18 Efficient use of interconnectors

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| Key points |
| * The spot market in the NEM is an energy only market, in which lower bidding generators are dispatched first. The regional spot price is set by the marginal generator’s bid in each region (state) and all dispatched generators are paid at that spot price. In theory, this leads to efficient generation. In practice, this is not always true. * In the presence of congestion, the spot price tends to be high. Under current regulations, this encourages strategic behaviour by those generators constrained by line capacity. * Rather than making bids that reflect their true cost, they bid down to the (negative) market floor price to ensure dispatch, and are paid at the high spot price. Even an inefficient generator may supply power. This is termed ‘disorderly bidding’ * Disorderly bidding can result in productive inefficiency as less efficient generators are dispatched to meet demand. It can also ‘shut off’ interconnectors through distorted price signals. * The long-term effects are greater, and include inefficient generator location and investment and interconnector planning. * Potential ways of addressing disorderly bidding include applying formulae to market bids in the presence of congestion, or other longer-term methods that ensure generators face their true costs. * Allowing generators to purchase a given amount of guaranteed access to lines from transmission businesses (‘optional firm access’) would remove disorderly bidding incentives and introduce locational signalling to generators. (While this would introduce market signals, there would still be a need for transmission planning). * Electricity hedge markets are state-based. The lack of effective inter-regional hedging products has contributed to this. This has implications for: * liquidity in the hedge market * generators’ choice of location for new investment * the ability of generators to use any market power. * Publishing past hedging positions would increase market transparency, and enable more effective regulation of market power issues, but also has some costs. * Reforms that address disorderly bidding also address the root cause of problems in the hedge market. * In particular, optional firm access would allow firm access rights across interconnectors, which could replace existing financial instruments. |
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Several elements of the regulatory framework — incentive regulation, regulatory tests and planning — determine the *amount* of investment in interconnectors in the National Electricity Market (NEM). However, the *use* of interconnectors depends on the activity of market participants in buying and selling power in the ‘spot’ (or energy) market, and on congestion in intra-regional transmission lines. The way participants manage their risk in the hedge market can also affect actual power flows. If either of the markets operates inefficiently, interconnectors could be underutilised. As such, reforms to the markets (as distinct from specific interconnector regulation) could provide benefits from a greater degree of interconnection.

This chapter examines the operation of, and incentives set by, both the spot and hedge markets in the NEM.

## 18.1 The spot market

Because electricity cannot readily be stored and it is generally not possible to determine which generator provided power to which customer, the NEM operates as an ‘electricity pool’ that matches supply and demand.

The NEM is an ‘energy-only’ market, and does not include a separate capacity market.[[1]](#footnote-1) Aside from hedge contracts, generators earn their revenue solely from the spot market.

The spot market in the NEM is subject to many detailed rules, some of which are necessitated by the nature of electricity, and some of which are legacies of the development of the NEM.

### Operation of the spot market in the NEM

The general operation of the spot market in the NEM is discussed in chapter 2, but several features warrant specific mention in the context of interconnectors. Dispatch in the spot market is determined by generator bids at five minute intervals.[[2]](#footnote-2) These generator bids are dispatched in ‘merit order’, with lowest price bids first, with progressively more expensive generation called upon as demand increases. AEMO matches these bids — subject to a complex series of constraint equations managing congestion and transmission losses — to equate supply and demand in each five minute period.

The market price is therefore equal to the bid of the marginal generator — that is, the last, most expensive, generator required to match supply and demand.[[3]](#footnote-3) As such, for all bar the marginal generator in a given region, any generator receives a price for their power that is higher than its bid price. Accordingly, bids determine the quantity of power dispatched from non-marginal generators, but not their revenues.

As the NEM is a ‘zonal’ market, there is a separate price for each of the NEM’s five regions.[[4]](#footnote-4) All generators and loads within a region are settled at that regional price, calculated at the nominated ‘regional reference node’ (RRN). At times when demand is sufficiently low and transmission lines and interconnectors are not congested, these regional prices should equate (allowing for transmission losses). However, congestion can cause price separation between the regions. As noted in chapter 17, such ‘price separation’ occurs roughly one-third of the time and is increasingly common (although the degree of difference between prices is in most cases small).

A further feature of the NEM is that the energy market is ‘co-optimised’ with the market for ancillary services (services required to ensure the stability of the power system, and facilitate its recovery). This means that the algorithm for calculating market outcomes ensures that energy demand and stability requirements are jointly met at the lowest cost. Although this co-optimisation might be efficient, it can lead to some outcomes that, when viewed from the perspective of the energy market alone, may appear perverse. For example, co‑optimisation can sometimes be the reason for ‘counter-flows’ along interconnectors — that is, where power is observed to flow away from a higher-priced region to a lower-priced one.

## 18.2 Disorderly bidding

Bizarre outcomes can occur in the NEM. While the near-instantaneous matching of supply and demand is an impressive feat of market coordination, it is possible for the market signals to ‘malfunction’. In these cases, higher cost generators can sell power into the spot market, even where alternative lower-cost generators could provide this power — ‘disorderly bidding’.[[5]](#footnote-5) Although the main source of these peculiar outcomes is congestion on intra-regional lines, it can have significant effects on interconnectors.

When there is no congestion within a region, generators have an incentive to bid close to their true marginal cost. Bidding too low might result in ‘follow‑the‑leader’ behaviour by other generators competing to be dispatched, resulting in a spot price that might be lower than the generator’s marginal cost. Depending on the amount of power dispatched (and their positions in the hedge market), this could be a ruinous outcome for a generator. Conversely, bidding too high could mean not being dispatched when it would have contributed to profits.

However, congested transmission lines create different incentives. Congestion on a transmission line that links one group of generators to the network means that these generators are unable to dispatch all of their supply. Consequently, generators not affected by the constrained line must supply more power than usual. Given the operation of the ‘merit order’ dispatch, and especially at peak demand times, this will mean that a higher-cost generator will be dispatched for at least some of the power required.

Knowing that their bid will not affect the regional price and faced with limited line capacity, the constrained generators’ objective changes. They now have an incentive to bid as low as possible, in order to maximise their share of dispatch on the congested line and to maximise their returns.

Since generators are able to bid a (negative) price floor, currently ‑$1000 per MWh, all constrained generators with a marginal cost below the likely regional spot price will bid at the price floor in an attempt to be dispatched. Under the rules, when there are tied bids, capacity is allocated to all of the constrained generators in proportion to their rated capacity. Therefore, even if one low-cost generator were able to meet the full capacity of the congested line, they would have to share supply with higher-cost generators. This results in a higher overall cost to produce electricity for the region.

Box 18.1 describes a simplified example where a line connecting two generators to the RRN is constrained. In addition to a fault or outage on a line, congestion can also arise when a new generator connects to an existing line. Where the new generator’s capacity tips the total generation supply above the existing capacity of the transmission line, the net effect is the same — generators competing for limited capacity where their bids will not determine the spot price have an incentive for disorderly bidding (AEMC 2011f, pp. 210–12), which has been observed in bidding patterns by the AER (2010c, p. 3).

The intrinsic problem is that with transmission constraints, and with the spot price set elsewhere in the region, generators no longer face incentives to bid down to their marginal costs. The duration of constraints can vary — for example, an outage for a few hours, as opposed to the time to construct new transmission to accommodate new generation. Depending on this duration, the demand conditions at the time, and the amount of supply affected, the costs can be large, but transient. While the ACCC has some powers to prevent this, in practice there are significant difficulties in identifying and addressing transient market power, which can manifest as either disorderly bidding, or the more ‘traditional’ withholding of supply. (Generators have a legal right to change their bids, and there may be many reasons for doing so.)

Though disorderly bidding can cause a range of problems *within* a region, for the purposes of this inquiry, the main problem is the potential impact on the performance of interconnectors (described in a simplified example in box 18.2).

In the spot market, generators in one region receive the *spot* price of that region, even if they ‘sell’ their power (by contract) to another region across an interconnector (though they may buy hedge products such as ‘inter-regional settlement residues’, described below, to align their returns with prices in the other region, as discussed below, current methods of hedging are imperfect). Generators in an unconstrained region face the ‘normal’ incentives to disclose their true marginal cost when bidding, while those in regions with constrained lines have an incentive to enter disorderly bids.

Regulated interconnectors cannot enter retaliatory bids (in the manner that competing generators can), and are instead treated as if they have bid at the RRN in the exporting region. As such, the market would perceive a low cost generator (with say a marginal cost of $25 per MWh) in the unconstrained region as ‘more expensive’ than a higher-cost generator in a (constrained) region engaged in disorderly bidding (‑$1000 per MWh) on the other side of an interconnector. In effect, this prevents the supply of lower-cost power across the interconnector into the higher‑priced region.

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| Box 18.1 Disorderly bidding in a single region |
| Disorderly bidding in a single region. This figure shows how marginal costs from generators impact upon the regional reference pricing node. When there is a line constraint, the price of power is high, and the generators affected by the constraint want to bid to get the high spot price. The best way of doing so under the Rules is to set a negative price to win the bid and get despatched. Since all constrained generators do this, they both get despatched, despite one being more efficient than the other.  In the example above, the transmission line connecting G2 and G3 to the load centre at the RRN is usually able to carry over 200 MW of power. In this ‘unconstrained’ case, to meet the region’s demand of 250 MW for one hour, the dispatch solution would involve total production costs of $10 200 and would be divided amongst the generators:   * G3: 120 MW (marginal production cost $1200) * G2: 80 MW (marginal production cost $4000) * G1: 50 MW (marginal production cost $5000)   In the presence of a constraint that limits the line to the cheaper generators to 150 MW, G1 must be dispatched for more power (100 MW up from 50 MW). In this situation, G2 and G3 know that their bids will not affect the regional price, so their only incentives will be to maximise their dispatch, not reflect their marginal costs. Both generators will attempt to undercut each other, resulting in bids of -$1000. G2 and G3 will then be dispatched in proportion to their rated capacity. This changes the dispatch solution:   * G3: 90 MW (marginal production costs $900) * G2: 60 MW (marginal production costs $3000) * G1: 100 MW (marginal production costs $10 000)   This results in a total production cost for power in the region of $13 900.  If bids represented ‘true’ marginal costs, G3 would be dispatched for 120 MW, G2 for 30 MW and G1 would still supply 100 MW. This ‘constrained optimisation’ solution has a total production cost of $12 700. As such, in this example, the ‘cost’ that can be assigned to disorderly bids is $1200 (with the remaining $2500 due to the constraint). |
| *Source:* adapted from AEMO (sub. 32). |
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| Box 18.2 Disorderly bidding between regions |
| Disorderly bidding between regions. This figure shows how constraints on lines impact on marginal costs between regions. Sometimes the process described above can affect power transferring along an interconnector.  As in box 18.1, when faced with a constrained line, and competition from other generators (whose power must be transferred over an interconnector from region 2), G2 will enter a bid of -$1000.  In region 2, the marginal bid has set the region’s spot price at $50, and regardless of any power supplied to region 1, a generator in region 2 can only earn $50 per MWh. As a regulated interconnector cannot ‘retaliate’ in the market dispatch engine’s calculations (by also making a bid of -$1000), G2’s bid of -$1000 will be treated as a cheaper bid. As such, G2 will run in preference to all generators in region 2, even though there may be many generators with a marginal cost of at least half the fuel cost of G2. This effectively ‘cuts off’ the interconnector.  In more extreme cases, G2 could export power to region 2, resulting in counter-flows, resulting in AEMO attempting to ‘clamp’ the flow (see text). |
| *Source*: AEMO (sub. 32). |
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Disorderly bidding is most likely to occur during periods of peak demand — when lines are more likely to be constrained, and when higher cost ‘peak’ generators are more likely to be called on to meet demand. Ironically, it is precisely at these times when interconnectors should be in most use.

In some circumstances, an even more peculiar outcome arises. A high‑cost constrained generator bidding at -$1000 per MWh is almost certain to have spare capacity (that cannot be dispatched to its regional reference node due to an intervening constraint, but could be dispatched in another direction). Depending on the architecture of the network, its spare capacity could be sent across the interconnector, displacing lower-cost generators in the other region. In these instances of ‘counter-flow’, the availability of the interconnector accentuates the inefficiency of the disorderly bidding.

When counter-flow occurs, negative inter-regional settlement residues (section 18.5) can accrue. To avoid this, AEMO is obliged to ‘clamp’ (artificially reduce) the interconnector flows to zero.[[6]](#footnote-6) The presence of this obligation is one indicator of the prevalence of disorderly bidding as a problem in the NEM.

### Size of the problem?

While disorderly bidding is a well-known phenomenon within the NEM,[[7]](#footnote-7) some people question whether it matters enough to require a regulatory remedy.

The largest and immediate effect of disorderly bidding are transfers between parties (between generators, and in cases where the region’s spot price increases, between generators and customers). For example, AEMO cited one instance where disorderly bidding lasting just a few hours (from 10.30AM to 5.30PM) had a substantial impact on prices, and on the overall amount paid for power in New South Wales. In this instance, a constraint on the 70/71 transmission lines between the Mt Piper and Wallerawang power stations, combined with generators’ bids, led to spot prices in New South Wales in some instances in excess of $5000 per MWh, and saw the dispatch engine attempting to reverse interconnector flows away from New South Wales (AEMO 2010g, p. 11). AEMO estimated the revenue impacts of this case of disorderly bidding by comparing the actual outcomes with a ‘re-run’ of the dispatch model using assumed ‘normal’ bidding conditions. AEMO concluded that:

NSW prices between 10:30AM and 3:30PM averaged $90/MWh in the re-run against the actual average of $4,917/MWh, which would have reduced pool settlement by about $300 [million]. (AEMO 2010g, p. 11)

Another example, from 4 February 2010, highlights the interaction between network effects, disorderly bidding and demand response, and the effect this has on price volatility and interconnector flows (box 18.3).

Some have argued that the impact on prices is largely a ‘wealth transfer and not a loss of economic efficiency’ (Frontier Economics 2012, p. 7). However, there are some efficiency effects.

Productive efficiency is lower for the period of disorderly despatch as progressively less efficient generators must be relied upon to meet demand (with the inefficiency mainly being the use of higher cost fuels). As (the bulk of) current generation technologies and fuel sources in the NEM are relatively homogeneous, the differences in short-term marginal production costs are probably not significant.[[8]](#footnote-8)

Moreover, when interconnector flows are reduced (or stopped) by disorderly bidding, it affects the ability of market participants to hedge transactions between regions (section 18.5). This causes greater uncertainty for hedging parties, increasing the cost of hedging and flowing through to higher electricity retail prices.

Further, although they are difficult to enumerate, there are likely to be larger costs in the long term. First, reduced certainty of dispatch due to disorderly bidding can increase the perceived risk of a generation investment, which could discourage (otherwise efficient) investment in new generation (AEMC 2011f, p. 33).

Disorderly bidding widens the margin between the spot price and the usual bidding price of generators (which they typically bid down to their marginal costs). Generators recover their fixed costs from the revenue associated with the spot-bid price margin. Distortions in that margin will affect the future decisions of generators to invest. They could also affect maintenance and asset life decisions if a plant that is able to ‘survive’ on returns from instances of disorderly bidding (rather than by competing on the basis of an efficient marginal cost) is kept online longer than it otherwise would be. Therefore, generators will have a greater incentive to locate new investments in (congested) areas of the transmission network where they can better control dispatch outcomes through disorderly bidding.

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| Box 18.3 Disorderly bidding in New South Wales on 4 February 2010 |
| Early in the day of 4 February 2010, part of the network in Sydney’s Central Business District (CBD) was taken offline for planned maintenance. By mid-morning, potential overloads were identified between the CBD and Sydney South. To remedy these overloads, the line from Kemps Creek to Sydney South was taken out of service at 10.25 am. Flow-on effects through the transmission network then saw flows exceed limits on the Mt Piper to Wallerawang transmission lines (160 kms west of Sydney).  The figure below depicts prices during the morning of these overloads. In the face of the line constraint, the quantity of negative offers from generators increased, from 6200 MW at 10.30 am to 10 600 MW at 10.40 am (New South Wales aggregate demand at the time was just below 11 000 MW). The effects of the constraint set the price to $10 000 MW/h (the market price cap at the time) for three dispatch intervals from 10.30 am.  The high prices caused an apparent demand response, which saw a 540 MW reduction in New South Wales demand at around 11 am. This, combined with increasing negative offers from generators saw a dramatic drop in the five minute price, to the price floor of -$1000 at 11.05 am (prices are settled on 30 minute periods, as the average of the 6 intervals, so actual settlement prices did not drop so severely). Following the reduction, demand rose, generators reduced their negative bids, and the price returned to nearly the price cap for four five-minute intervals.  There was another demand response (roughly 350 MW) at 12 pm, leading to a (less dramatic) fall in prices. At 12.40 pm, the Mt Piper transformer returned to service, relaxing the Kemps Creek to Sydney South constraint. As a result, unconstrained generation with a negative bid became marginal, and prices dropped to -$996 at 12.45 pm.  These constraints also reversed the flow of the interconnectors. QNI was forecast to import 1050 MW into New South Wales, but instead exported 446 MW to Queensland. Similarly, the Vic–NSW interconnector was forecast to import 1135 MW, but the constraint forced flows into Victoria of up to 1301 MW.  **Five minute price and demand, NSW, 4 February 2010**  Five minute price and demand, NSW, 4 February 2010. This figure shows the five minute price and five minute demand over a 24 hour period. Two areas are highlighted which indicate times of demand reduction. |
| *Sources*: AER (2010d), Lerchbacher (2010) . |
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Accordingly, generators may locate in the ‘wrong’ places to take advantages of constraints, particularly in relation to interconnectors. There is some evidence that this occurs. The AER has suggested that the Kogan Creek 760 MW capacity coal plant in Queensland was located to take advantage of the revenues created by disorderly bidding. The plant is located between the Queensland/NSW interconnector (QNI) and a congested part of the Queensland transmission network (AER 2010c, p. 12). The AER claimed that increases in output from Kogan Creek from 500 MW to 750 MW decreases power imports across QNI ‘on an almost one for one basis’, to the point that — when Kogan Creek runs at capacity — imports across QNI stop (AER 2010c, p. 13).

Additionally, common ownership of even structurally separated generation and transmission could potentially delay responding to the need for a transmission upgrade.[[9]](#footnote-9)

Finally, the observed flows on an interconnector act as inputs into transmission planning processes. Where flows are artificially reduced by disorderly bidding, forward planning about the need for (or size of) upgrades for interconnectors and intra-regional transmission lines can also be affected.

Overall, while the short-term efficiency effects of disorderly bidding may appear small, the longer-term effects on financial markets, generator location, interconnector flow and planning are of (significantly) greater concern. Given that, there are compelling grounds to ensure that any future framework for transmission planning and pricing addresses disorderly bidding.

## 18.3 Potential solutions

An efficient solution to disorderly bidding should motivate generators to make bids, or face prices, close to their ‘true’ marginal costs at the point of generation. There are many possible options for achieving this, with tradeoffs between their effectiveness and their ease of implementation.

At one end of the spectrum is the imposition of a formula on generator bids at times of congestion. A simple approach would be to use the historically observed ‘system normal’ bidding behaviour of generators. Alternative methods include de-linking generators’ returns from the regional price in the presence of congestion, for example by making them face their ‘nodal’ (or local) price, potentially packaged with hedging options.[[10]](#footnote-10) By removing the incentive to bid low in order to maximise dispatch, such imposed formulae can resolve the short-term dispatch efficiency issues caused by disorderly bidding. However, they are not necessarily the best method for dealing with longer-term issues such as generator investment and location.

Alternative approaches taking a long-term view can still realise the short-term benefits of these simple options, but can also more directly influence the timing and, particularly, the location of generator investments, introduce greater market signals to transmission investment and improve the alignment of generation and transmission investment. Improvements in these factors would have subsequent benefits for interconnector use and investment.

Various reviews have canvassed long-run solutions. Of most relevance is the AEMC’s current Transmission Frameworks Review (TFR). The TFR examined three aspects of the regulatory framework for transmission: generators’ certainty of access to the regional reference price, transmission planning, and arrangements for connecting generators to the network. Of these, the options for generator access are relevant to disorderly bidding issues.

In the First Interim Report (AEMC 2011f), the AEMC contemplated five packages for reform of generator access to the network.[[11]](#footnote-11) In the Second Interim Report (AEMC 2012j), the AEMC focussed on two options:

* Optional firm access (OFA): in which generators can purchase from a Transmission Network Service Provider (TNSP) a privileged financial right to a given amount of the capacity of a transmission network (‘firm’ access). The generator does not have to actually dispatch power, but any other generator displacing the purchased capacity must pay the generator that has acquired firm access. Accordingly, firm access provides firm *financial* access (as distinct from physical access) to the regional reference price through a compensation mechanism.
* Non-firm access — effectively the status quo. It would not prevent disorderly bidding and its associated significant problems.

Of these, only the first (optional firm access) can address the long-run inefficiencies due to disorderly bidding, and is the Commission’s preferred option.

### An optional firm access reform package

The OFA package proposed by the AEMC is a complex and integrated package that aims to address several key issues, including disorderly bidding, dispatch certainty for generators, locational signals for generators and the lack of market signals for transmission operation and planning.

The key features of the AEMC’s package (AEMC 2012j, pp. 22–23) are:

* *Purchasing firm access:* generators would have the option of purchasing a quantity of ‘firm’ access from TNSPs, or leaving all (or part) of their output subject to non-firm access.
* *Access pricing:* there would be no charge for non-firm access, but firm generators would pay TNSPs a charge reflecting the long-term incremental costs (LRIC) of increasing the network capacity over time. LRIC is a particular form of the broader principle of long run marginal cost (Marsden Jacob Associates 2004).[[12]](#footnote-12)
* *Firm access standard*: TNSPs would be required to plan and operate their network to provide a level of capacity necessary to meet the purchased levels of firm access(analogous to customer reliability standards, but targeting outcomes that matter for firm generators).
* *Access settlement*: where non-firm generators are dispatched ahead of firm generators, they are liable to compensate firm generators for any loss of dispatch. In this manner, ‘firm’ access refers to certainty of financial return, rather than physical dispatch. This settlement process affects generator bidding behaviour in a similar manner to congestion management mechanisms, and reduces incentives to disorderly bid.[[13]](#footnote-13)
* *Inter-regional access:*Generators and retailers could purchase firm inter-regional access rights for a given amount of capacity on interconnectors. These purchases (combined with bids from other beneficiaries) would be used to direct and fund future interconnector expansions (this element of the package is discussed further in chapter 20).

The package also requires additional regulation of TNSPs as the monopoly providers of firm access. This regulation would include (AEMC 2012j, pp. 35–7):

* requirements to provide information to generators requesting firm access in a timely manner, and to negotiate in good faith.
* transparency of any approved LRIC pricing methodology.
* changes to revenue regulation. TNSP revenue from firm access sales would not be capped, but the prices for firm access would be regulated (to ensure the methodology used was consistent with LRIC). Instead, an estimate of the expected revenue from firm access charges would be ‘carved out’ from total revenue requirements, leaving the remainder of the revenue cap to be spread across users of load services through transmission use of system charges
* quality regulation in the form of financial incentives that penalise TNSPs for shortfalls in providing the subscribed levels of firm access. These financial penalties would be transferred to affected generators through the access settlement process.

The AEMC’s optional firm access package also includes a lengthy transition process that calculates generators’ access requirements, scales them back to the existing capacity of the shared network, and gifts generators with (temporary) firm access based on their past use. These transitional access rights would be removed progressively over a period of up to five years, or over at least the remainder of the existing regulatory determination period (AEMC 2012j, p. 39). During the transition phase, TNSPS would also be exempt from financial quality incentives.

Sudden changes in regulation can create uncertainty and confusion amongst stakeholders, particularly in the case of a complex reform to an already complex area, such as electricity. The approach suggested by the AEMC aims for a smooth transition by phasing in changes through endowing generators with initial firm access rights. This would allow generators (and TNSPs) to ‘learn’ and become accustomed to the reforms over time. On the other hand, providing all generators with an endowment based on existing use could simply delay the benefits of optional firm access and (temporarily) create a more complicated version of the status quo (with no relativity in access pricing to induce changed investment decisions by generators). Given the extent of consultation through both the Commission and the AEMC’s process, there may be scope to shorten this transition period in order to access the benefits from reform sooner (or, given that take up of the reform is optional for generators, another option would be to simply pre‑announce the changes in advance of implementation).

While the OFA package is wide-ranging, its most important elements are the access settlement process, and the ability to pay for firm access (on both intra- and inter-regional lines).

### The access settlement process — a congestion management mechanism

The access settlement component addresses transmission congestion. Through a series of complex formulae (AEMC 2012n, pp. 103)**,** the access settlement process provides compensation to firm generators who were not dispatched due to congestion. The compensation is paid by the (generally) non-firm generators who contributed to the congestion. This settlement process is a transfer between generators that operate separately from the market dispatch process (which would continue to function as it does now). As such, the settlement process does not increase the total price the wholesale market pays for electricity. In fact, it is designed to address disorderly bidding and encourage generators to bid at their marginal costs, reducing overall costs.

The compensation for generators takes the form of the ‘flowgate price’ for each MW of firm power that is not dispatched.[[14]](#footnote-14) The flowgate price is the marginal benefit of relaxing a constraint affecting the flowgate.[[15]](#footnote-15) This is equal to the amount that the market currently pays for that marginal MW (the regional reference price) less the cost of a ‘cheaper’ MW that could be accessed from the generators using the constrained flowgate (the locational marginal price of the affected generators). Where a firm generator is the marginal generator at its node, and enters a bid equal to its marginal cost, the flowgate price will be the same as the profit margin that the constrained firm generator would receive from dispatching that MW. Therefore, firm generators’ profits are the same regardless of whether they are dispatched or not, eliminating any incentive for firm generators to enter disorderly bids.

Conversely, other generators must pay compensation equal to the flowgate price for each MW where their dispatch amount exceeds their own firm access entitlement (which may be zero). If a non-firm generator entered a disorderly bid, they would still receive the regional reference price, but would incur their costs for units produced, and would also be liable to pay compensation through the settlement process. This would lead to losses and therefore remove the incentive for disorderly despatch. Where the non-firm generator is more efficient than a firm one, they would still pay compensation, but should still profit from being dispatched (box 18.4).

Where a given flowgate (or indeed, the entire NEM) was used by only non-firm generators, their entitlements would be a proportion of the available transmission capacity, based on their available generation capacity. So, if two generators of 600 MW and 400 MW capacity sought to use a transmission line of 500 MW capacity, their respective ‘entitlements’ would be 300 MW and 200 MW. The degree (and direction) of compensation flowing between non-firm generators would be determined by the difference between this (implied) entitlement and the dispatch amount for a given generator.

For a non-firm generator to make a contribution to profit from being dispatched, rather than staying idle (and regardless of the presence of any firm generators), its marginal cost must be less than the locational marginal price. In this way, the access settlement mechanism ensures that, even in the presence of congestion, generators have an incentive to bid in a manner that reveals their true marginal costs. As such, adoption of the OFA package would ensure that, at the very least, a congestion management mechanism would apply in the NEM. This element alone should address disorderly bidding and provide (at least short-term) benefits.

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| Box 18.4 The access settlement process |
| The access settlement process. This figure shows the process of dispatch and energy settlement between nodes on a constrained line.  If the line between node X and node Y is constrained, the combined dispatch of G2 and G3 cannot be more than 100 MW. With a lower bid, the non-firm generator (G2) is dispatched ahead of the firm generator (G3), constraining G3 off by 50 MW.  Dispatch and energy settlement occurs as it does currently, with the regional reference price set at $100 by the marginal G1, who dispatches 100 MW, and receives $10 000. G2 dispatches 50 MW for $5000 and G3 50 MW for $5000, for a total of $20 000.  Given G2’s usage of the constrained flowgate (50 MW) exceeds its entitlement (0 MW), it will be required to pay compensation in the *access settlement* process (separately from *energy settlement*). As G3’s usage (50 MW) was below its entitlement (100 MW), it will receive compensation, calculated as entitlement minus usage, multiplied by the flowgate price ($40). After compensation, the generators’ revenues are:   * G1 is not affected by the constraint, so it receives only the energy settlement: $10 000 * G2: receives energy settlement, *minus* compensation: $5000 – 50\*$40 = $3000 * G3 receives energy settlement *plus* compensation: $5000 + 50\*$40 = $7000   Assuming G3’s bid is its marginal cost, if it was dispatched for the extra 50 MW, it would have received $5000 more, but incurred costs of $3000, for additional profits of $2000. So the compensation has put G3 in the same financial position as if it were dispatched.  G2’s incentives depend upon its marginal costs. If its costs are below the local price ($60), then it will profit. If its costs are $60 per MW, it will be indifferent. If its costs are higher than the local price (say $70 per MW), but it bids below the local price, it will be dispatched (and receive $5000), incur production costs ($3500) and owe compensation ($2000), resulting in an overall loss (-$500). In this way, the access settlement process discourages disorderly bidding. |
| *Source*: adapted from AEMC (2012j). |
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### Procuring firm access — a long-term signal

Under the OFA package, the ability of generators (and in the case of regulated interconnectors, retailers) to purchase a quantity of firm access from TNSPs would operate as a two-way signal.

For transmission companies, the signals are firm access requests by generators. This creates ‘market-driven’ signals for transmission investment because generators in a competitive environment seek investment to meet their needs. It avoids sole reliance on planning by a TNSP. This should lead to a better alignment of transmission investment with generation needs. Further, procurement of large quantities of lines by generators is less of a social concern than any potential ‘gold-plating’ by TNSPs under the current economic regulatory regime. As generators generally operate in a workably competitive market, any incorrect decisions to procure firm access will result in fixed costs that are not fully recouped through the wholesale market, with the loss being borne by generation owners, rather than spread across all users through increased transmission charges.[[16]](#footnote-16) Thus, those making the decision would bear the risk. Similar benefits would arise from generators and retailers being able to purchase firm access across interconnectors.

For generators, the prices charged by TNSPs for firm access act as the market signal. Provided regulation prevents TNSPs from using their monopoly position to increase charges, prices should reflect the net present value of the LRIC of providing the requested capacity. The use of the LRIC should provide two important signals (AEMC 2012j, p. 32):

* *locational*: as longer transmission lines would need to be built, generators in remote locations would pay a higher price than those close to loads (or the RRN)
* *congestion:* where a generator located in a congested part of the network, and requested firm access, expansion of transmission lines would be immediately required for the TNSP to provide the requested firm access. Where a generator located in an area of substantial spare transmission capacity and sought firm access, any necessary investment would be a long way into the future. As such, the net present cost of locating in an uncongested area would be lower than in a congested area, as the transmission investment needed to meet access requests would not be required for some time into the future.

Cost-reflective pricing of firm access ensures that location and congestion would be one element of the overall decision to invest in new generation. Other factors, such as proximity to natural resources or load (demand centres), may often be more important. Consequently, generators could still choose to locate in relatively congested areas. The difference is that, under the OFA package (through both access pricing and the settlement mechanism), the generator should have considered all the appropriate costs and made a decision that is, overall, an efficient one.

### Optional firm access and transmission planning — complements or substitutes?

The network transports power from generators to load centres. Under the OFA package, the generation side of transmission investment is driven by the market signals described above. This raises the issue of how OFA interacts with, or indeed if it replaces, transmission planning arrangements.

While the introduction of market signals would improve the coordination of generation and transmission investment, it would not necessarily result in optimal network development. For it to do so would assume that users’ interests directly aligned with suppliers’, and that generators are motivated to demand transmission investment at the right place, and at the right time, for consumers.

Although markets within the NEM can achieve impressive feats of coordination, their present structure does not result in a complete alignment of generator and user interests in terms of transmission investment. For example, generators’ financial interests rely on delivering power to a regional reference node. As such, their firm access requests will relate to lines between generators and the RRN. Load centres that require transmission from the RRN with little to no local generation may be under-provided if transmission investment were solely directed by generators.

In the future, were the demand side able to obtain firm access (through for example, retailers requesting access), these concerns could be alleviated as transmission could be more directly driven by consumer need. However, in order to do so, customers would need to (at least partly) face cost-reflective prices. Given the NEM-wide rollout of smart meters could take a considerable time (chapter 11), retailers would not see any degree of efficient response to price changes (in timing or quantity of use) for some time. Consequently, any signals they would be able to send through purchasing firm access would also be distorted.

Further, even in the presence of (undistorted) signals from both sides of the market, there is likely to be a role for some independent oversight of the planning of the transmission network (whether it be the current system, the hybrid system currently favoured by the AEMC, or a NEM-wide planner as recommended by the Commission in chapter 15).

As discussed in chapter 15, it is difficult to correctly align the incentives of private actors (with limited liability) with potential high impact, low probability events. While generators (and retailers) would have some incentive to avoid such catastrophes, they would not bear the full costs of protracted and widespread blackouts (if, say, transmission lines to Melbourne or Sydney were to go down for an extended period). Given the possibility of such extreme consequences, and the inability with transmission to be able to confidently use lead indicators to monitor the reliability of the network, some planning oversight would still be necessary over the long-run.

There would also be precautionary grounds for detailed planning and identification of constrained transmission lines for at least an interim period. While it appears to be elegant and theoretically sound, OFA may not work perfectly, and, if implemented, should be evaluated before contemplating the removal of the role of detailed independent planning. The Commission also notes that even systems in the United States that use full nodal pricing retain at least some role for a regional transmission planner (chapter 15).

However, having both transmission planning and OFA mutes the benefits available from each. For planning, any benefits available from improved coordination would only apply to a subset of the network, as transmission investment for generation would be market-driven. For the OFA package, the presence of lines built to meet reliability standards introduces complications. While there may be some radial lines in the NEM that carry power solely to a load, or some that only serve generators without load centres, the bulk of lines will serve both generation and load. As such, it may be possible for some generators to ‘free ride’ on the capacity that is built for (and paid for directly by) load. Indeed, the OFA package contemplates a mix of firm (that is, paid) and non-firm generators.

Not all generators would free-ride. Peaking generators that depend on access to the RRN at peak times would still have strong incentives to purchase firm access. However, some baseload generators that rely on average returns may have incentives to stay non-firm and operate on the planned network. As the AEMC (2012n, p. 87) note, given the presence of excess generation capacity, not all non‑firm generation would need to be accounted for in building the network to meet peak demand. This would make free riding on ‘reliability’ lines a somewhat risky proposition.[[17]](#footnote-17)

Another source of risk for non‑firm generators, even in areas of excess transmission capacity, would be the potential for entry by new generators. In uncongested areas, a new entrant could receive firm access for a relatively low price. A new, firm, entrant would not only reduce the non‑firm incumbent generator’s energy market returns in the short-term, but would also increase the cost of any future firm access that incumbent may wish to purchase (as that access would now require more immediate additional transmission investment, increasing the LRIC). To prevent this, the non‑firm incumbent would have an incentive to pre-emptively purchase firm access as a ‘defence’ against new firm entrants, further reducing the extent of free riding.

Nevertheless, while some free riding could erode the benefits of the OFA package, particularly in relation to generator location signals, it is unlikely to eliminate them. For instance, the benefits from addressing disorderly bidding would remain.

The degree of free riding also depends on the type of planning model that overlays on OFA. As noted in chapter 15, the adoption of the AEMC’s hybrid model would probably result in, on average, higher reliability standard than the NEM-wide probabilistic model advocated by the Commission. All other things equal, the hybrid model would result in more transmission investment for load purposes, and thus perhaps more free riding.

Further, a NEM-wide planner would be able to oversight firm access requests across the NEM, alleviating concerns of monopoly pricing, and reducing the reliance on regulation of TNSPs. At the least, an independent planner could be an additional source of information for generators, limiting the ability of TNSPs to price above cost.

Overall, the Commission considers that the benefits of the OFA package would still be significant even in the presence of transmission planning.

### The way forward

Disorderly bidding and the (lack of appropriate) long-term investment signals for generators contribute to congestion, affect the optimal use of interconnectors and planning for any future interconnector upgrades. If these issues were not resolved, the benefits from any further investment in interconnection would be muted at best, as generators have strategic incentives that can, under certain circumstances, frustrate the use of interconnectors. Accordingly, the Commission considers that reform is warranted.

The key to any solution is mechanisms that reveal the true cost (including congestion) of generators bidding into the NEM. Changes in the Rules that remove the current perverse bidding incentives of generators would better manage congestion and remove the current distortions that lead to underutilisation of interconnectors. Upgrading interconnectors would make little sense until these underlying incentives were addressed.

While short-term solutions such as the imposition of congestion management formulae on bidding would be beneficial, the Commission favours the OFA package option in the AEMC’s Second Interim Report of the Transmission Frameworks Review, because it creates better market signals for generator location and transmission investment. While conceptually complex, the information to implement it is already available and so its implementation should not face many practical obstacles. The implementation of OFA transfers rents from some generators, but that does not involve any inefficiency, and in any case, the existing system leads to transfers that are arguably less defensible.

Although it removes the incentive to disorderly bid, optional firm access implements new pricing arrangements, and could create new incentives for participants to ‘game’ the system in different ways. It would therefore be prudent to monitor generator bidding behaviour to observe if any new patterns emerged. This could inform any ‘fine tuning’ that the system may require at a later date.

DRAFT Recommendation 18.1

In the absence of any unintended consequences identified during current consultation processes, the Australian Energy Market Commission’s ‘optional firm access’ package for generator access to the transmission network should be implemented.

* It should operate for a period of at least 10 years.
* It should be monitored by the Australian Energy Market Operator for its effects on network planning and performance and, in concert with the Australian Energy Regulator, changes in observed patterns of generator bidding behaviour. Monitoring results should be made public annually.

While optional firm access appears to be beneficial, it is not necessarily the end‑point for market reform in the NEM. Over the longer-term, there may be grounds for more fundamental reform.

## 18.4 More fundamental reforms

### Nodal pricing — theory

Optional firm access is an effective way of resolving perverse incentives that arise in the presence of congestion, but it does so by using the existing regional settlement method and essentially ‘retro-fitting’ side compensation payments. A more direct method of managing congestion would be to dispatch and pay generators according to their locational marginal price (LMP), not a regional price. The price of electricity at different locations where electricity is injected or withdrawn from the network (‘nodes’) would differ (a model also referred to as ‘nodal pricing’), especially in the presence of congestion on particular lines.

In addition to exposing generators to the ‘true price’ (encompassing production, location and congestion costs) at their connection point, nodal markets also generally involve a system of ‘financial transmission rights’ (FTRs), that operate in a similar manner to optional firm access rights (typically defined on either a point-to-point, or ‘flowgate’ basis). In effect, FTRs provide access to the local price at the ‘destination’ node, acting as a form of hedge between nodes. Importantly, these rights can be purchased, typically at auction, on a ‘directional’ basis (that is, ‘A to B’ is a separate right from ‘B to A’). The rights can be purchased by both users and producers. In the same way as firm access rights, the auction of FTRs could provide a market-driven signal for transmission investment from *both* supply and demand sides of the electricity market, aligning transmission investment with its value to users.

Several electricity markets around the world use such nodal pricing, but the exact model applied varies between markets. For example, both the Pennsylvania-New Jersey-Maryland (‘PJM’) in the United States and the New Zealand electricity market use ‘full nodal pricing’, that is both generation and load are settled at nodal prices.[[18]](#footnote-18) Alternative models include ‘generator nodal pricing’ where generators are settled using granular locational based pricing, but loads are settled using more aggregate prices (for example, prices for a zone or region, or a single price for the entire system). One example of this is the New York electricity market in the United States, where generators are settled on a ‘location-based’ marginal price (similar to LMPs), and loads are settled on a zonal basis, using a load-weighted average of the prices within their zone (Frontier Economics 2009, p. 39).

While the increased granularity of nodal pricing encourages more efficient dispatch (by removing incentives for behaviour such as disorderly bidding), it can in turn facilitate other forms of inefficient behaviour. In nodal markets this typically manifests itself as more traditional uses of market power, with generators withholding supply in order to increase their LMP. This is one of the reasons why some nodal markets include measures designed to encourage levels of supply, while inhibiting the ability of generators to exercise market power. For example, the PJM market incorporates:

* an *offer cap* to prevent large spikes in prices. These are set at $1000 per MWh by the Federal Energy Regulatory Commission. (The presence of capacity markets in the United States is intended to provide a means for generators to recover fixed costs, while energy market returns recover variable costs. In contrast, in the Australian NEM, the high price cap in the energy market is intended to allow generators to recover both fixed and variable costs.)
* *market power mitigation rules* designed to prevent the use of local (or time-limited) market power. These rules entail capping of generators’ offers, typically applying a formula based on generator-specific cost-based schedules (Hogan 2012b). In some markets, the trigger for application of these rules has been refined over the years to concentrate on those generators and bids that would have a significant impact on the market (Frontier Economics 2009).

Despite the concerns of the structural presence of market power, there has been little evidence of the exercise of market power in the major nodal markets to date (Frontier Economics 2009, Rose 2011). This suggests that the combination of capacity markets and mitigation rules has had some effect in limiting the ability of suppliers to take advantage of their positions of market power.

Nodal pricing is the subject of significant academic and regulatory analysis — more detail on the theory of nodal pricing, and particularly its application in a variety of markets can be found in Frontier Economics (2009) and NWRED (2011), among other sources.

### Nodal pricing in Australia?

Nodal pricing in the NEM was proposed in a major review 10 years ago (Parer 2002). However, it has not been adopted due to its complexity, perceived difficulties in implementation and potential increases in risk in financial markets. Perceived political difficulties with exposing customers within the same region of the NEM to different energy prices have also been an obstacle. There have also been concerns that the ‘geography’ of the NEM is not as suited to nodal pricing as some other networks are. For example, PJM is a highly meshed network, and as such there is potential for congestion on a single line to have wide-reaching effects. In comparison, the NEM is a more ‘stringy’ (or radial) network where distance looms as a larger issue than congestion. While nodal pricing may have particular benefits for networks such as PJM, it would nonetheless provide benefits for the NEM, both in terms of dealing with congestion,[[19]](#footnote-19) and properly accounting for location.[[20]](#footnote-20)

In the First Interim Report of the TFR, the AEMC contemplated an option for a form of nodal pricing that included a single national price for customers (box 18.4).

However, the AEMC’s proposed option was not supported by stakeholders in that review who noted that, among other things, a single national price for load would blunt any efficiency gains by rendering the demand side unresponsive to any localised price signals (AEMC 2012j, p. 122). In the Second Interim Report, the AEMC decided against further consideration of the model. It stated that difficulties in creating the single TNSP (that it felt was a necessary component of the model), combined with the efficiency concerns of a single national price for load made the model a ‘disproportionate response’ (p. 123).

If full nodal pricing were to be implemented, the Commission acknowledges that differences in pricing between locations can cause equity concerns. But, as noted elsewhere in this report (chapters 11 and 14 and draft recommendation 11.6), the Commission considers that such concerns should be dealt with by more transparent and targeted assistance for particular customer groups, rather than uniform pricing. Doing so would alleviate distributional concerns, while preserving the efficiency gains available through (cost reflective) price signals. Providing information to consumers about the nature of the change, the benefits from it, and the options available to them would also be an important precursor to any implementation of nodal pricing. [[21]](#footnote-21)

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| Box 18.5 The AEMC’s National Locational Marginal Pricing |
| The First Interim Report of the Transmission Framework Review included the option of a ‘national locational marginal pricing’ (NLMP) package.  In this package, generators would be settled in the energy market using their locational marginal price (LMP). This component of the package would largely remove the incentive to disorderly bid, as generators would no longer be able to enter low bids yet receive the higher regional price.  Generators would then have the option of purchasing (at auction) fully firm financial transmission rights. These rights would provide firm access to a single, national trading hub. This hub would use a single ‘system marginal price’. Load (that is, users) would be settled at the system price, not using LMPs. This was intended to provide a deeper and more liquid energy trading market than the present regional system. More broadly, the package would remove the need for ‘regions’ in the market arrangements.  The AEMC envisaged the implementation of NLMP involving a single, national TNSP. This TNSP would initially auction the baseline transmission capacity, followed by auctions for incremental capacity. It would be exposed to incentives that encouraged the availability of the auctioned transmission capacity. This capacity would be made available by investing in the physical network to ensure that its capacity matched the amounts purchased at auction. |
| *Source*: AEMC (2011f). |
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The substantial difference between the current NEM model and nodal pricing has also raised concerns in the past about the degree of transition costs that could be incurred by moving to nodal pricing. Indeed, the introduction of nodal pricing would require careful establishment of new market infrastructure. This is a particular issue for the hedging markets, and one that must be considered alongside the auctioning of financial transmission rights (FTRs), a significant issue for the New Zealand market. The introduction of nodal pricing would also require consideration of governance issues, particularly if the markets’ departure from a regional structure lends further weight to NEM-wide transmission planning.

While transition costs are a relevant consideration for judgements of reform, there are several well-known ways to minimise them by managing the transition process — general options include the pre-announcement of changes, and gradual phasing in of reform. However, given it is a significant shift from the status quo, and a matter of market design, adopting nodal pricing may not be conducive to phasing.

While phasing directly to nodal pricing may not be appropriate, the Commission considers that the OFA package represents a substantial transitional step towards implementing nodal pricing. It involves many of the same (or at least analogous) aspects to nodal pricing — including the calculation of LMPs, a concept of congestion pricing and firm access rights. Thus, allowing the OFA package to operate for a period of 10 years would allow the energy market to acclimatise to many of the complexities that have frustrated the thought of implementing nodal pricing in the past. Similarly, it could also allow hedging markets to adjust to the concept of different prices (for generators).

After that time, a cost-benefit analysis of the introduction of nodal pricing should be conducted, with a view to identifying any significant and insurmountable obstacles that would prevent its adoption. Such an analysis could also consider the exact form of nodal pricing involved, the structure of financial transmission rights (particularly given the evolution of optional firm access requests) and any accompanying market infrastructure that would be required, such as capacity markets or the need for any specific market power controls. At this time, extensive community consultation would also be required.

draft Recommendation 18.2

After the optional firm access package has been operational for 10 years, a cost‑benefit analysis should be conducted, with particular regard to the structure of the National Electricity Market at the time, the views of consumers, and any remaining barriers to the introduction of nodal pricing.

* If the analysis finds net benefits are likely, and no significant and insurmountable barriers or risks are identified, nodal pricing (including financial transmission rights) should be introduced with appropriate transitional arrangements and arrangements for disadvantaged consumers.

## 18.5 The hedging market

Spot energy market prices in the NEM are highly volatile. This means that any market participant that traded directly through the spot market would be exposed to a significant level of pricing risk. Participants in the NEM manage this risk either by trading in the hedging market (described in appendix C), or through vertical integration with retailers (creating ‘gentailers’). Despite being a purely financial market, outcomes in the hedging market can affect actual energy flows, and particularly the level of interstate trade in electricity.

### Hedging markets are state-based

Participants in the hedging market enter contracts based on the NEM’s state based regional reference prices. This allows participants within a region to contract effectively because they are both exposed to the same spot market price. However, if a party wanted to contract with a party in another region of the NEM it would need to bear the risk associated with relative movements in the prices in different states, or alternatively, find a way to manage that risk (box 18.6).

One way to manage this risk is through Settlement Residue Auctions (box 18.7) that allocate inter-regional settlement residues (IRSRs). IRSRs are a financial product that distributes the price residues that occur when electricity is transmitted across a regulated interconnector. However, IRSR’s are a non-firm hedge, which means that if there is a large price separation between two regions and power does not flow through the interconnector, as can occur through disorderly bidding, there is no residue to distribute and the hedging strategy fails.

While it is difficult to know how IRSRs are used by market participants, Anderson et al. (2007, p. 30) suggest that IRSRs are used primarily as speculative instruments, rather than as hedging instruments — contrary to the original intentions of policy makers. (This view was also echoed in comments by participants in the Commission’s consultations.)

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| Box 18.6 Understanding the risk of trading between regions |
| A standard hedging product, known as a contract for difference, allows market participants to determine prices in advance and remove the exposure to the spot market. Under such a contract, the generator and the retailer agree to a ‘strike’ price (shown as X below), which will ultimately be the terms on which they trade, even if the spot price (P) is different.  If the pool price is lower than X (which would expose a generator to losses without hedging), the generator would receive P from the wholesale market and X-P from the retailer, with a net price paid for power of X. If the pool price was above X, the retailer would buy power at P on the wholesale market (that is, would have an apparent exposure of -P), but would receive P-X so that the actual exposure would be –X. The payoff structure is represented below:   |  |  |  |  | | --- | --- | --- | --- | |  | Spot market exposure | hedging contract | Net exposure | | Generator | P | X - P | X | | Retailer | -P | P – X | - X |   However, when trading between regions, the spot price exposures are no longer the same. So, if a retailer (in region 2) buys a hedging contract from a generator in region 1, the payoff becomes:   |  |  |  |  | | --- | --- | --- | --- | |  | Spot market exposure | hedging contract | Net exposure | | Generator | P1 | X – P1 | X | | Retailer | - P2 | P1 – X | - X + (P1 – P2) |   (P1 – P2) is the risk in relative movement in regional reference prices and is a natural risk of trading between regions of the NEM. |
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| Box 18.7 Settlement Residue Auctions (SRAs) |
| When electricity flows across a regulated interconnector, loads and generators are settled at their regional price. This means that if electricity flows from a low price region to a high price region (as would usually be expected), the price paid to generators will be less than the price paid by loads. The difference between the two prices, multiplied by the level of flow across the interconnector and after adjusting for transmission losses, is the inter-regional settlement residue.  AEMO sells these residues in a quarterly auction, and the winners of the auction receive the rights to a share of the interregional settlement residues in the upcoming period. |
| *Source*: AEMO (2011e). |
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The average payout of the SRA process corroborates this perspective. Were IRSRs used as a valuable hedging instrument, the auction revenues would be greater than the amounts paid out over the long term because buyers would be willing to pay a premium to manage risk.[[22]](#footnote-22) However, the evidence does not support this (table 18.1).

Table 18.1 Historical results of settlement residue auctions

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| --- | --- | --- | --- |
| Auction | Residue Distributed | Auction Proceeds | Payout rate |
|  | $ million | $ million | % |
| 2009 Q1 | 83.1 | 59.1 | 141 |
| 2009 Q2 | 83.0 | 15.6 | 531 |
| 2009 Q3 | 11.5 | 17.2 | 67 |
| 2009 Q4 | 145.7 | 28.0 | 520 |
| 2010 Q1 | 55.4 | 55.9 | 99 |
| 2010 Q2 | 13.9 | 16.3 | 85 |
| 2010 Q3 | 20.5 | 17.5 | 117 |
| 2010 Q4 | 18.3 | 32.1 | 57 |
| 2011 Q1 | 102.1 | 46.6 | 219 |
| 2011 Q2 | 6.6 | 17.6 | 37 |
| 2011 Q3 | 12.5 | 21.2 | 59 |
| 2011 Q4 | 16.4 | 29.2 | 56 |
| 2012 Q1 | 7.7 | 45.5 | 18 |
| Total | 576.7 | 401.8 | 144 |

*Source*: AEMO Auction Reports (AEMO website).

If firms do not use the IRSRs to manage the risk of trading electricity contracts across regional boundaries, they are left with two options. Either they trade across the border exposed to the interregional price separation risk, or they trade only within their state.[[23]](#footnote-23) Of these, the latter is more common, with retailers and generators trading derivative products with other market participants that operate in the same region of the NEM.

### Implications of a state-based hedge market

The inability for market participants to effectively trade between regions of the NEM, without being able to manage the risks well, may result in distorted incentives for new generators and large electricity consumers. It may also result in a lack of liquidity in parts of the NEM and may create market power.

#### Incentives for generator location

The difficulty of trading hedging contracts across regions could distort the locational decisions of new generators and energy consumers. When a generation business chooses a location for a new generator, a key concern will be the availability of well-priced hedges. This consideration will make them more likely to enter a region in which there is more consumption than generation of electricity. This incentive will be in addition to the interplay of supply and demand for electricity. For example, consider a generator that was planning to enter the NEM near the New South Wales–Victoria border. From an engineering perspective, it makes little difference which side of the border they are placed. However, the new generator will look at whether it can trade in forward markets at a higher price in New South Wales or Victoria. A similar situation would occur with large electricity consumers, such as smelters, although access to the hedging market would usually be a lower priority for the locational choices of these parties.

These problems in the hedging market have the potential to equalise the level of electricity generation and consumption in each region of the NEM, as each new generator will favour a location in a region with less generation than consumption, and each new load will favour a region that has more generation. This would result in less interconnector construction and usage than might be efficient. It would also make it more difficult for a state to act as a net producer of electricity in the NEM and reduce the benefits from efficient trade across the NEM.

The size of this impact is unclear. The different regions in the NEM are all relatively evenly matched between retail load and generation, which partly reflects history, but also suggests that the incentives described above could be strong. However, there are several other reasons that parties wish to build generation close to a load centre, such as avoiding transmission losses and ensuring a more reliable dispatch.

The Commission seeks participants’ views about the extent to which flaws in a state‑based hedging market distort the locational incentives of generators and large loads.

#### Less liquidity in the hedging market

Financial liquidity is measured as the amount of trade that occurs in a particular market. Liquidity is important in a market, as it gives market participants confidence that they will be able to enter and exit contracts in the future. This is particularly important for a new entrant retailer or generator that required some assurance that they would be able to enter hedging positions once they commenced operations.

Higher levels of liquidity also lower the difference between the buying and selling price (bid–ask spreads) of instruments. Bid–ask spreads are a cost of transacting in the market and lowering those spreads results in lower trading costs for market participants.

Some parties suggest that levels of liquidity in the electricity futures market are low, particularly in some regions of the NEM (D-Cypha Trade 2011). However, if the market for electricity hedging products were to become more national, this would allow people to trade across states, and create greater substitutability of contracts in different areas. This would increase the liquidity and improve the performance of the market.

#### Issues of market power

While generation and retailing are now regarded as workably competitive in most regions of the NEM, market power is not entirely absent in these parts of the electricity system. Market power could arise, for example, if there are barriers to entry for new generators posed by the large scale of cost-efficient generators and a requirement for high capacity utilisation (which may require the capacity to sell into several regional markets). Box 18.8 sets out some of the claimed forms and impacts of such market power.

Improving the performance of interconnectors and allowing more interstate competition, both in a physical sense and in the hedging market, would further limit the ability of market participants to exercise market power.

There are also grounds for action in one area of (possible) gentailer conduct to reduce market power — while also assisting the RIT-T process. On first appearance, a gentailer has little incentive to exercise market power because high prices at the wholesale level hurt the retail side of their business. However, knowing when a price spike will occur in advance in theory might allow a generator to hedge out of their retail position. Any retail competitors will not know in advance when this might happen and would have to remain hedged against the risk at all times. This might give the gentailer a competitive advantage in the retail sector. This type of behaviour is difficult to detect, as hedging positions are commercial-in-confidence, an issue that has been of some concern in the United States (AEMC 2010b).

Accordingly, there could be some merit, from a regulatory perspective, in providing these hedging positions to the regulator retrospectively, perhaps 12 months after the event, and on a confidential basis. This could allow better examination of market power issues. The regulator could also use the information to publish (aggregated) summary data where this might help potential new entrants evaluate the risks and returns from entry into the generation and retail sectors. This could also have the added benefit of helping market modellers (within either a national planner or TNSPs) understand the incentives behind generator bids, which in turn could improve the accuracy of the RIT-T process.

However, such an improvement in transparency would involve compliance costs on the businesses involved, and risks breaching genuinely confidential contracts. These costs would need to be weighed against the benefits of additional transparency before any transfer of information might be mandated.

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| Box 18.8 Market power in generation? |
| Residual market power in generation and gentailing could take several forms, although their importance is strongly contested by varying parties. The ACCC has scrutinised the privatisation of New South Wales generation assets (ACCC 2011), AGL’s purchase of a larger share of the Loy Yang power plant,[[24]](#footnote-24) and whether gentailers are offering power purchase agreements to renewable energy generators (Wroe 2012). The AEMC has also considered issues of market power with regard to rule change proposals. The most recent example of this is the Major Energy Users proposal to restrict the bidding of dominant generators to $300/MWh. However, in its draft determination, the AEMC (2012o p.49) found insufficient evidence of any problem.  A simple case of market power would occur if a generator had the ability to push up prices in the spot market by withholding supply, and thereby attract more revenue. This would benefit any unhedged generator and adversely affect any unhedged retailer. However, any such market power would likely to be transient, since higher prices would attract entry by competing generators, and empirical analysis by the AEMC has not identified a significant problem (AEMC 2012o, p. i).  A slightly more subtle case of market power would arise if a generator were able to artificially create greater price volatility by withholding some generation capacity, or by bidding into the market at a high price. This might increase spot prices on those occasions, but it could also have an impact on the market for some types of hedging instruments, such as price caps. If that generator had some advantages in selling these instruments,[[25]](#footnote-25) such as a gas or hydro plant, they would acquire a return that would not be shared by other generators.  Competition benefits, which are the benefits from reducing market power, are also considered in the transmission planning and RIT-T processes.  The exercise of any market power by generators may have several efficiency costs:   * inefficient merit order dispatch would occur if large low cost generators bidding high were dispatched after peaking generators * demand side responses may be used inefficiently as the cost of a demand response is typically high compared to the cost of generating energy * market power may limit the competitiveness of the retail market. Some consequences of this are found in chapter 12 * if market power results in high prices in a region where there is no shortage of supply, it may give incentives for new entrants where none are needed. |
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### Options for reform

A more national hedging market would allow for improved risk pooling, enable an efficient spread of generation and load across the NEM and more competition in the generation and retail sectors. The best way to achieve this is to improve the effectiveness of IRSRs.

The AEMC’s OFA package includes the option to purchase firm interregional transmission rights. These rights would replace the existing IRSRs and could be used to hedge across regions, with two additional advantages. The access rights would be firmer than under the existing arrangements, making them more likely to be valuable in a hedging portfolio.[[26]](#footnote-26) In addition, the OFA structure nullifies incentives for disorderly bidding, and this would also make the hedging instrument more valuable. The OFA model would link the sale of these transmission rights to the incentives to build new interconnector projects.

Another reform option would be to alter settlement residue auctions so that the hedging instrument would pay the difference in the state prices regardless of the actual flow across the interconnector, which is ideal for the parties wishing to hedge. The Parer Review (2002) and the Energy Reform Implementation Group (2007) both suggested variations of this option.

However, the success of this approach would need to overcome several issues:

* As electricity does not always flow between regions when there is a price difference, there may be insufficient revenue to pay parties that purchased the transmission rights. This would require drawing additional funding from elsewhere in the network.
* This approach would become complicated if the parties that can cause counter price flows along a transmission line near some congestion (such as generators near a state border) were also bidding into the auction.

The OFA is the superior option since it addresses many other issues apart from flaws in hedging arrangements. If OFA is not implemented, then there are grounds for amending settlement reside auctions as a second-best option.

1. Some other markets, such as the Pennsylvania-Jersey-Maryland (‘PJM’) and New York markets in the United States, use separate capacity markets to ensure the long-term adequacy of power supply within their markets (Frontier Economics 2009). Such markets can include not only generation capacity but also demand response and transmission investment. [↑](#footnote-ref-1)
2. Generators submit bids in a ‘schedule’ (supply Y1 MW at price P1, Y2 at price P2 and so on) in daily bids, submitted before 12.30 on the day before supply is needed. They may submit re-bids until five minutes before dispatch. Re-bids may change the volume, but not price of electricity offered (AEMO 2010f). Nonetheless, with a sufficiently large number of price bands within a schedule (and re-bidding volume in other bands to zero) re-bidding of volumes, in effect, amounts to price changes. [↑](#footnote-ref-2)
3. The spot price used to settle market transactions is calculated for a 30-minute trading interval as the average of the six dispatch prices during the preceding 30 minutes. [↑](#footnote-ref-3)
4. There are other forms of market structure. *Nodal* markets involve many ‘nodes’ — the physical location, or grouping of locations — where power is entered or withdrawn from the network. Under nodal pricing, generators (and in some cases, customers) are settled at the price of their local node, and multiple nodal prices apply in a single market. At the other end of the spectrum, a single price could be applied across an entire network. [↑](#footnote-ref-4)
5. The Commission notes that disorderly bidding is a rational (and legal) response to incentives created through peculiarities of market structure. It uses the term in an analytical, not pejorative, sense. [↑](#footnote-ref-5)
6. Such clamping is not always successful, primarily due to generators’ stipulated ‘rates of change’ which affect how quickly a generator’s output can be forced down (or up) and thus allow periods of time where interconnector flows can only be gradually, not instantly, reduced. [↑](#footnote-ref-6)
7. Of course, generators maximising their return in the presence of temporary congestion is not a phenomenon unique to the NEM. In other markets, exercising transient market power can manifest in different ways, for example, there is some evidence of generators withholding supply at times of import congestion in Norway (Mirza and Bergland 2012). [↑](#footnote-ref-7)
8. As noted in chapter 17, a Frontier Economics study conducted for the AEMC’s Congestion Management Review (AEMC 2008b) concluded that the (modelled) production costs due to disorderly bidding were only $8 million higher than the base (normal) case. Given production costs in the NEM at the time were $1.7 billion, this equated to a 0.47 per cent increase in costs. [↑](#footnote-ref-8)
9. As noted in chapter 3, various state governments still have significant common ownership of generation and networks. There is no evidence that they have taken advantage of this. [↑](#footnote-ref-9)
10. For example, package 2 of the AEMC’s First Interim Transmission Framework Review divides generators’ returns into two components: energy payments settled at the marginal price at their local node, and a hedging element that divides the total *intra*-regional settlement residue between generators according to capacity, not dispatch. [↑](#footnote-ref-10)
11. These five packages were: a minor clarification to the status quo, a ‘shared access congestion pricing’ mechanism that would effectively impose congestion pricing at times of constraint, introducing transmission reliability standards for generators, an option to allow generators to purchase ‘firm’ access along transmission lines, and locational marginal pricing for generators (but not load). [↑](#footnote-ref-11)
12. For the purposes of implementing the OFA package, the AEMC examined specific pricing methods. They defined LRIC and LRMC as different methods. In the technical appendix to the Second Interim Report of the TFR (AEMC 2012n, pp. 42–43) the AEMC discussed the relationship between their definitions of the two measures (as well as ‘deep connection charging’). [↑](#footnote-ref-12)
13. In particular, the settlement mechanism has a similar effect to the ‘Shared Access Congestion Pricing model (‘package 2’ from the TFR First Interim Report). [↑](#footnote-ref-13)
14. That is, the difference between a generator’s ‘entitlement’ (or access right) and their ‘use’ (or quantity dispatched). [↑](#footnote-ref-14)
15. A ‘flowgate’ is a location on the shared network where congestion can occur (effectively, a transmission line between nodes). When congestion arises, these lines become bottlenecks in the transmission network. The AEMC (2012n, p. 99) define flowgate capacity as a combination of transmission line capacity and local demand (to the extent that it participates on a given flowgate). [↑](#footnote-ref-15)
16. To the extent that the generation market is not fully competitive, there is also the possibility of the reverse case — that is, generators passing on, at least partially, the costs to energy users through increased wholesale prices. Where this constitutes a misuse of market power, it is a matter of competition regulation, which to date has found it difficult to detect and prove such offences. Nonetheless, the congestion management aspects of the proposed OFA model should at least cut off disorderly bidding as one avenue for using market power. [↑](#footnote-ref-16)
17. The AEMC (2012n, p. 87) also note that, given TNSPs should meet reliability requirements with least-cost builds, they are likely to build (or augment) lines to generators close to the RRN. This makes generators remote from the RRN much less likely to free ride than those close to it. [↑](#footnote-ref-17)
18. But these markets differ in other respects. For example, in the PJM market, ‘point-to-point’ FTRs were introduced when the market commenced (Frontier Economics 2009). In New Zealand, the market commenced in 1996 and FTRs have been the subject of much debate and analysis since then, without being implemented. Following a more recent consultation process, the New Zealand Electricity Authority (2012) expects the first auction of inter-island FTRs to be in early May 2013. [↑](#footnote-ref-18)
19. As noted in chapter 17, and above, while congestion is not (currently) prevalent in the NEM, instances of congestion can lead to substantial transfers, and have long-term efficiency effects. [↑](#footnote-ref-19)
20. As discussed above in relation to the OFA package, it is important that location (including the costs related to distance and the requisite network investment) is considered as part of an overall investment decision for load and generation. In many cases, it may not change the final decision, as proximity to load or resources will often be the deciding factors, but it is nonetheless important that it is included in considerations. [↑](#footnote-ref-20)
21. The options to consumers would arise through retailers, who could increase their range of tariff offerings by purchasing different bundles of FTRs. This could also allow different retailers to ‘specialise’ in different types of ‘package’ such as flat (sourced through FTRs that ensured financial access to baseload generators) or variable (FTRs to a range of generators) pricing. [↑](#footnote-ref-21)
22. A point made by AEMO (sub. 32, p. 26). [↑](#footnote-ref-22)
23. There is a third option where a firm can hedge using an interregional swap. This involves purchasing a short position in one region and a long position in another, and creates a ‘firm’ hedge. However, using this as part of a trading strategy across regions is effectively just hedging each individual trade in each region. [↑](#footnote-ref-23)
24. *Australian Gas Light Company v Australian Competition & Consumer Commission (No 3)* [2003] FCA 1525 [↑](#footnote-ref-24)
25. A discussion of the types of hedging contracts that different generators tend to trade can be found in appendix C. [↑](#footnote-ref-25)
26. Though firmer than the current IRSRs, the inter-regional rights under the OFA package are not fully firm, as they would be ‘shaped back’ (proportionately scaled down) under certain circumstances. [↑](#footnote-ref-26)