only merchant interconnector operating in the NEM. It is a high voltage direct current (DC) submarine cable link of 370 km length, connecting the Loy Yang Power Station in Victoria and the George Town substation in northern Tasmania. It has a capacity of 500 MW. Basslink was constructed by National Grid Australia between 2003 and 2005 in response to expressions of interest sought by the Tasmanian Government in the late 1990s. It began operations in 2006. Under the Basslink Services Agreement (which has a 25‑year term), Basslink’s entitlement to inter-regional revenues was assigned to the Tasmanian generator, Hydro Tasmania, in exchange for a facility fee and performance-related payments. Basslink is owned by CitySpring Infrastructure Trust, which is registered with the Monetary Authority of Singapore.  Two other merchant interconnectors previously operated in the NEM, but subsequently converted to become regulated network services.  Directlink (Terranora) (connecting New South Wales and Queensland) is a high voltage DC line of 180 MW capacity that extends 59 km between Mullumbimby and Bungalora in New South Wales, with two AC/DC (alternating current/direct current) converter stations and a single 110kV AC underground transmission link of about 4 km running from Bungalora to Terranora in northern New South Wales, where it interconnects with the Queensland power grid. It was developed as a joint venture of NorthPower, TransEnergie Australia, and Fonds de solidarite FTQ starting in 1999 and began operations in 2000. It converted to a regulated network service in 2006.  Murraylink (connecting South Australia and Victoria) is a high voltage DC link of 220 MW capacity, which extends 180 km from Red Cliffs in Victoria to Berri in South Australia. It was constructed by Trans Energie Australia. It began operations in 2002. It converted to a regulated network service in 2003.  APA Group now operates both Directlink (Terranora) and Murraylink. |
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However, some participants had concerns about merchant investment in transmission (including in interconnectors) or considered that it currently had a very limited role in the NEM. Their arguments included the following:

* It is more efficient to rely on a coordinated approach to investment in transmission than on decentralised market-based approaches. For example, the Australian Energy Market Commission (AEMC) said that greater coordination of inter- and intra-regional planning was desirable:

Therefore, although interconnections between regions provided by regulated TNSPs might tend to ‘crowd out’ merchant investment, relying on a solely merchant approach is unlikely to be practical or efficient. (sub. 16, p. 8).

* There are limited commercial opportunities for viable merchant interconnectors. The significant regional price differentials that underpinned the initial three merchant interconnectors have not been sustained between those regions and have not been evident between other regions. Indeed, inter-regional price differences are currently insufficient between all regions to generate enough revenue for a potential merchant interconnector to cover the costs associated with their capital investment. (This issue is considered in further detail later in this section.)
* Merchant interconnectors have an incentive to limit the amount of electricity they transport in order to keep regional price differentials high. For example, the Major Energy Users said:

The problem with Directlink, and other so-called ‘market network service providers’, in contrast to normal regulated interconnectors, is that they must seek to maintain a certain differential between regional pool prices in order to gain revenue to cover their annual costs — of the order of $10/MWh based on typical costs of HVDC [high voltage direct current] systems of the size used in Directlink. In this respect, they have motivations more like those of generators to keep a high pool price in the receiving system. … (sub. 11, p. 46)

This section discusses the economic basis for, and concerns about merchant interconnectors, the regulatory arrangements within the NEM that allow their operation and the scope for the role of merchant interconnectors in the NEM to expand.

### The economic debate

The merchant model of transmission investment has been the subject of debate amongst economists since it was first described in the early 1990s.[[1]](#footnote-1)

Proponents of the merchant model (initially Hogan 1992 and, more recently, Littlechild 2004, 2011a) argue the following. In return for investment in additional transmission capacity, merchant investors receive property rights that allow them to collect congestion rents equal to the difference in nodal energy prices associated with the incremental point-to-point transmission capacity their investments create. The value of these rights to receive congestion rents is represented by the revenues merchant investors receive to cover the capital and operating costs of their investments and provides the financial incentives that guide ‘market-based’ transmission investment. Investment is then optimal. This challenges the previously held assumption that transmission networks are ‘natural monopolies’ that must be regulated.

However, in their seminal paper, Joskow and Tirole (2005) argued that the conditions required for merchant investment in transmission to be optimal — namely that there is competition, free entry and decentralised property-rights based institutions, and market-based pricing for transmission — are not likely to be met in practice. Relevant considerations here include market power of generators, lumpiness of investment, and strategic behaviour and problems with coordination with other investors (or beneficiaries). These market failures mean that the level of capacity installed by merchant investors is likely to be inefficient. Although Joskow and Tirole admitted that the alternative model of the ‘regulated transco’ has various inefficiencies in practice, they considered it was unlikely that policy makers could rely primarily on the merchant model for an efficient level of transmission investment. In another paper, Joskow (2005b, p. 46) argued that merchant transmission might be a complement but not a substitute for regulated transmission, was likely to make only a very small contribution and efforts to debate its role had been a ‘distraction’.

Several other economists have similarly contended that the role of merchant transmission is likely to be limited. For example:

* Brunekreeft (2005) argued that merchant transmission would be more viable in the United States with nodal pricing and financial transmission rights, but in markets with regional or zonal pricing, merchant transmission would be limited to interconnectors between adjacent regions or zones.
* Rious (2006) argued that merchant transmission would be efficient where economies of scale in transmission were small relative to the size of the market, where DC transmission had a cost advantage over AC transmission, and where differential prices could be maintained.

Littlechild (2011a) attempted to address Joskow and Tirole’s arguments by applying a ‘comparative institutions’ approach to comparing merchant and regulated transmission. He sought to identify what have been the main market failures and regulatory failures, as predicted in theory and in practice in Australia and in Argentina (with its ‘beneficiary pays’ approach). He found that merchant transmission had not exhibited market failures and that regulated transmission exhibited regulatory failures. Lack of coordination (between transmission users and investors) had been a challenge with both approaches. He concluded that regulatory frameworks should be improved to remove barriers to merchant transmission and to facilitate coordination between transmission users and investors.

What is clear is that there is no consensus among economists on the role of merchant transmission investment in electricity markets. As Littlechild said:

There seems to be common ground on the likely need for more transmission investment and the possibility that some form of merchant investment could play a role somewhere. However, there is apparently little agreement among economists as to whether this could or should be a relatively small or large role, and what kinds of policies are best suited to delivering this. (2011a, pp. 2–3)

### Safe harbour provisions

When the NEM commenced in November 1998, the then National Electricity Code Administrator (NECA) acknowledged that there would be difficulties in applying a market-based approach in relation to ‘electricity transport’, which was why the initial National Electricity Code (‘the Code’) focused on network services as ‘regulated’ services:

… it was recognised that serious technical impediments existed to moving to a competitive market in electricity transport. For example, the strong operational interdependencies that arise in a free-flowing AC meshed network make it difficult to apply a market based approach. Therefore, apart from a few exceptions, the Code treats network services as prescribed services … to be provided by regulated monopoly businesses. (NECA 1998, p. 1).

However, the Code envisaged that merchant investors would have a role in relation to interconnectors, but that appropriate ‘safeguards’ would need to be developed by NECA:

The Code envisages that under some circumstances it may be feasible to adopt a competitive approach to inter-regional transport. Such a concept is potentially attractive in that it would avoid the regulatory problems and costs associated with centrally managed augmentation, however, there would need to be adequate safeguards to promote efficient and equitable outcomes. The Code is silent on what those safeguards would be, specifying that the market participation rules for non-regulated interconnectors will be established by NECA through the Code change process. (NECA 1998, p. 1)

These safeguards, described as ‘safe harbour provisions’ for the participation of merchant interconnectors in the NEM (box 20.2), were developed by NECA in 1999 and later reflected in the Code by amendments authorised by the Australian Competition and Consumer Commission (ACCC) in 2001.

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| Box 20.2 Safe harbour provisions |
| In July 1999, as part of its broader transmission and distribution pricing review, the NECA) developed an initial framework — described as ‘safe harbour provisions’ — to enable the market participation of non-regulated (entrepreneurial) interconnectors.  NECA subsequently applied to the ACCC in July and August 1999 to authorise proposed amendments to the Code (and to the NEM access code), which reflected the initial framework.  In its authorisation of the proposed amendments in September 2001, the ACCC set out the safe harbour provisions for merchant interconnectors — called ‘market network service providers’ (MNSPs) as follows:   * The interconnector must comprise a single two-terminal element of at least 30 MW capacity that directly connects networks in different price regions. * The interconnector must be scheduled[[2]](#footnote-2) and subject to analogous rights and obligations to those applicable to scheduled generators and loads. * The MNSP is entitled to revenue from buying and selling energy in two regions and from providing ancillary services. * Flow through the interconnector must be independently controllable if the interconnector forms part of any network loop. * The MNSP must bear the full cost of dedicated connection assets plus other network charges and rebates necessary for efficient investment and utilisation signals. * The MNSP must enter into a connection agreement with the interconnected network in each region. * The MNSP must pay for services to support the operation of the interconnector as well as compensate for any adverse impact on other parts of the network. * The powers of the then National Electricity Market Management Company (now AEMO) to direct the MNSP will be the same as its powers to direct other scheduled plant and the MNSP will be entitled to similar compensation. * Some or all of the MNSP capacity may be used for a reserve trader contract. * The MNSP can apply to convert to regulated status at any time. * The MNSP must submit a code consistent access undertaking to the ACCC.   Although there have been regulatory changes since the ACCC’s authorisation of 2001, by and large, these safe harbour provisions continue to be reflected in the current National Electricity Rules. |
| *Sources*: ACCC (2001); NECA (1998; 1999). |

Many of the safe harbour provisions continue to survive in the current National Electricity Rules (the ‘Rules’). For example:

* Clause 2.5.2 relating to the classification of a ‘market network service’ — which covers merchant interconnectors — includes the following provisions:
* The market network service is to be provided by network elements that comprise a two terminal link and do not provide a regulated transmission and distribution service (for example, a service subject to a revenue determination by the Australian Energy Regulator (AER).
* The MNSP must be registered to operate in the NEM and, thus, must satisfy the prudential, technical and other requirements.
* The connection points of the relevant two-terminal link are assigned to different regional reference nodes.
* The relevant two-terminal link through which the market network service is provided, does not form part of a network loop or is an independently controllable two-terminal link, and has a registered power transfer capability of greater than 30 MW.[[3]](#footnote-3)
* The market network service may be converted by the AER into a regulated transmission or distribution service.
* Clause 3.8.6A (g) and (h) sets out the formulaic basis for how MNSPs earn revenue from trading on inter-regional price differences in the NEM (box 20.3).

Since the introduction of the safe harbour provisions in 2001, there have been two key developments concerning merchant interconnectors.

The first was the events surrounding the application of the then regulatory test to early proposals for a regulated interconnector between New South Wales and South Australia — the SANI proposal in 1997, which was amended to the SNI proposal in 1998. These included court action by the owners of Murraylink — concerned about the impacts of the SNI proposal on their merchant interconnector — that ended in an appeal to the Victorian Supreme Court. Murraylink converted to a regulated service during the court action and lost its appeal in the Victorian Supreme Court in July 2003. The SNI proposal did not eventuate.

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| Box 20.3 **How do merchant interconnectors earn revenue?** |
| Clause 3.8.6A (g) of the National Electricity Rules sets out a formula for the net revenue that a market network service provider can expect to receive for energy delivered between regions A and B:  Net revenue = PB FB – PA FA  Where  PA and PB are the prices at the scheduled network service’s connection points A and B, which are assumed not to change as a result of the incremental transfer.  FA and FB are the energy transfers scheduled by central dispatch for receipt by the scheduled network service at connection point A and delivery at connection point B respectively.  FA and FB are deemed to be related by the loss versus flow relationship published by AEMO.  Clause 3.8.6A (h) provides that the price at a connection point is related to the regional reference node price and loss factors:  The price at a connection point will be deemed to be related as follows to the price at the regional reference node to which that connection point is assigned.  P = RP LF  Where  P is the price at the connection point  RP is the price at the appropriate regional reference node.  LF, where the scheduled network service’s connection point is a transmission network connection point, is the relevant intra-regional loss factor at that connection point, or where the scheduled network service’s connection point is a distribution network connection point, is the product of the distribution loss factor at that connection multiplied by the relevant intra-regional loss factor at the transmission network connection point to which it is assigned.  To give an example, if the spot price in region A is $25/MWh and in region B is $35/MWh, the flow from region A to region B is 400 MW, and losses are zero, then the inter-regional residues that accrue and hence the revenue that a MNSP can earn is:  ($35/MWh - $25/MWh) X 400 MW = $4000/h |
| *Source:* National Electricity Rules. |
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The second development was that, in a 2003 report to Council of Australian Governments on reform of energy markets, the Ministerial Council of Energy (MCE) signalled a policy shift in relation to merchant interconnectors:

The MCE believes that the current arrangements for the coexistence of regulated and market provision of transmission have not resulted in optimal outcomes, and supports removal of biases towards unregulated investment. The MCE will develop code changes and establish a level playing field between regulated and market transmission for implementation in July 2004. The code changes would recognise and protect the rights of existing investors in market transmission services. (MCE 2003a, p. 11)

These regulatory changes appeared to have been given effect in the National Electricity Rules in 2006 in relation to the determination of the opening regulatory asset base of former market network services[[4]](#footnote-4) (AEMC 2006b).

### Is their scope for the role of merchant interconnectors to expand?

Despite the introduction of the safe harbour provisions, it is apparent that early expectations about the role of merchant interconnectors in the NEM have not been realised.

* As noted, there is currently only one merchant interconnector in the NEM — Basslink (between Tasmania and Victoria). Moreover, it is arguable whether Basslink is a genuine merchant interconnector as it is shielded from the commercial risks associated with earning inter-regional revenues by receiving a flat fee from Hydro Tasmania. To the owners of Basslink, it is akin to a regulated interconnector. Hydro Tasmania, as a generator, obtains a commercial benefit when it exports power by way of Basslink, over and above the normal merchant interconnector inter-regional revenues that would otherwise be available to it.
* The other two previous merchant interconnectors in the NEM — Murraylink and Directlink (Terranora) — converted to regulated transmission services within six years of commencing operations. Murraylink applied for conversion one week after commencing operations.
* There have been no new merchant interconnector proposals since Basslink began operations in 2006, and none is expected.

This is in contrast to the experiences of electricity markets in the European Union and in the United States, where the regulators have liberalised their regimes to allow merchant investors to operate (appendix E). A number of merchant transmission projects have developed in response to these actions.[[5]](#footnote-5)

In Australia, however, even with a more liberal regulatory regime, several factors suggest that the current role of merchant interconnectors in the NEM is unlikely to expand.

First, the three merchant interconnectors initially entered the NEM when inter-regional price differentials were over $100/MWh (shaded price differentials in table 20.1). Differentials of this magnitude have not been evident since, and are currently between $0.60/MWh and $5.30/MWh, which is likely to have deterred entry of new merchant interconnectors. Indeed, the (Tasmanian) Electricity Supply Industry Expert Panel suggested that price differentials have not been large enough for the existing merchant interconnector to earn sufficient revenue from this source, to cover its costs.

The direct arbitrage revenue opportunities made available to Hydro Tasmania by Basslink have not, on their own, generated sufficient revenue to cover the overall cost of Basslink to Hydro Tasmania in any year since the link commenced commercial operation, although the business case was not predicated on them doing so. (2012a, p. 54)

The AEMC said:

To date, our work, and stakeholder views, on the [transmission frameworks] review have not suggested that attempting to promote a greater level of unregulated investment in interconnectors would be an appropriate course of action. In order for such merchant interconnectors to be economic, large price differences would be required between regions, and these would need to be maintained even after the interconnector was operational (as the interconnector would be remunerated through the difference in regional prices). (sub. 16, p. 8)

There are risks to the owners of a merchant interconnector that the extra capacity added by any new interconnector would further diminish inter-regional price differences and, thus, revenues.

Second, events surrounding the proposals for regulated interconnectors SANI/SNI between 1997 and 2003, including the resulting court action by Murraylink, may have had lasting adverse effects on the confidence of investors regarding the potential to make commercial returns from merchant interconnectors vis a vis regulated interconnectors.

Table 20.1 Regional differences in average annual (nominal) pricesa

$/MWh

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Year | NSW–Qld | NSW–SA | NSW–Snowyb | NSW–Vic | Vic–Snowyb | Vic–Tasc | Vic–SA |
| 1998-99 | 18.52 | 122.89 | 0.79 | 3.20 | 3.99 |  | 119.69 |
| 1999-00 | 15.84 | 31.00 | 0.31 | 1.92 | 1.61 |  | 32.92 |
| 2000-01 | 3.64 | 18.7 | 0.63 | 6.88 | 7.51 |  | 11.82 |
| 2001-02 | 0.58 | 3.15 | 3.17 | 3.79 | 0.62 |  | 0.64 |
| 2002-03 | 4.88 | 2.80 | 3.08 | 5.35 | 2.27 |  | 2.55 |
| 2003-04 | 4.19 | 2.49 | 1.57 | 6.99 | 5.42 |  | 9.48 |
| 2004-05 | 10.37 | 3.26 | 5.28 | 11.71 | 6.43 | 162.76 | 8.45 |
| 2005-06 | 9.12 | 0.52 | 6.15 | 4.77 | 1.38 | 24.29 | 5.29 |
| 2006-07 | 6.58 | 7.11 | 3.53 | 3.92 | 0.39 | 5.24 | 3.19 |
| 2007-08 | 10.68 | 31.84 | 3.83 | 5.13 | 1.30 | 7.89 | 26.71 |
| 2008-09 | 4.85 | 12.13 |  | 2.97 |  | 16.66 | 9.16 |
| 2009-10 | 10.89 | 11.12 |  | 7.91 |  | 6.91 | 19.03 |
| 2010-11 | 5.77 | 4.16 |  | 9.65 |  | 2.36 | 5.49 |
| 2011-12 | 0.60 | 0.61 |  | 2.39 |  | 5.30 | 3.00 |

a Prices are absolute differences in regional reference node prices. b The Snowy region was abolished in the NEM on 1 July 2008. So no inter-regional price data are available from 2007-08. c Tasmania joined the NEM on 29 May 2005. So no inter-regional price data are available before 2004-05.

*Sources*: Commission calculations based on AEMO (2012i).

Third, the success of the merchant model in other countries (and in theory) is contingent on the presence of transmission rights and nodal pricing, which would involve fundamental design changes in the NEM.

* A shift to nodal pricing from regional pricing in the NEM would create more arbitrage opportunities for merchant investors in transmission (not just interconnectors) to earn revenue. Nodal pricing is discussed briefly in chapter 18 on identifying future transmission.
* Allowing merchant investors to assign physical and financial transmission rights over an interconnector would improve their flexibility in financing and managing the risks of their investment. This is discussed further in the next section.

Although the role of merchant interconnectors seems unlikely to expand within the current NEM, this might change marginally under the Commission’s proposals regarding NEM-wide transmission planning (chapter 15). Within this context, TNSPs could tender the building and operation of new interconnectors to merchant investors.

The focus of the remainder of this chapter is on existing regulatory biases against merchant interconnectors and on the scope for a beneficiary pays approach to interconnector investment.

## 20.2 Regulatory biases

Providers of merchant interconnectors compete with generators in supplying electricity.

In principle, there should be no regulatory biases in the NEM that favour one form of competition over another currently or in the future. Any biases could lead to inefficient outcomes in the supply of electricity in the NEM, with potential adverse effects on productivity and electricity prices. This principle applies not only to the current suppliers of electricity (and other services) in the NEM, but to future suppliers, including any new MNSPs.

Participants have not drawn the Commission’s attention to any major regulatory biases in the NEM towards or against MNSPs, although there may be some less important ones. While these biases may not directly affect the only existing merchant interconnector, Basslink (because it is protected by its commercial relationship with Hydro Tasmania), it is possible that they could in the future collectively frustrate the entry of new MNSPs.

### The impacts of new investment proposals by transmission network service providers

A major concern for a MNSP (and a generator) about a TNSP’s proposed investment in an interconnector is the risk that its assets will become less valuable. The additional capacity arising from the TNSP’s investment is likely to reduce inter-regional price differences and, thus, the ability of an existing MNSP to earn revenue as well as depreciate the commercial value of its interconnector before the end of its physical life.

As in competitive markets, such devaluation of existing assets could be an efficient outcome if a new investment proposal involves more productive interconnector technologies. Indeed, this could arise not just from a TNSP’s proposed investment, but also by the entry of future more productive MNSPs or even new generators. Asset devaluation is one of a suite of commercial risks that MNSPs bear when participating in the NEM.

However, the risk of asset devaluation from the investment decisions of a regulated entity, which does not face the full commercial risks of its investments, could potentially be seen as a form of regulatory bias against existing and proposed new MNSPs.

Under the Rules, TNSPs must generally apply the RIT-T to proposed investments, with an estimated capital cost of more than $5 million. The purpose of the RIT-T is to identify a credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market. The AER (2010h) has issued guidelines about the RIT-T. (Further details and a discussion about the RIT-T are in chapter 19.)

The wording of the Rules (and the AER Guidelines) in relation to the RIT-T is broad enough to ensure that the impacts of a TNSP’s proposal on MNSPs or generators (along with any other party) are taken into account. For example, the Rules require that the TNSP:

* provides ‘an assessment of reasonable scenarios of future supply and demand if each credible option were implemented compared with a situation where no option is implemented’ (clause 5.6.5B(c)(1))
* quantifies ‘any other class of costs that are determined to be relevant’ by them and agreed to by the AER before a project specification consultation report is made available to other parties, or else specified as a class of cost (clause 5.6.5B(c)(8) (iv))
* prepares a ‘project specification consultation report’, which, among other things, describes all credible options of which the TNSP is aware that address the identified need. These credible options may include market network services (clause 5.6.6 (c) (5))
* publicly consults on the RIT-T.

Also, the Rules enable the AER to intervene where other parties dispute the RIT-T’s conclusions.

The Commission further notes that its proposal for a NEM-wide planner approach to transmission expansions (draft recommendation 15.2), and with that a shift in responsibility for undertaking cost-benefit analysis of interconnector proposals away from TNSPs to AEMO, would allow a more consistent approach to taking account the impacts of TNSP investments on existing and proposed MNSPs and generators.

### Frequency control ancillary services

Frequency control ancillary services (FCAS) are used by AEMO to maintain the frequency of the power system within a small band around 50 hertz to ensure system security and reliability (box 20.4). AEMO procures FCAS in eight separate (but not regional) markets from market participants, mainly generators. In the last 12 months, the payments made by AEMO for FCAS totalled around $12 million (based on Commission calculations using AEMO 2012i).

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| Box 20.4 Frequency control ancillary services |
| AEMO is responsible for ensuring that the power system operates in a safe, secure and reliable manner (AEMO 2010, p. 1). It uses ancillary services to maintain key technical characteristics of the system, such as frequency, voltage and network loading.  Frequency control ancillary services (FCAS) are used by AEMO to maintain the frequency of the power system within a narrow band around 50 hertz. The frequency may change due to unpredictable shifts in the energy demand and supply balance. For example, if a generator trips, then there may be a sudden drop in frequency; or if demand is less than supply, then frequency may increase.  AEMO operates eight separate markets for the delivery of FCAS:   * regulation raise/lower (used for minor deviations outside a narrow frequency band of around 50 hertz) * contingency fast raise/lower (to be activated within six seconds to halt a large sudden change in frequency) * contingency slow raise/lower (to be activated in 60 seconds to stabilise the frequency after a large sudden change) * contingency delayed raise/lower (to be activated within five minutes to restore the frequency to normal)   The process AEMO uses to match supply and demand in each of the FCAS markets is similar to that used to dispatch generators in the energy market. Participants can offer or bid to supply FCAS in any of the eight markets. An offer or bid for a raise service represents the amount of MWs that a participant can add to the system in the needed time frame to raise frequency. AEMO procures its required amounts of FCAS in each of the eight markets in merit order of price as determined by the NEM dispatch engine (NEMDE).  During periods of high or low energy demand, the NEMDE may move the energy target of a generator or load in order to minimise the total cost of energy and FCAS to the market. This process is called co-optimisation and is an inherent feature of the NEMDE. |
| *Sources:* AEMC (2012p); AEMO (2010a, 2012h). |
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There is no provision in the Rules for MNSPs to make bids related to FCAS and, thus, earn revenue for the FCAS they transfer. As Hydro Tasmania said:

… no charging arrangement is specified in the NER [National Electricity Rules] to compensate a MNSP for transporting FCAS. Basslink currently transports FCAS but receives no fee for this service. Further, Basslink’s energy transport (and thus its actual market revenue) is reduced to ensure FCAS is carried. (sub. 41, p. 4)

In the development of the safe harbour provisions applying to MNSPs, both NECA and the ACCC (which had regulatory responsibility for the National Electricity Code at the time) envisaged that MNSPs could earn revenue from providing ancillary services (NECA 1999, vol. III; ACCC 2001, p. 126). However, when the Code changes were gazetted in December 2001, they contained no provision for MNSPs to make bids or receive revenue for transferring FCAS.

The AEMC considered this gap in the Rules in a rule change request by Hydro Tasmania in 2007 concerning the dispatch of scheduled network services. Although not central to its consideration of the rule change request, the AEMC expressed the view that there:

… appeared to be no clear reason for the lack of alignment between the FCAS and energy markets in terms of the ability of MNSPs to capture the value of the energy transfer but not that of the FCAS transfer. … this lack of alignment might be addressed through amendments to the MNSP rules; however, … this matter was outside the scope of [the] Rule change proposal. (2007b, p. 20)

There appears to be no obvious rationale for the different treatment of MNSPs and other market participants in FCAS markets. Although the revenues that MNSPs might earn from FCAS are unlikely to be large compared with the potential to earn inter-regional revenues from the transport of energy, denying MNSPs the opportunity to earn this revenue appears inappropriate. There is a theoretical case that this should be reviewed by the AEMC.

However, as Hydro Tasmania has noted (sub. 41, p. 4), the AEMC review would need to address complexities around the FCAS markets for what is likely to be a problem of ‘small materiality’. Therefore, the Commission considers that the AEMC review is not a priority, but might be undertaken as part of an omnibus review of lower priority Rule changes at a time deemed appropriate by the AEMC.

### Negative bidding by market network service providers

The AEMC is currently considering a rule change request from International Power-GDF Suez Australia and Loy Yang Marketing Managing Company to set a floor price of zero for the offers of ‘scheduled network service providers’ (AEMC 2012p). The term ‘scheduled network service provider’ is defined in the Rules and is regarded by the AEMC as equivalent to a MNSP (2012p, p. 2).[[6]](#footnote-6) If the rule change request is accepted by the AEMC, it would mean that MNSPs would be treated differently from generators under the Rules.

The proponents are concerned about the impacts of the bidding behaviour of Hydro Tasmania and Basslink on Latrobe Valley generators. When there is a transmission constraint in the Latrobe Valley, generators have an incentive to offer their energy at the price floor of -$1000/MWh in order to maximise their dispatch. If both Hydro Tasmania and Basslink (under direction from Hydro Tasmania) each bid at the price floors, the effective offer price of Hydro Tasmania’s energy at the Loy Yang connection point would be -$2000/MWh, ignoring losses. This offer price would effectively undercut the price floor — and the price offered by the Latrobe Valley generators — with the effect that Hydro Tasmania would be dispatched ahead of the Latrobe Valley generators, which would then lose revenue.

The proponents considered that the current bidding rules distorted the market as some generation is prioritised through an ‘artefact of the market rules’ (AEMC 2012p, p. 7). They stated that their proposed rule change would improve their contract market outcomes by ensuring that the most efficient generation would be dispatched and by providing greater certainty in dispatch for generators.

The AEMC has reported that it will release a draft determination on the rule change request in November 2013, with a final determination in January 2014.

The Commission notes that the rule change request being considered by the AEMC is in response to a specific problem — namely, disorderly bidding by generators in the presence of a transmission constraint in the Latrobe Valley, where one of the generators has a commercial relationship with the MNSP. Another option to address disorderly bidding is the introduction of optional firm access in the short term and, potentially, consideration of nodal pricing in the long term (discussed in chapter 18).

Adopting the rule change request to address disorderly bidding in the Latrobe Valley would have wider ramifications for any future MNSPs in the NEM. Setting aside the issue of whether future MNSPs would be commercially feasible, imposing a zero price floor on all MNSPs would treat them differently from generators under the Rules. Such differential treatment could impede any possible new entry by MNSPs and affect future competition in the NEM.

Concerns about the potential for Hydro Tasmania and Basslink to jointly exercise market power through combined negative bidding could possibly be addressed by the ACCC under Part IV of the *Competition and Consumer Act 2010*.[[7]](#footnote-7) If the ACCC found it appropriate to do so, it could request an undertaking from both parties that their bids in combination do not fall below the price floor applying to independent generators and MNSPs of -$1000/MWh. (Alternatively, the ACCC might potentially require that Hydro Tasmania is prevented from influencing the bidding behaviour of Basslink.)

The Commission notes that there is lack of clarity in the Rules as to what is the appropriate price floor for MNSPs. AEMO has administratively set this to be the same as that applying to generators under the Rules. Formalising this administrative action into a rule would create certainty for all market participants and would seem, in principle, to have merit. However, as with the inability of MNSPs to receive FCAS payments, such a rule change would not be a priority and might be undertaken as part of an omnibus review of lower priority Rule changes at a time deemed appropriate by the AEMC.

### Transmission rights

The NEM is underpinned by open access for the use of the transmission (and distribution) network. This applies to regulated and merchant interconnectors. As the AEMC (2011f) noted in its first interim report on the transmission frameworks review:

Currently the NEM operates under an open access regime. Generators have a right to connect to the transmission network, but this right does not extend to a firm right of access across the network to the RRN [regional reference node]. Generators instead are granted access when two conditions are met: they are scheduled in the merit order and there is no relevant congestion on the network. Generators do not have an inherent right to be dispatched, nor do they have a right to be compensated when constrained-off. (p. 57)

Several academics (for example, Hogan 1992) have emphasised that the ability to assign transmission rights (both physical and financial) is necessary for the commercial viability of merchant transmission. In particular, transmission rights enable merchant investors to raise finance and diversify their risks of investment. This was recognised by regulators in the United States and the European Union (appendix E).

When merchant interconnectors in the NEM first began operations, they entered or, at least, envisaged entering into contracts to assign property rights to other parties. For example:

* Basslink and Hydro Tasmania are parties to a 25-year agreement known as the Basslink Services Agreement, under which Hydro Tasmania acquired the rights to inter-regional revenues earned by Basslink in exchange for a facility fee.
* When Murraylink Transmission Company registered as a MNSP, it proposed in its access undertaking to the ACCC to sell the rights to bid the Murraylink interconnector into the NEM and to earn the associated revenues. These rights were to be sold in the form of physical and financial contracts (ACCC 2002, p. 1)

However, there is currently a lack of clarity in the NEM as to whether merchant interconnectors can assign property rights. This is largely because the access arrangements applying at the time these merchant interconnectors began operations (the National Electricity Market Access Code, which the ACCC authorised under Part IIIA of the *Trade Practices Act* 1975), were superseded when the Rules were introduced on 1 July 2005.

In the AEMC’s consideration of the rule change request concerning ‘scale efficient network extensions’ (AEMC 2011i, p. 5), some participants raised the absence of explicit property rights for merchant transmission.[[8]](#footnote-8) They claimed that a lack of property rights limited ‘market-driven’ options for building extensions, and that providing ‘firm access’ would increase investment in merchant transmission. Generally, these participants argued that any regulated framework should not crowd-out private investment. For example, the National Generators Forum, in response to the AEMC’s draft rule determination, said:

* One of the major failings, in our view, of the transmission system is the inability of generators or investors to make private investments in transmission assets with any certainty that the value of that investment will not be captured by other beneficiaries or directly by new connections. …
* The provision of property rights over merchant transmission has the potential to encourage greater investment in transmission by private investors …. (NGF 2010,   
  pp. 4–5)

The AEMC is currently considering access rights for generators (and to MNSPs) as part of its transmission frameworks review (AEMC 2011b, 2012j, 2012n). In its stage 2 report (2012j, n), it set out two options for generator access to the regional reference price: ‘non-firm access’ — which is basically clarifying the status quo access arrangements — and ‘optional firm access’ –– where generators can obtain financially firm access (as distinct from physical access) from a TNSP to their regional reference price through a compensation mechanism. (The options are described further in chapter 17 within the context of how they address disorderly bidding by generators.)

The AEMC’s optional firm access proposal is of relevance to merchant interconnectors in the following ways.

*Intra-regional access.* MSNPs use TNSP networks in the two regions that they interconnect. In the region from which they draw power (the exporting region) they are a demand-side user and so beyond the scope of the optional firm access. In the region into which they deliver power (the importing region), they are similar to a generator, in the sense that they inject power into the network at a specific node. Therefore, access provision to a MNSP in the importing region is the same as for a generator. A MNSP would then be able to decide how much firm access to procure using similar criteria to a generator.[[9]](#footnote-9)

*Inter-regional access.* The AEMC’s proposal enables a generators and retailers to purchase firm access rights that entitle them to the price difference between two regions on their ‘access amounts’ (the amounts of power to be transported). This is similar to the payment from the current settlements residue auction instrument. However, that payment is reduced when a generator causes the interconnector to be constrained off, as the payment is dependent on actual flows. Under optional firm access, the generator causing this effect would compensate the inter-regional access holder to ensure that, despite the reduction in interconnector flow, the access settlement payment did not decline. Although access payments would still be scaled back if transmission capacity were reduced, holders of inter-regional access rights would receive a firmer payment than current holders of settlements residue auction instruments.

The AEMC’s proposal for optional firm access appears to be a step forward in enabling MNSPs to not only establish property rights over their merchant interconnectors, but to acquire them in respect of other parts of the transmission network.

## 20.3 Beneficiary pays

Apart from merchant interconnectors, another approach to investment in interconnectors is for the potential beneficiaries of an interconnector investment to propose and finance the investment themselves. The approach could apply through either commercial contracts or a regulated arrangement involving the identification of beneficiaries and mandated contributions to the investment in accordance with the benefits they receive. The interconnector could be operated as a regulated or a merchant interconnector.

Variants of this approach in relation to interconnectors or transmission lines have applied in Argentina (box 20.5) and New Zealand, and are currently reflected in the US Federal Energy Regulatory Commission’s Order 1000.

In the NEM, a beneficiary pays approach already applies under the Rules to ‘non-regulated transmission services’, some ‘negotiated transmission services’ (which include ‘connection services’) and ‘extensions’.[[10]](#footnote-10) These services can involve the connection of generators and other customers to the transmission network, which are paid for by non-TNSPs. For example, Grid Australia identified the following non-regulated transmission services paid for, and owned, by non-TNSPs:

* Davenport to Olympic Dam 275 kV line owned by BHP Billiton (South Australia)
* Smithton to Woolnorth 110 kV line owned by a generator (Tasmania)
* Goonyell Riverside Expansion 132 kV private network (Queensland) (Grid Australia 2012a citing PWC 2012, p. 18).

In its transmission frameworks review, the AEMC recommended a number of measures for improving arrangements for connecting generators and other customers to the transmission system (AEMC 2012j). Many of its measures are intended to clarify what are the Rules in this area (including the meaning of the above services). For example, the AEMC proposes to clarify the Rules to allow a connecting party (such as a generator or large load) to issue a tender for the provision of an ‘extension’ (which the AEMC describes as the lines and other equipment between the connecting party’s facilities and the boundary of the assets used to provide the connection service such as a substation) or elements of that provision. A TNSP could participate in such a tender, but if requested by a connecting party must provide an extension as a negotiated transmission service, which has implications for the ownership and economic regulation of the extension.

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| Box 20.5 The public contest method in Argentina |
| The ‘public contest method’ for major transmission expansions was introduced in Argentina as part of major reforms to its electricity sector in 1992.  Although there were subsequent amendments to the public contest method, with its role being substantially diminished after 2002, its essential characteristics were:   * Beneficiaries, rather than incumbent transmission companies or regulators, propose, voted and paid for agreed major expansions. * The system operator used an ‘area of influence’ method to identify beneficiaries of the expansions and the proportion in which each would have to share in the costs. * The regulator still had to ensure that the proposed expansions met a ‘golden rule’ test, where the total cost of generation, transmission and unserved energy would be lower with the proposed expansions than without it. * Where voted on and approved by a majority of the beneficiaries, a competitive tender was put out to build, operate and maintain the expansion. The tender contract specified an amortisation period in which beneficiaries had to pay for the expansion according to their use. * After the expiration of the amortisation period in the tender contract, annual remuneration for the expansion followed the remuneration regime applicable to the existing network of the incumbent transmission company, which basically covered operation and maintenance only.   Papers reviewing the performance of the public contest method (for example, Littlechild 2011a, b; Littlechild and Skerk 2008d) found that:   * Criticisms that the public contest method did not work in relation to a ‘much needed’ Fourth Line were unwarranted. Although beneficiaries voted down an initial proposal, later research found that it was expensive, premature and uneconomic. In the short term, beneficiaries agreed to a cheaper alternative. When conditions later made the Fourth Line attractive, the beneficiaries ‘worked well’ to design, propose and pay for a line at a significantly lower cost than the initial proposal. * The public contest method enabled substantial investment in better transmission control systems (series capacitors). These more than doubled transmission capacity limits, which was more than sufficient to meet the increased demand and were more economic than building new transmission lines. * By 2007, around 40 public contest proposals for major expansions had been made, of which 35 were accepted by beneficiaries and all were implemented. The four largest approved expansions (not initiated by the Government) ranged from  $US25–$US256 million. * Bidding was generally competitive with tenders attracting an average of two to three bids. Independent companies won many of the contract tenders. |
| *Sources*: Littlechild (2011a, b); Littlechild and Skerk (2008a, b, c, d). |
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Some participants commented on the potential for a beneficiary pays approach, such as the Argentinian public contest method, to apply to interconnector investments. Hydro Tasmania said that:

… the most likely way of introducing their concepts is in the planning domain. The lead times between transmission and generation are mismatched and this means that generation has to follow in the general direction that transmission has set in relation to geography. The Argentinian approach would allow a more market based approach to planning by involving participants in making commitments to potential new investment. Some study would need to be undertaken in Australia to assess whether the lead times are such that this approach can work. (sub. 41, p. 5)

However, other participants were less supportive. For example, the National Generators Forum argued that:

... the “public contest method” and market based methods [are] more suited to simple, shared networks with few significant externalities and dedicated to few users. It may be suited also to shared connections in to a broader system. The NGF considers such approaches may well work in rail systems, such as the development of the coal rail network in Queensland and the Hunter Valley, where a few users can vote on proposed developments. Where the capital required is beyond the networking company then direct investment in infrastructure by users may also work, such as the Surat Basin rail system. By contrast the electricity network has over 20 million consumers (represented by their Regulators) and an array of suppliers (generators) of different types. A key problem with such approaches is competing objectives of users and instances where incremental costs are in excess of average costs of the system, pushing up costs for all users. (sub. 33, p. 8)

The AEMC suggested that a beneficiary pays approach would not be warranted if financial firm access rights were made available:

It is also not clear to the [AEMC] that consideration of radically different approaches, such as the Argentinian Public Contest method, is warranted. … In the NEM, currently, generators are not seen as beneficiaries of network expansions. While the Commission considers that there is a case for considering changes to the arrangements for generators in the NEM, our current view is that the approach that might be of most benefit would be the provision of financial firm access rights. (sub. 16, p. 8)

Read (2012) argued that the beneficiary pays approach to transmission investment used in New Zealand in the 1980s had not worked well in practice. At the time, investment in transmission could proceed if and only if a beneficiary coalition agreed to pay for it (and accept financial transmission rights in return). Read noted the absence of an electricity sector regulator at the time, which meant that broadly binding agreements could not be enforced and that Transpower (the transmission network provider) was impelled to negotiate with a variety of parties. Read concluded that the beneficiary pays framework needs a ‘strong, independent, and rigorously consistent’ regulator to coordinate the process and identify beneficiaries, represent ‘dispersed interests’ and make and enforce binding agreements.

In the Commission’s view, the main advantage of a beneficiary pays approach to interconnector investment would be that, in having to pay for the interconnector, beneficiaries would have strong incentives to get involved in the decision-making process and to ensure that the investment was the most cost-effective outcome.

However, there would be disadvantages associated with the approach were it to apply to interconnectors.

* If the approach was voluntary, there could be free-rider problems. There are potentially many beneficiaries from an interconnector — for example, many loads and many generators. All of them would have an incentive to defer paying for the interconnector in the hope that other beneficiaries value it enough to fund its development. Because of the incentive to free-ride, an interconnector might not be constructed in a timely manner or financed in a way that ensures its costs are efficiently allocated across all beneficiaries, or constructed to an efficient capacity.
* Even if a beneficiary pays approach was mandated (requiring the beneficiaries to pay), in a way similar to the Argentinian public contest method, identifying the beneficiaries, attributing benefits to each and allocating costs among them could be far from easy. For example, a usage-based method of allocating costs among beneficiaries may inadvertently discourage their full use of the transmission assets (in order that they be charged a lower cost share). Also, when the flow of power over an interconnector changes, so too do the beneficiaries, making it difficult to identify them in every case.
* There would also be the challenge of accounting for future beneficiaries who enter the NEM and allocating costs of the interconnector investment to them.

Accordingly, while there are conceptual advantages to a beneficiary pays approach, the Commission is not convinced that, in practice, a mandated approach akin to the Argentinian public contest method would be advantageous.

Having said that, the Commission’s proposal for a national planner approach to transmission expansions (draft recommendation 15.2) should be able to accommodate a *voluntary* beneficiary pays approach to interconnectors. Any party — for example, a generator, a load, a network business (or a consortium of parties) — should be able to voluntarily finance and operate a new interconnector (whether regulated or merchant) if it were commercially viable for them to do so. This proposal would, of course, need to satisfy necessary NEM-wide transmission planning and other requirements such as relating to reliability.

1. The economic literature on merchant investment in transmission in chronological order includes: Hogan (1992); Littlechild (2004); Joskow and Tirole (2005); Brunekreeft (2004, 2005); Knopps and de Jong (2005); Rious (2006); Leautier and Thelen (2009); de Hauteclocque and Rious (2010); Kapf and Pelkmans (2010); Hogan et al. (2010); Littlechild (2011a); and van Koten (2012). [↑](#footnote-ref-1)
2. The terms ‘scheduled network service’ and ‘scheduled network service provider’ tend to be used within the context Rules governing the coordinated central dispatch process (of bids and offers) operated by AEMO. For example, clause 2.5.2 (4) of the Rules provides that ‘scheduled network service providers’ are required to submit ‘a schedule of dispatch offers’ for their ‘scheduled network services’. [↑](#footnote-ref-2)
3. The National Electricity Code Administrator argued that the complexity of reviewing and approving interconnector schemes of smaller than the 30 MW threshold may outweigh the benefits, and that the threshold is consistent with the provisions applying to generation (NECA 1999, p. 100). The Australian and Competition and Consumer Commission in its determination authorising the initial safe harbour amendments (2001) to the National Electricity Code appeared to accept this argument. [↑](#footnote-ref-3)
4. The regulatory changes applying to the determination of the opening regulatory asset base of former market network services would not apply to Basslink, were it to cease to exist as a ‘market network service’. Instead, Basslink is subject to grandfathered provisions under the Rules (clause 11.6.20), which applied at the time it entered into operations. [↑](#footnote-ref-4)
5. In the United States, merchant transmission projects have included the Cross-Sound Cable between Connecticut and Long Island, New York; Linden which involved adding a Variable Frequency Transformer to an existing line between Linden, New Jersey and Staten Island, New York; Chinook, Zephyr and Southern Cross, which are transmission lines connecting new renewable generation plants to existing transmission networks in certain US States; and TresAmigas in New Mexico a proposed super interconnector joining three asynchronous grids (Werntz 2011). In the European Union, merchant transmission projects have included: EstLink between Estonia and Finland; BritNed between Great Britain and the Netherlands; Imera/East-West Cables between Great Britain and Ireland; and the Arnoldstein-Tarvisio interconnector between Austria and Italy (Cuomo and Glachant 2012). [↑](#footnote-ref-5)
6. The Rules classify ‘market network services’ as ‘scheduled network services’ (clause 2.5.3 (a)), which is probably why the AEMC treat scheduled network service providers and MNSPs as equivalent. See footnote 2 for an explanation of terms ‘scheduled network service’ and ‘scheduled network service provider’. [↑](#footnote-ref-6)
7. The Rules do not contain any provisions directly addressing the market power of NEM participants. Instead, clause 3.1.4 (b) states that chapter 3 of the Rules (which sets out the market rules) is not intended to regulate anti-competitive behaviour by market participants, which is subject to the Competition and Consumer Act. [↑](#footnote-ref-7)
8. These participants included the AER, Energy Australia, Macquarie Generation et al., National Generators Forum. [↑](#footnote-ref-8)
9. A MNSP can flow power in both directions and so there are potentially two importing regions in which it might seek firm access. [↑](#footnote-ref-9)
10. Each of these terms are referred to in the Rules but, as the AEMC noted in its transmission frameworks review, are not all clearly defined. [↑](#footnote-ref-10)