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21 August 2013

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

Dear Mr Pierce

Request for Rule Change – Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities

As you are aware, the AER has been very active in the debate surrounding the implications of congestion-related disorderly bidding. Indeed, the AER made several submissions to the Australian Energy Market Commission's (AEMC) Transmission Frameworks Review (TFR). In addition, in December 2012 the AER published a Special Report entitled *The impact of congestion on bidding and inter-regional trade in the NEM* (attached) and in March 2013 the AER made a submission to the Productivity Commission's *Electricity Network Regulatory Frameworks Review* entitled *Possible options for interim solutions to congestion-related disorderly bidding* (attached).

Disorderly bidding is bidding by generators in a non-cost reflective manner, typically in response to transmission congestion. For example, if the market price is high, but congestion means certain generators have to generate less, those generators have an incentive to find ways to keep generating. They might bid in at prices well below their costs or restrict the speed at which the output of their plant can be lowered.

Over the last three years in particular the increasing prevalence of disorderly bidding has led to inefficient dispatch and created unnecessary price volatility which is impossible to predict. This unnecessarily increases the wholesale spot market price risk faced by retailers and generators. The higher risk profile is a cost which ultimately flows through to consumers through higher energy charges.

The AER also considers that disorderly bidding greatly reduces the effectiveness of interconnectors, making it more difficult for retailers and generators to hedge across region boundaries. This lowers the competitiveness of the wholesale market with longer-term flow-on effects to efficiency and prices.

In addition, there is a clear productive efficiency loss from disorderly bidding through high-cost generation being dispatched in place of low-cost generation. This loss is most obvious in situations where disorderly bidding leads to counter-price flows on interconnectors (i.e. electricity flows from a high-price region into a low-price region), and consumers in the low-price region have to fund the shortfall.

The TFR Final Report recommended the Optional Firm Access (OFA) Model as a longer term solution to managing congestion in the National Electricity Market (NEM). The AER is supportive of further consideration of this approach. However, it is widely acknowledged that implementing the OFA Model represents a significant body of work and would take several years to implement. Given the seriousness of the disorderly bidding problem and the high costs for consumers, we consider an interim "partial fix" is required earlier.

We are proposing a rule change which would require generators to submit ramp rates (at all times) that reflect the maximum the generator is safely capable of achieving. This rule change proposal would apply equally to scheduled and semi scheduled generators, scheduled network services and scheduled loads.

As a related matter, this rule change proposal also seeks to ensure that when a fast start inflexibility profile (FSIP) is submitted, it is reflective of actual plant limitations at the time.

We consider that the rule change will ensure that there is alignment between the treatment of ramp rates/FSIP, and the treatment of frequency control ancillary services parameters and inflexible declarations. The current rules are clear that frequency control ancillary service parameters must reflect the technical parameters of the plant and that generators can only declare their plant inflexible based on technical limitations. Our rule change seeks to make the rules consistent with respect to the remaining technical parameters of a bid.

At times, generators have used ramp rates and FSIPs to achieve commercial outcomes. In particular, if a generator is required to be constrained off by the Australian Energy Market Operator (AEMO) due to network constraints during a period of high prices, the generator is incentivised to bid its ramp rate down to very low levels to minimise the extent to which it is constrained off. This leads to inefficiencies in dispatch and fluctuations in price. This Rule change proposal will demonstrate that the use of ramp rates to achieve commercial outcomes is not transient behaviour, but commonplace. Requiring generators to bid in their maximum safe ramp rate will significantly address the issue.

We consider that the rule change will also improve the security of the NEM when there is network congestion, as AEMO will be able to move the output of generators at a faster rate to address network constraints. AEMO will not breach a generator's technical parameters (which includes ramp rates and FSIPs) as it does not have any other information about a plant's capability. Indeed, AEMO may violate some network constraints before it breaches a plant's technical parameters. Therefore, having technical parameters that are the maximum a generator can safely attain will assist AEMO to maintain security.

It is important to note that the AER is supportive of market participants achieving their commercial objectives. However, the use of technical parameters to achieve commercial objectives can be harmful both in terms of inefficient market outcomes and the ability for AEMO to manage system security in an optimal fashion. To this end, this rule change proposal seeks to clarify the distinction between the technical and commercial parameters of bids.

Requiring participants to submit a ramp rate at all times that reflects their maximum safe capability is an extension of the AEMC's 2009 rule change (in response to a rule change proposal by the AER) which saw the minimum ramp rate increase from 1 MW/min to 3 MW/min or the technical maximum if that is less. Given the concerns with network congestion and associated disorderly bidding, the AER considers it appropriate to make ramp rates a technical parameter at all times.

We appreciate that given the very technical nature of ramp ramps, concerns may be raised with respect to how such a change may be enforced. To this end, the rule change proposal recommends that the AER revise its *Rebidding and Technical Parameters Guideline*, through the formal consultation process, outlining how such a requirement would operate in practice. This is discussed in more detail in the body of this rule change proposal.

Should you have any queries in relation to this matter, please don't hesitate to contact Tom Leuner, General Manager, Wholesale Markets, on 03 9290 1890.

Yours sincerely

Andrew Reeves
Chair

National Electricity Rules

Proposal to change clause 3.8.3A (Ramp rate) and clause 3.8.19 (Dispatch inflexibilities).

A Name and address of person making the request

Australian Energy Regulator
Level 35
360 Elizabeth St
MELBOURNE VIC 3000

B Description of proposed rule

This proposal relates to clauses 3.8.3A (Ramp rates) and 3.8.19 (Dispatch inflexibilities) of the National Electricity Rules (rules).

The AER considers that incentives for disorderly bidding are a significant problem with the current NEM design. This Rule change proposal proposes a partial solution to mitigate the most egregious cases of disorderly bidding. The AER considers this can be achieved by requiring scheduled network services, scheduled loads and scheduled and semi-scheduled generating units to provide a technical ramp rate at all times. Essentially this means requiring the relevant participant to submit a ramp rate that is the maximum the plant can safely attain at the time. This would put beyond doubt the status of ramp rates as technical parameters of a bid.

The AER also considers that in some circumstances fast start generators can use their dispatch inflexibility profile (more commonly referred to as fast start inflexibility profile or FSIP) to achieve commercial outcomes. Although not explicitly stated in the rules, as with ramp rates, a fast start unit's FSIP is considered to be a technical parameter of a bid and therefore not to be used for commercial purposes. To ensure the rules reflect this, this rule change proposal seeks to make it a requirement that fast start generators submitting an FSIP must ensure that the FSIP reflects the technical limitations of their plant at the time.

As previously mentioned, the AER considers ramp rates and FSIPs to be technical characteristics of a bid; therefore it is appropriate to address the perceived anomalies in the rules in relation to both as one rule change proposal package.

Ramp rates

Clause 3.8.3A relates to ramp rates, the rate at which the output of a generating unit may be varied up or down. The clause provides that participants must provide an up ramp rate and a down ramp rate to AEMO that is at most the relevant maximum ramp rate provided in accordance with clause 3.13.3(b)[1] and at least:

- 3MW/min in the case of a scheduled network service or scheduled load, or

[1] Clause 3.13.3(b) is a civil penalty provision and provides that "All *Scheduled Generators, Semi-Scheduled Generators* and *Market Participants* must provide *AEMO* with the *bid and offer validation data* relevant to their *scheduled loads, scheduled network services* and *generating units* in accordance with schedule 3.1".

- the lower of 3MW/min or 3 per cent of the unit’s maximum generation in the case of a scheduled or semi-scheduled generating unit,

unless there is a technical limitation preventing this.

This rule change proposal seeks to require relevant participants to submit a ramp rate that reflects the maximum safe capability at all times. The focus of the ramp rate component of this rule change proposal is on the bidding and rebidding of ramp rates by generators. However, for the sake of consistency, the rule changes are proposed to cover all participants to whom obligations regarding ramp rates apply.

The proposed revised drafting of clause 3.8.3A is contained in Appendix D.

Dispatch inflexibility profile

A slow start generator is defined in the rules as being a generator that is unable to synchronise and reach minimum loading within 30 minutes. In contrast, those generators that can satisfy these requirements, by default, are referred to as fast start plant. The rules provide a mechanism for fast start plant to inform the dispatch process of minimum start and stop times, and of capacity inflexibilities. This mechanism is known as the FSIP and is contained in Clause 3.8.19(e) of the rules.

This rule change proposal seeks to make it a requirement that those generators submitting an FSIP must ensure that the FSIP reflects the technical limitations of their plant at the time.

The proposed revised drafting of clause 3.8.19 is contained in Appendix D.

C Statement of Issues

Background

On 21 April 2008, the AER submitted a rule change proposal relating to the ability of relevant scheduled generators and market participants to bid and rebid technical parameters, including ramp rates, market ancillary service offers, and dispatch inflexibility profiles, in pursuit of commercial objectives when power system security could be compromised.

The proposal was precipitated by an AER investigation into the events of 31 October 2005. On that day, the National Electricity Market Management Company (NEMMCO), now AEMO, invoked network constraints to manage the impact of a transmission outage, which had the effect of constraining the dispatch of some generation in the vicinity. The AER found that some generators took action to minimise the commercial impact of these constraints by rebidding their ramp rates to very low levels. This limited the rate that NEMMCO was able to reduce the dispatch levels of those generators, thus hindering NEMMCO’s ability to effectively manage power system security during that event.

In 2009, the AEMC made a rule (*Ramp Rates, Market Ancillary Services Offers, and Dispatch Inflexibiliti*es, No.1 2009) which in effect separated the commercial parameters of an offer or bid (price and availability, which are both required to be rebid in “good faith”) from the technical parameters (ramp rate, dispatch inflexibilities and frequency control ancillary services trapezia).

The resulting rule change moved towards aligning the way in which these parameters were treated in the dispatch arrangements. It made clear that generators can use the commercial parameters of a bid for commercial purposes (i.e. reaching their desired output), but the NEM dispatch engine (NEMDE) will override them if required (i.e. by backing off low priced plant out of merit order in response to congestion). On the other hand, the technical parameters (including ramp rates) are required to ensure the safe operation of plant can be maintained. In support of this, NEMDE will not breach technical parameters under almost any circumstances. The distinction between technical and commercial parameters of an offer or bid is discussed further under the section *Technical versus commercial parameters of a bid*.

Problems associated with disorderly bidding

The way network congestion is managed was examined in detail by the AEMC in the TFR. Scarce transmission capacity in a given region can limit the ability of some generators to sell their energy at the regional wholesale price. During times of congestion, generators have an incentive to offer their electricity in a non-cost reflective manner (so-called “disorderly bidding”), which may lead to the dispatch of higher priced generation.

Over the last three years in particular, the increasing prevalence of disorderly bidding has created unnecessary price volatility, led to inefficient dispatch and created counter price flows across interconnectors. As a result the ability for market participants to manage risk across interconnectors has reduced and with it competition between regions. This has been most prevalent between Queensland, New South Wales and Victoria.

Network constraints can occur anywhere in the NEM and accordingly any interconnector, not just QNI and VIC-NSW, is at risk of counter price flows precipitated by disorderly bidding. All regions have been impacted by disorderly bidding in the past. [2]

The AER considers that incentives for disorderly bidding are a significant problem with the current NEM design. While the AEMC’s TFR Final Report proposed solutions to manage network congestion, those solutions, if implemented, would take many years to come into effect. This Rule change proposal does not represent a holistic solution to manage network congestion. Instead, it proposes a partial, easier to implement solution to help mitigate the most egregious cases of congestion-related disorderly bidding.

[2] Disorderly bidding by the Basslink Market Network Service Provider interconnector has led to it gaining an advantage over Victorian generators, which is the subject of a rule change currently under consideration by the Australian Energy Market Commission *“Negative offers from scheduled network service providers”*. Imports into South Australia can reduce following low priced bidding by South Australian generators located close to Victorian border.

What is disorderly bidding?

Network constraint equations are used in NEMDE together with generator bids to determine the optimal economic dispatch of generators to meet customer demand, subject to ensuring the system is secure.[3]

Generators that are forecast to be constrained have an incentive to rebid their capacity in order to limit the impact of a binding constraint on their dispatch. Generators with a negative coefficient in the constraint equation can rebid capacity into higher price bands and/or as unavailable to reduce the possibility (or the magnitude) of an increase in output as a result of being constrained-on. Generators with a positive coefficient in the constraint equation can rebid capacity into negative price bands to reduce the extent to which their dispatch levels will be decreased.[4] As NEMDE seeks the optimal way to manage the constraint (based on generator offer prices as a proxy for cost), rebidding capacity in this way will influence NEMDE's outputs, including generator dispatch levels, interconnector flows and regional prices.

Generators can also rebid to change their technical parameters such as ramp rates to limit the rate and extent to which their existing output levels can be decreased or increased. Generators with a negative coefficient can rebid to reduce the 'ramp up' rate to reduce the possibility (or the magnitude) of an increase in output as a result of being constrained-on. Generators with a positive coefficient can rebid to reduce the 'ramp down' rate to reduce the extent to which their dispatch levels would be decreased. When generators rebid their ramp rate, NEMDE may have to constrain other generators or interconnectors in order to satisfy the constraint.

This type of bidding, when the network is constrained, is referred to as 'disorderly bidding'. By engaging in disorderly bidding, generators are seeking to influence what outcomes NEMDE will choose to manage the constraint.

Impacts of disorderly bidding on generators and price

Disorderly bidding can increase price volatility in a region. When a constraint binds, regional prices can increase rapidly as NEMDE dispatches higher cost generation at their ramp rates to satisfy the constraint. Disorderly bidding can then initially lead to spot prices significantly higher than forecast, with offers further up the supply curve dispatched because of low ramp rates for lower priced offers and some peaking generators having insufficient time to react to ensure they are dispatched. The price can then fall significantly once the constraint no longer binds or lower priced offers with lower ramp rates are able to be utilised.

Impacts of disorderly bidding on interconnector flows

Disorderly bidding can also cause counter-price flows on interconnectors. According to the NEM design, in the normal course of events electricity will flow from low priced regions across interconnectors into higher price regions. However, when electricity is exported from a high price region into a lower priced region in order to manage congestion, counter-price

[3] A detailed explanation of how constraints operate is contained in the AER's *Special Report – The impact of congestion on bidding and inter-regional trade in the NEM* (attached), an excerpt of which appears in Appendix C of this document.

[4] If a constrained-on generator is bid unavailable AEMO can direct the generator on to assist with managing security. This occurs rarely, but in this case the directed generator is compensated based on costs incurred.

flows occur. Under these conditions, NEMDE determines that the optimal outcome to manage congestion in one region is to force the flow of electricity into an adjoining region. This outcome is exacerbated by the fact that interconnectors are effectively not limited by ramp rates, which allows for the flow of electricity over interconnectors to be changed very quickly.[5]

The most egregious examples of counter-price flows on an interconnector when the regional price differentials and flows are large are caused by disorderly bidding by generators close to an interconnector, when congestion arises between that generator and the regional reference node (RRN).

The AEMC is currently undertaking a review into the management of negative inter-regional settlements residues, and published an issues paper in April 2013.[6] In its submission to the issues paper, AEMO stated that the vast majority of negative settlement residue events result from constrained generators bidding at the market floor price, causing a spill-over across interconnectors.[7]

Inter-regional settlement residues

Inter-regional settlement residues occur when the prices between regions separate. Generators in the exporting region are paid at their regional spot price while retailers in the importing region pay the spot price in their region. The difference between the price paid in the importing region (by retailers) and the price received in the exporting region (by generators), multiplied by the amount of flow across the interconnector, is called a settlement residue. The rights to these residues are auctioned by AEMO in settlement residue auctions (SRAs).

When a counter-price flow occurs, however, AEMO has paid out more money to the generators in the exporting region than it has received from customers/retailers in both the exporting and importing regions. This is known as negative inter-regional settlement residue. The cost of funding these negative residues falls on the relevant transmission network service provider (TNSP) in the importing region. In turn, the TNSP recovers this expense through higher network service fees, which are paid by customers.[8]

Tables A1 and A2 in Appendix B detail 23 occasions where disorderly bidding at the time of network congestion has led to significant counter-price flows between Victoria and New South Wales since December 2009. Collectively these events led to almost $35 million in negative settlement residues. Table A3 lists each event where congestion in the Gladstone region and disorderly bidding led to more than $150 000 in negative settlement residues in New South Wales. In total these events led to more than $14 million in negative settlement residues.

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[5] The rate of change for the interconnector is limited only by the aggregate ramp rate of all generators on the other side of the interconnector.

[6] AEMC 2013, *Issues Paper, Management of negative inter-regional settlements residues*, 18 April 2013, Sydney.

[7] AEMO 2013, *Comments on Issues Paper, Management of negative inter-regional settlements residues*, p3, 31 May 2013, Melbourne

[8] The proceeds of SRAs are paid to TNSPs, which then reduces the transmission use of system (TUOS) payments charged to the TNSP's customers. Negative settlement residues reduce the SRA proceeds that otherwise offset TUOS payments.

Interconnector flows and SRAs

The effective operation of interconnectors plays a significant role in facilitating interregional trade and competition, to the benefit of market participants and end users of electricity.

Counter-price flows, however, decrease the value of holding SRA units.[9] One of the reasons that market participants purchase SRA units is to facilitate inter-regional hedging. Inter-regional hedging facilitates competition between generators in different regions and is efficiency enhancing as customers/retailers can hedge for a lower cost, brought about by competition. Inter-regional hedging occurs when a party enters into a hedge contract with a counterparty located in another region of the NEM. The terms of hedge contracts are usually struck with reference to the spot price of a specified region. The counterparty that is located in a different region (i.e. not the "spot price" region) of the NEM is exposed to the risk of price separation between the regions. When significant divergence occurs, that counter-party is subject to financial loss. Purchasing a sufficient amount of SRA units to match the hedge contract quantity and capture the price difference between regions is one way to mitigate that risk.

When the flows over an interconnector from a low price region into a high price region are constrained due to disorderly bidding, the amount of inter-regional settlement residues that accrue (the price difference multiplied by the flow of energy) is reduced. As settlement residues are divided equally amongst SRA unit holders, this means that unit holders receive a lower than expected return for the price difference between the two regions for the relevant trading intervals. When counter-price flows occur, the value to SRA unit holders is zero.[10]

The impact of disorderly bidding on interconnector flows and settlement residues greatly reduces the value of SRA units and makes SRA units a less firm method of managing risks associated with inter-regional contracting.

Technical versus commercial parameters

The parameters a participant submits as part of its offer are designed to reflect its commercial objectives. Certain elements, however, are required by the rules to reflect the technical characteristics of the plant such as those related to ancillary service parameters or when a generator declares itself inflexible and is unable to follow dispatch instructions.

The rules are currently silent on other technical elements submitted, such as ramp rates (except when these rates are very low) and circumstances where a generator decides to commit its generator using the fast start inflexibility provisions (FSIP). This is despite the dispatch process treating these parameters as if they do reflect the technical characteristics of plant.

[9] Inter-regional settlement residues are allocated to holders of SRA units on a pro rata basis. If a participant has purchased 100 MW of SRAs out of a possible 500 then it would receive one-fifth of the inter-regional settlement residues that accrue on that interconnector for every trading interval (provided the residue is positive). SRAs are sold for each quarter of the year.

[10] If counter-price flows occur, then negative inter-regional settlement residues will accrue. Under rule changes which commenced in July 2010, the TNSP in the importing region is responsible for funding negative inter-regional settlement residues. The settlement residues returned to SRA unit holders under these conditions is zero.

The purpose of this rule change is to align all of the rules related to technical parameters to ensure they at all times they reflect the true characteristics of plant and cannot be manipulated for short term commercial gain in the spot market .

Figure 1 shows how NEMDE prioritises the constraint violation penalties (CVP) associated with various selected constraints. CVPs (expressed as a multiple of the price cap) represent the incremental cost incurred if a constraint equation is violated. Higher CVPs are associated with higher priority constraint types. NEMDE prioritises the order for relaxing constraints that cannot be simultaneously satisfied.

Figure 1: Constraints and Constraint Violation Penalties

Constraint type	**CVP**	**Comment**
Ramp rate	1155	NEMDE takes as given as it cannot second guess generator capability
FSIP (T1, T2, T3, T4)	1130	NEMDE cannot second guess generator capability
Minimum and fixed loading level	380	NEMDE cannot second guess generator capability
Satisfactory network limit	360	Beyond this may damage equipment
Secure network limit	35	Beyond this may damage equipment following a credible contingency

Figure 1 highlights that ramp rates and dispatch inflexibility profiles are considered high priority constraints (indeed, ramp rates are the highest order constraint). This is because AEMO is dependent on what generators submit. The importance of these constraints is evidenced by the fact that ramp rate and FSIP constraints have higher CVPs than satisfactory and secure network limits.

The AER considers this conflict in the role of ramp rates and FSIPs must be resolved. Arguably, requiring generators to limit their ramp rate bids and rebids and FSIPs to levels that correspond to the actual physical or technical capability of their plant, is just a refinement to meet the original intent of the 2008 rule change and would make the treatment of these parameters in the rules consistent with the inflexibility requirements of 3.8.19(a) and frequency control ancillary service offers in 3.8.7A. The AER considers that, if made, this rule change proposal would further enhance system security and significantly reduce the impact of disorderly bidding.

Ramp Rates

<u>Current Rules</u>

Clause 3.8.6(a)(2)(iii) requires a scheduled generator’s dispatch offer to specify for each of the trading intervals in a trading day, an up ramp rate and a down ramp rate. This enables AEMO to issue dispatch instructions to generators to vary their output to match supply and demand consistent with the offer. Participants have the ability to rebid their ramp rates during a dispatch interval with effect from the next dispatch interval.

Under clause 3.8.3A generators must specify a ramp rate that is 3MW/min or higher (or 3 per cent for generators below 100 MW in capacity) unless there is a technical limitation on their plant.[11] For most generators this requirement is towards the lower end of its technical capability. Generators must provide a reason to AEMO electronically whenever a rebid is submitted. In the event the ramp rate is less than 3MW/min, the reason must reflect the technical reason why a higher ramp rate cannot be achieved. AEMO publishes the reasons submitted by participants and the AER monitors them.

The 3 MW/min minimum requirement followed a proposal from the AER in 2008 to amend the relevant clauses of the rules (the rule became effective from January 2009).[12] Prior to this rule change, generators were able to offer or rebid ramp rates as low as 1 MW/min. The level of 3 MW/min was chosen as a pragmatic compromise between the maximum technically possible and ensuring enough ramping capability was available to AEMO to manage system security.

Example of the implications of the current Rules

Snowy Hydro's Tumut facility is registered as a single aggregated unit (despite being made up of 6 generation units) and has a maximum capacity of 1800 MW.

Most of the time, Tumut's ramp down rate is in the order of 30 MW/min. However, its offer is often 200 MW/min. This means it can ramp down from maximum output to zero in less than 10 minutes. However, if it reoffers its ramp rate to 3 MW/min, the current minimum allowed, (e.g. for commercial reasons such as when prices are high and a constraint is binding that is trying to force Tumut to lower output levels), it would take 10 hours to ramp down to zero output. The AER considers this demonstrates how generators can use ramp rates (a technical parameter) to their commercial advantage.

The use of ramp rates for commercial rather than technical reasons is a systemic, long-standing issue. The AER has written of many instances (in Spot prices above $5000/MWh reports and Weekly Market Analysis reports[13]) where ramp rates have been used for commercial reasons rather than technical reasons. Several of these examples are included in the following.

Spot price events above $5000/MWh in New South Wales, 2009 and 2010

Congestion in New South Wales in late 2009 and into mid 2010 (primarily associated with the repeated binding of the N>>N-NIL_S constraint) saw the spot price in New South Wales exceed $5000/MWh on 7 and 17 December 2009, 4 and 22 February 2010 and 10 August 2010.[14] On several of these days the spot price exceeded $5000/MWh for several

[11] For simplicity, whenever the minimum ramp rate is stated it should be read as 3MW/min or 3 per cent for generators below 100 MW in capacity.
[12] AEMC 2009, *Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility*, Rule Determination, 15 January 2009, Sydney.
[13] In accordance with clause 3.13.7 of the rules, the AER is required to monitor and report on significant variations between forecast and actual prices. The AER provides this in its weekly electricity reports including detailed analysis when the spot price exceeds three times the weekly average in a region and $250/MWh or is less than -$100/MWh. In addition the AER is required to publish a report when the spot price in a region exceeds $5000/MWh.
[14] This constraint managed flows across one of the Mt Piper to Wallerawang 330 kV lines in the event of the loss of the second Mt Piper to Wallerawang line.

trading intervals.[15] Common to each day was the use of ramp rates by generators for commercial reasons, which amplified the market impact of the congestion.

Rebidding of down ramp rates by Delta Electricity (from 5 MW/min) to the minimum allowable of 3 MW/min at its Mt Piper units and a reduction in available capacity at its Wallerawang units significantly contributed to the high price events in December and February.[16] On three of the four days they also shifted substantial capacity into high price bands.

Given their close proximity to the relevant network elements, the Mount Piper and Wallerawang units' coefficients on the constraint were much greater than for other generators or interconnectors.[17] By reducing the ramp down rate to a low value, the ability for NEMDE to 'constrain-off' these generators is limited. As a result, to manage flows on the network other generators and interconnectors needed to be constrained, but by a larger amount. This saw large quantities of low-priced generation constrained off and limitations on the interconnectors, thus limiting imports into New South Wales.

At the same time as it reduced the ramp down rates on its Mt Piper units, Delta Electricity increased its ramp up rate from 5 MW/min to 10 MW/min. Increasing its ramp up rate meant that when the constraint ceased binding (it was not binding continuously) NEMDE would ramp the generator up again at a faster rate only to then ramp it down at a slower rate when it bound again. On 7 and 17 December and 4 February the rebid reasons relating to the change in ramp rates related to constraint management. On 4 February, the rebid reason related to the trip of another unit in its portfolio. In other words, the rebid reasons reflected commercial considerations, not technical plant reasons.

The rebidding by Delta Electricity exacerbated the already tight supply conditions. For example, import capability from Victoria and Queensland on 7 December was up to 2200 MW lower than forecast 12 hours ahead and about 600 MW of low-priced New South Wales generation was constrained off. On 7 December around $586 000 of negative settlement residues accrued, $356 000 of which accrued across the New South Wales to Queensland interconnector (into Queensland) and around $230 000 was accrued across the Victoria to New South Wales interconnector (into Victoria).

Other generators also rebid their ramp rates opportunistically for commercial reasons to take advantage of the tight market conditions in New South Wales on these days. For example, on 7 December and 4 February, Macquarie Generation rebid the ramp down rates of its Bayswater and Liddell units from 5 MW/min and 4MW/min respectively to the minimum allowable of 3 MW/min to reduce the impact of the constraint on its dispatch. At the same time it increased its ramp rate up rate from 4 MW/min to 6 MW/min and 12 MW/min respectively. The reason given for these change in ramp rates related to constraint management.

The largest change in ramp rates for commercial reasons during this period was by Snowy Hydro at Tumut Three on 4 February. To prevent being constrained off, Snowy Hydro rebid

[15] The relevant *Spot prices above $5000/MWh* reports can be found by clicking here.

[16] In 2011 the New South Wales Government sold the electricity trading rights of some state owned power stations. Energy Australia has the trading rights for Mt Piper and Wallerawang power stations.

[17] The effects of these coefficients have been written about in detail in the relevant *Spot prices above $5000/MWh* reports, which can be found by selecting the "$5000 report" category here.

its ramp rate from 200 MW/min to the minimum allowable of 3 MW/min. Snowy undertook similar behaviour on 10 August 2010 when the spot price in New South Wales exceeded $5000/MWh in two occasions. On the day, Snowy Hydro rebid the ramp down rate at Tumut Three and Upper Tumut from 200 MW/min and 130 MW/min, respectively, to the minimum allowable level of 3 MW/min. The reason for the rebids related to previously un-forecast prices at the price cap. They also bid capacity to the price floor.

Spot price event above $5000/MWh in Victoria, 22 April 2010

The events of 22 April 2010 saw the price in Victoria exceed $5000/MWh for seven trading intervals.[18] During the event there were 36 five-minute dispatch intervals where the five minute dispatch price in Victoria was close to the price cap. For every one of those dispatch intervals, Snowy Hydro's Murray generator was being constrained down from high output levels at 3 MW/min. Murray's ramp down rate had been 200 MW/min prior to the high price periods, which Snowy Hydro changed through a rebid. The reason for the rebidding of the ramp rates related to prices being higher than forecast – i.e. commercial reasons. Around the same time as Snowy Hydro rebid its ramp rates it moved capacity into negative prices. Counter-price flows across the VIC-NSW interconnector occurred for the entire period and resulted in $17.5 million of negative residues, the largest-ever single accrual of negative settlement residues.

High Queensland prices during 2011, 2012 and 2013

Congestion on the transmission lines between Calvale-Wurdong and Calvale-Stanwell (in the vicinity of Gladstone) has led to highly volatile prices in Queensland and significant negative settlement residues since July 2011.

Analysis by the AER shows that the use of ramp rates for commercial reasons has exacerbated the market impacts of this network congestion. In December 2012 the AER published a Special Report entitled *The impact of congestion on bidding and inter-regional trade in the NEM*.[19]

The report explained how, as a result of a restructure in July 2011, CS Energy now operates the power stations located on either end of the Calvale-Wurdong line (Gladstone and Callide power stations). CS Energy can contribute to causing congestion by increasing the northerly flow on the line. It can do this by increasing output at Callide, reducing output at Gladstone (which also results in more northerly flow across the line) or both. A generator can change its likely dispatch level by changing the offer price, so CS Energy can increase the flow on the Calvale-Wurdong line by rebidding capacity at Callide into lower prices or by rebidding Gladstone into high prices. This can then cause the constraint to bind, leading to the constraining on or constraining off of generators and QNI. At times CS Energy would rebid to reduce Callide's ramp down rates so that when the constraint bound Callide can only be decreased at a slow rate (3 MW/min).

[18] AER 2010 *Spot prices above $5000/MWh report, Victoria, 22 April 2010*

[19] In December 2012 the AER published a Special Report entitled *The impact of congestion on bidding and inter-regional trade in the NEM* and in March 2013 the AER made a submission to the Productivity Commission's *Electricity Network Regulatory Frameworks Review* entitled *Possible options for interim solutions to congestion-related disorderly bidding*. Both reports are attached.

Analysis of the commercial use of ramp rates causing or exacerbating network congestion

The AER has reported numerous examples of network congestion leading to large changes in the dispatch of generation and price fluctuations. During such periods, some generation is ramped up and other generation is ramped down but the changes for each unit are always limited by the ramp rate being offered. This can lead to a large dislocation of dispatch and a large un-forecast change in price (with the price often jumping to close to the price cap). The price spike often disappears as quickly as it arose, as over the following dispatch intervals sufficient generation has ramped to new levels so that economic dispatch for most generation can resume.

To attempt to quantify the impact of generators having higher ramp ramps rates during these periods, the AER analysed several individual dispatch intervals during December 2012 and January 2013 when short-term congestion-related price spikes occurred. Using AEMO's NEMDE-queue facility, very small increases to the ramp up or down rate of generators were made. The results showed that with only small changes to the offered ramp rates of a limited number of generators,[20] the increased degree of freedom available to the dispatch algorithm meant that the extreme price volatility did not occur.

Relative advantage of large aggregated generators

As it currently stands, the 3 MW/min rule creates an advantage for large aggregated generators that can significantly exacerbate the market impacts of network congestion. Large aggregated generators, such as Snowy Hydro's upper and lower Tumut facilities (and the Murray facilities), which are capable of a ramp rate of 200 MW/min, on occasion rebid their ramp down rates to the minimum allowable of 3 MW/min in the presence of congestion. In the AER's view this results in a disproportionate burden on other generators or interconnectors as their output is changed instead of Tumut. This in turn increases the risk profile of those other generators and lessens their ability to hedge. The large impact on the flows across interconnectors when certain constraints bind also reduces the effectiveness of inter-regional settlements residues to purchasers of those rights, which reduces the ability to hedge between regions. Had the rapid reduction in ramp rate down not occurred, flows would not have been counter price and negative settlement residues would not have occurred (which in turn flows through to transmission use of service (TUoS) prices.

The issue of fairness/equity between generators has been considered by the AEMC previously. In the AER's 2008 rule change proposal (where the AER proposed that the 1MW/min minimum be changed to 3MW/min minimum), the AEMC's draft decision proposed that the minimum apply to the individual generating units that form part of an aggregated unit. Therefore, taking Tumut as an example, Tumut would have been treated as six units, so its minimum ramp rate would be 18 MW/min. However, Snowy (and others) argued against this, and the AEMC moved away from this approach in its final decision, so that aggregated units such as Tumut are treated, in effect, as a single unit. The AER understands this is the approach taken by participants, including Snowy specifying the maximum ramp rates requirements of Schedule 3.1 of the rules.

[20] Generators with high coefficients in the constraint equations have the greatest impact on relieving congestion, so it was these generators which the AER focussed on. For more explanation of coefficients in constraint equations, see Appendix C.

Proposed Ramp Rate Rule change

The AER has considered a range of different options in relation to ramp rate rule changes, including four alternatives to achieve the objective of placing a greater restriction on generator ramp rates (the arguments for and against each approach is contained in Appendix A).

The AER's preferred option (and the subject of this Rule change proposal) is to require generators to always submit ramp rates that reflect their technical capability at the time. This essentially means providing a ramp rate to AEMO that is the maximum the generator can safely attain at that time. The rule change proposal would apply equally to scheduled and semi-scheduled generators, scheduled network services and scheduled loads. Proposed changes to clause 3.8.3A to achieve this are contained in Appendix D. The AER's proposed approach to monitoring and enforcing compliance with this requirement is described under *AER's proposed approach to compliance*.

Dispatch inflexibility profile

Clause 3.8.19(d) provides a fast start generator with the discretion to provide an FSIP as part of its dispatch offer. Essentially, an FSIP is data that market participants (including generators) may provide to AEMO to specify dispatch inflexibilities in respect of their units. This mechanism is used by fast start plant such as gas turbines, to inform the dispatch process of minimum start and stop times, and of minimum safe operating levels.

Like ramp rates, an FSIP is a set of technical parameters that is used in the dispatch process to restrict the way a generator can be dispatched. The AER considers that like ramp rates, the intention of clause 3.8.19(e) is that a generator submits an FSIP that reflects its technical capabilities. AEMO must endeavour to dispatch the generator within these technical capabilities. As shown in figure 1 above, the CVP associated with violating an FSIP constraint is higher than for satisfactory and secure network limits.

However, the rules are imprecise and participants can change these dispatch inflexibility profiles through the rebidding process for any reason. That is, as the rules currently stand, participants can use these technical parameter for commercial advantage.

This rule change proposal seeks to require fast start generators to submit an FSIP that reflects the technical limitations of the plant. On the basis that this was the original intention of the clause, the AER does not consider that this proposed rule change proposal would create unnecessary hardships for fast start generators. Proposed changes to clause 3.8.19(d) to achieve this are contained in Appendix D. The AER's proposed approach to monitoring and enforcing compliance with this requirement is described under *AER's approach to compliance*.

AER's proposed approach to compliance

The AER appreciates that, given the variable and technical nature of ramp ramps, concerns may be raised with respect to how such a change to the rules may be enforced. Accordingly, to provide further clarity on how the proposed rule would operate in practice and how the AER would enforce it, the AER would amend its *Rebidding and Technical Parameters*

Guideline. The AER would consult on this in accordance with the rules consultation procedures.

Generally speaking, registered participants would be required to ensure the ramp rate being offered reflects the maximum the generator can achieve under the conditions at the time, or expected output of the plant under anticipated conditions in the forecasting horizons. As outlined in the *Rebidding and Technical Parameters Guideline* ramp rates may be provided through other mechanisms, including directly from the power station through the Supervisory Control And Data Acquisition (SCADA) system. This must also reflect the maximum the generator can achieve under the conditions at the time. The more limiting of the offer and that provided through SCADA is used in dispatch. If the ramp rate provided through SCADA is more restrictive then a rebid to reflect this must be made as soon as possible.

The AER recognises that when submitting offers, bids or rebids for a future timeframe (i.e. in the pre-dispatch timeframe), it may be difficult for generators to precisely determine the maximum ramp rate at that future point in time. In this case the AER would expect participants to submit ramp rates that are typical of what the generator could achieve based on the forecast conditions. However, the AER would expect that closer to the dispatch timeframe participants would be more aware of the maximum capability of their plant and that their offered ramp rate should be refined to reflect this.

In considering compliance with the proposed rule it is instructive to consider the obligation that currently exists in the rules for compliance with dispatch instructions. In 2006 the AER issued a compliance bulletin outlining its approach to monitoring the responsibilities of participants to follow dispatch instructions as required by clause 4.9.8(a) of the rules.[21] The objective of this compliance bulletin was to clarify the AER's expectations, including the approach the AER intends to take with respect to monitoring compliance with these provisions of the Rules. The bulletin states:

> The AER also recognises that while Registered Participants must endeavour to comply with dispatch instructions exact compliance with dispatch instructions in every dispatch interval is a physical impossibility. Accordingly, the AER does not intend to pursue a breach of clause 4.9.8(a) with respect to minor departures from dispatch instructions that occur despite the best endeavours of a Registered Participant to comply.

In a similar way the approach the AER intends to take with respect to monitoring compliance with proposed rule would be outlined in a revised version of the *Rebidding and Technical Parameters Guideline.* In principle this would require that if the expected ramp rate in the offer differed materially from its technical maximum capability then it would be required to submit a rebid to vary its ramp rate.

Currently under the rules, if a participant provides a ramp rate under 3 MW/min it must simultaneously provide AEMO with a brief, verifiable and specific reason. The brief, verifiable and specific reason must relate directly to the technical reason preventing the relevant generating unit, scheduled load or scheduled network service from attaining the required minimum ramp rate. However, under this rule change proposal, each time a participant determines that the offered ramp rate differs materially from its technical

[21] AER 2006, *Compliance Bulletin No 1 - complying with dispatch instructions*

maximum capability then it would be required to submit a rebid to vary its ramp rate, and the brief, verifiable and specific reason would need to directly relate to the technical reason for doing so. The amended *Rebidding and Technical Parameters Guideline* will outline when a change in ramp rate warrants a technical rebid reason. As is the case under the current rules, the AER would be entitled to require that the generator provide additional information to substantiate and verify the reason provided.

As a matter of principle, the AER would take a pragmatic approach to monitoring and enforcing compliance with proposed clause 3.8.3A. Specifically, we would generally not be examining precise ramp rate values at all times, and we would not expect to pursue a breach of clause 3.8.3A with respect to minor variations in offered ramp rates. Instead we would focus our attention on ramp rates under certain market conditions where there may exist a driver to rebid a ramp rate for commercial rather than technical reasons. For example, the AER would be likely to check the ramp rates of generators when there are high prices and network congestion is causing NEMDE to limit their output, to assess whether they appear within the range of their typical maximum ramp rate. Where appropriate the AER may also engage independent experts to verify actual plant capabilities.

When deciding on an appropriate response upon the discovery of a potential breach of clause 3.8.3A, the AER would, as it does with all potential breaches, take into account all relevant facts including:

(a) the nature and extent of the breach;

(b) the nature and extent of any loss or damage suffered as a result of the breach;

(c) the circumstances in which the breach took place; and

(d) whether the relevant participant has engaged in any similar conduct.[22]

On the basis of these factors, the AER will determine an appropriate response. If the new clause 3.8.3A remains a civil penalty provision (which the AER would support), the AER could (as is currently the case under 3.8.3A(d)) issue an infringement notice or institute legal proceedings.

In terms of the proposed changes to the clauses relating to FSIPs, new proposed clause 3.8.19(h) (as shown in Appendix D) would require participants who submit an FSIP to ensure the parameters reflect the actual MW capacity and time inflexibilities of the generating unit at the time. As for the case for ramp rates, the AER would take a pragmatic approach to monitoring and enforcing compliance with the requirement to submit a "technical" FSIP. Again, the AER would not examine precise FSIP parameters at all times. Instead we would focus our attention on FSIPs under certain market conditions where there may exist a driver to rebid an FSIP for commercial rather than technical reasons. For example, we may examine whether the unit's "T" times are a true reflection of its technical capability under high price conditions. Reinforcing the importance of this proposed clause, it would also attract a civil penalty.

[22] AER 2010 *Compliance and Enforcement Statement of Approach*, December 2010

D How the proposal contributes to the National Electricity Objective

The national electricity objective (the objective) is stated in section 7 of the National Electricity Law as being:

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –*
>
> *(a) price, quality, safety, reliability and security of supply of electricity;*
>
> *(b) the reliability, safety, and security of the national electricity system.*

The AER considers the proposed Rule change will contribute to the objective in several key ways, as follows.

System security

Requiring generators to bid a technical ramp rate at all times will provide AEMO with the ability to move generators more quickly to alleviate a constraint. Under the section *Example of the implications of the current Rules,* (above) it was highlighted that if large generators like Snowy Hydro's Tumut facility reset their ramp rate to 3 MW/min, the current minimum allowed, (e.g. for commercial reasons such as when prices are high and a constraint is binding that is trying to force Tumut to lower output levels), it would take 10 hours to ramp down to zero output. However, Snowy Hydro's Tumut facility is also generally capable of achieving a ramp-down rate of 200 MW/min. Requiring the generator to bid the maximum ramp rate it is technically capable of achieving at the time would enable the constraint to be alleviated more quickly, hence enhancing system security. This contributes to the objective through improving the safety, reliability and security of supply of electricity and the national electricity system.

Price of supply of electricity

As discussed above, over the last three years the increasing prevalence of disorderly bidding has created unnecessary price volatility, led to inefficient dispatch and created counter price flows across interconnectors. As a result, the ability for market participants to manage risk across interconnectors has reduced and with it competition between regions. The increased prevalence of counter price flows has also led to increased transmission use of service (TUOS) charges in importing regions (which ultimately flows through to consumers' energy bills).

Some retailers own generation assets as a "physical" hedge to mitigate spot market exposure. However, because the price spikes associated with disorderly bidding are often unforecast and occur at short-notice, peaking plants (which typically take longer than 5 minutes to start) are not as effective at hedging which increases costs.

Further, increased volatility in the wholesale market affects the price of hedge contracts, which will flow through to retail tariffs. Prices for hedge contracts are based on the market's expectation of spot prices adjusted by a risk premium. Increased spot volatility leads to an expectation of similar volatility in the future, which can lead to an increase in the risk premium.

Efficient investment in transmission infrastructure

A costly approach to addressing the problem of congestion related disorderly bidding would be to "build the problem out" through increased investment in transmission infrastructure. The AER considers that implementing this partial solution (of requiring generators to bid and rebid the maximum ramp rate they are capable of achieving) while the AEMC undertakes the work required to potentially implement the longer term solution of the optional firm access model may negate short-term inefficient investment in transmission infrastructure, thereby promoting longer term efficient investment in transmission infrastructure.

E Costs and benefits and potential impacts on those likely to be affected

Potential costs

Plant wear and tear

Some participants may argue that there are costs associated with requiring their plant to operate at the technical ramp rate limits at all times (compared with the current lower limit of 3 MW/min). Operating plant at, or close to, its technical ramp rate limits can lead to rapid changes in output up or down from time to time. It could be argued that in the extreme, this could increase wear and tear and result in associated increased maintenance costs.

However, the AER does not consider this to be a valid argument because generators have the ability to rebid volumes within price bands to limit the amount and the frequency by which their output changes, thereby negating potential wear and tear. For example, if a generator is the marginal unit in the region (or the NEM) then it could be ramped up and then down and then up again from dispatch interval to dispatch interval. To avoid this, the generator could decrease its availability in the price band that it is currently being varied within.

Potential to de-engineer plant

It may also be argued that requiring generators to bid their technical limits at all times may give them the incentive to "de-engineer" their plant to reduce the technical ramp rate capability. However, the AER considers it is unlikely this would happen. The reason is, for the vast majority of the time (apart from periods of local congestion leading to disorderly bidding) generators have an incentive to maintain flexible plant so they can respond quickly to high or low prices. The AER understands, however, that when constraints bind, this ability to be moved rapidly can be financially damaging, because generators can be constrained off when they would rather be generating and receiving a high price. However, this is using ramp rates as a commercial parameter.

Benefits of Rule change

The AER considers that, if made, this rule proposal would mitigate the most egregious cases of disorderly bidding and would have broad and long term benefits to the market as a whole. The benefits, as discussed above, would be a reduced ability for generators to manufacture congestion, reduced spot price volatility (and a resultant improved ability for intra-regional hedging), reduced counter price flows across interconnectors, improved firmness across interconnectors during high spot price events (and a resultant improved ability for inter-regional hedging), a reduction in negative inter-regional settlement residues and an improvement in SRA proceeds. The AER considers there would be an improvement in interregional competition, and ultimately end-use consumers would benefit through lower prices.

Another strong advantage of requiring generators to bid in their technical ramp rates is that it would also help to ensure that AEMO has at its disposal the highest level of flexibility that the market can provide to aid in the management of system security and promote the efficiency of dispatch. A large number of short duration price spikes occur following relatively small step changes in supply or demand (reductions in either network or generator capacity or increases in demand). Limited ramp rate capability results in the dispatch of higher priced capacity than would otherwise occur and can lead to system security issues when NEMDE does not have enough capability to move generators to resolve network constraints.

Appendix A

Alternatives for a greater restriction on generator ramp rates

Approach A: One approach might be to change the minimum allowable ramp rate so that it would apply to individual physical generating units rather than aggregated units (consistent with the AEMC's draft decision on the 2008 rule change proposal). This would increase the minimum ramp rate for a number of large units (in particular Murray and Tumut, which are the largest units in the NEM) and reduce the prevalence of counter price flow resulting from disorderly bidding. The disadvantage to this approach is that large individual units would still be able to submit a very low ramp rate compared to its technical capability.

Approach B: One approach might be to change the Electricity Rules to additionally require that when a network constraint binds, each generator on the left hand side (LHS) has to bid in their maximum technical ramp rate. Evidence of rapid rebidding that occurs in response to congestion (with congestion given as the reason), suggests that generators are fully aware when a network constraint is binding. Such an approach would also assist system security as NEMDE would be able to select the most effective method of addressing congestion in the network.

The disadvantage of this approach is it requires generators to rebid once they become aware a constraint is binding. There is a question of how long a generator would need to maintain the ramp rates at the technical limit level. In a worst case scenario, the rebidding of ramp rates could alleviate the constraint such that it no longer binds. If generators then rebid ramp rates back to their previous level, in some circumstances this could trigger a circular situation where the same constraint starts binding again within a short time frame.

Approach C: A further alternative would be to change the rules so that generators must specify a ramp-rate of at least a certain percentage (say 3 per cent) of their capacity (unless there is technical limitation on their plant). This would lower the inefficiencies caused by disorderly bidding. A minimum of 3 per cent per minute ramp-rate would mean that any generator could be ramped down to zero in around 33 minutes (subject to technical limitations).

The disadvantage of this approach is that it represents a large increase in the minimum ramp rate for the larger thermal generators to a level possibly beyond their technical capability. For example, the 560 MW brown coal Loy Yang A units would be required to increase their ramp rate to 16 MW/min, which is above their technical capability, so the (lower) technical limitation based ramp rate would have to apply. Therefore many units may be affected by this change and would be required to operate at their technical limitation based ramp rate. This led the AER to consider approach D.

Approach D: This approach would require generators to bid a technical ramp rate at all times. This is the preferred approach and is explained in detail in the main body of this paper.

Appendix B

Tables A1 and A2 show that on 23 occasions since December 2009 disorderly bidding as a result of network congestion has led to significant counter price flows between Victoria and New South Wales. Tables A1 and A2 list each event where disorderly bidding led to more than $150 000 in negative settlement residues into New South Wales and Victoria respectively. The tables outline for each event the maximum counter price flow, the maximum price in the higher priced region and the negative settlement residues that occurred.

Table A1: Summary of high cost recent examples of counter price flow into New South Wales

Date	**Maximum spot price ($/MWh)**	**Maximum counter price flow (MW)**	**Negative settlement residue ($)**
9/02/2010	7847	560	1 150 000
10/02/2010	1489	497	717 000
21/04/2010	2093	496	1 143 000
22/04/2010	9999	641	17 491 000
21/06/2010	1756	894	259 000
22/10/2010	2470	1108	983 000
28/11/2010	115	1417	157 000
31/01/2011	9597	174	440 000
30/05/2011	1814	1039	1 032 000
31/05/2011	166	908	226 000
2/07/2012	4364	126	172 000
11/09/2012	2221	769	1 325 000
13/12/2012	2185	316	229 000
18/02/2013	1937	259	261 000
28/05/2013	1426	309	212 000
Total			**25 797 000**

Table A2: Summary of high cost recent examples of counter price flow into Victoria [23]

Date	Maximum spot price ($/MWh)	Maximum counter price flow (MW)	Negative settlement residue ($)
7/12/2009	7715	37	230 000
22/01/2010	4514	205	214 000
4/02/2010	5541	1365	5 025 000
11/02/2010	1998	152	173 000
26/03/2010	1836	226	205 000
13/04/2010	3081	529	805 000
29/06/2010	4987	194	472 000
9/11/2011	6498	685	1 734 000
Total			**8 858 000**

[23] The 16 October 2012 event is not included as negative settlement residues were less than $150 000.

Table A3 lists each event where congestion in the Gladstone region and disorderly bidding led to more than $150 000 in negative settlement residues into New South Wales. The table outlines for each event the maximum counter price flow, the maximum price in the higher priced region and the negative settlement residues that accrued.

Table A3: Significant counter price flows related to congestion around Gladstone

Date	**Maximum spot price ($/MWh)**	**Maximum counter price flow (MW)**	**Negative settlement residue ($)**
5/09/2011	2117	569	371 000
12/01/2012	1757	917	993 000
15/01/2012	228	1148	183 000
27/01/2012	509	966	303 000
29/01/2012	2080	1257	1 272 000
14/02/2012	360	876	222 000
20/02/2012	503	667	185 000
21/02/2012	392	1004	196 000
22/02/2012	438	772	256 000
2/03/2012	317	872	308 000
3/03/2012	265	854	272 000
4/03/2012	339	491	165 000
5/03/2012	289	1155	248 000
6/03/2012	268	898	202 000
9/03/2012	260	1079	278 000
10/03/2012	196	1118	234 000
23/03/2012	396	969	297 000
25/08/2012	646	785	346 000
30/08/2012	463	900	179 000
31/08/2012	311	1147	302 000
1/09/2012	603	1078	293 000
3/09/2012	370	1112	512 000
8/09/2012	408	978	246 000
27/10/2012	1085	934	410 000
5/12/2012	368	826	359 000
2/01/2013	1953	692	743 000
12/01/2013	879	654	272 000
13/01/2013	2918	547	206 000
14/01/2013	2499	606	858 000
16/01/2013	451	342	171 000
17/01/2013	550	894	590 000

18/01/2013	1989	808	808 000
19/01/2013	544	678	169 000
20/01/2013	1345	832	835 000
8/02/2013	278	900	338 000
10/02/2013	297	1057	199 000
14/02/2013	214	674	313 000
15/02/2013	385	779	335 000
Total			**14 469 000**

Appendix C

How constraint equations operate

Constraint equations

One of AEMO's responsibilities as the market and system operator is to manage the network to ensure that transmission elements are not overloaded and system security is maintained. Where transmission elements become congested, they are referred to as being constrained. To manage network flows AEMO utilises constraint equations in NEMDE, which runs every five minutes. A constraint equation is used to determine the optimal dispatch of generators based on their offers (or bids) to manage flows on specific transmission lines (and other equipment) for each five minute dispatch interval.

Each constraint equation consists of a Left Hand Side (LHS) and a Right Hand Side (RHS). The RHS signifies the outer point of an outcome, beyond which a line could become overloaded in the event of the 'credible contingency' the constraint is designed to manage.[24] A 'credible contingency' includes, for example, the loss of another line or a generator. The RHS contains all of the inputs that cannot be varied by NEMDE. These inputs include demand and the rating of the relevant transmission line (i.e. how much energy the line can carry without damaging the line or causing unsafe conditions). The LHS contains all of the inputs that can be varied by NEMDE to deliver an outcome that satisfies the requirement of the RHS. These inputs include output from generators and flow on interconnectors.

How NEMDE deals with constraints

Constraint equations are used in NEMDE together with generator bids to determine the optimal economic dispatch of generators to meet customer demand. All else being equal, if the flow over a particular element of the transmission system is within the requirements of the RHS, then the relevant constraint equation does not affect NEMDE dispatching generators in accordance with 'merit order' or 'economic dispatch' (by 'merit order' or 'economic dispatch' the AER means least-price offers of generation capacity are dispatched first). When the LHS of a particular constraint equation is equal to the RHS, the constraint is considered to be at its limit and is 'binding'. In this situation, NEMDE may need to affect dispatch outcomes to satisfy the constraint in preference to economic dispatch.

NEMDE is designed to avoid or minimise violating a constraint equation. Violations occur on the rare occasion when the LHS is greater than the RHS; that is, the flow over the line could be greater than its rating if the relevant credible contingency occurs in the next five minutes.[25] A binding constraint equation affects dispatch until the constraint no longer binds.[26]

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[24] If the constraint equation is not satisfied it is termed as 'violated'.

[25] Constraint equations can be expressed as LHS $\leq$ RHS or LHS $\geq$ RHS. For the purposes of this report, the descriptions of constraint equations are limited to LHS $\leq$ RHS. These are the most common types of constraint equations used to manage network limits.

[26] The constraint may stop binding due to for example an increase in line rating (which can be influenced by ambient weather conditions) or changes in generator offers.

To control the flow over a bound line to avoid violating the constraint, NEMDE attempts to change the LHS inputs. For example, NEMDE may try to increase (out of merit order) the output of generators or interconnectors closer to a relevant load/demand centre ('constrain on' a generator or interconnector). By increasing generation closer to the load/demand, it can in effect reduce the congestion on the transmission system. Alternatively, NEMDE can reduce (out of merit order) the output of generators or interconnectors that are a source of the flow over the transmission line ('constrain off' a generator or interconnector). NEMDE may also adopt a combination of these actions, depending on the specific constraint equation that is binding.

While the priority is system security and avoiding violations of constraints, NEMDE still attempts to find the least cost way of dispatching generation out of the options available. Therefore if, for example, there are several generators that could be 'constrained on', it will choose the lowest cost combination taking into account the prices offered and the coefficients (see discussion of coefficients below). The ability of the system to change generator outputs and interconnector flows to manage network congestion is termed 'fully co-optimised dispatch'.

When NEMDE changes flows over an interconnector (by 'constraining on' or 'constraining off' an interconnector), NEMDE changes the output of generators in adjoining region(s). This does not involve constraining particular generators, rather NEMDE reduces or increases the level of supply that is sourced from interstate generators.

Coefficients in constraint equations

As was noted earlier, the LHS of constraint equations contain all of the inputs that can be varied by NEMDE to avoid violating the constraint, such as output from generators and flow on interconnectors. Each generator or interconnector on the LHS has a coefficient, which reflects the impact it has on the constrained transmission line. In other words, the effect of a one MW change in the output of a particular generator (or flow on a particular interconnector) on flows over the constrained line is reflected in the coefficient assigned in the LHS. For example, if a one MW reduction in output of a generator decreases flow on the constrained line by one MW, the coefficient is +1. A positive coefficient means that a generator may be 'constrained-off' when the constraint binds, while a negative coefficient means a generator is 'constrained-on'. The further away a generator or interconnector is located from the constrained line, the greater the change in output required to achieve a one MW change in flow over the constrained line. This is reflected by a smaller coefficient.[27]

There is a threshold below which it is deemed that variable inputs, including generators and interconnectors, will not be included in the LHS of constraint equations. The purpose of the threshold is to exclude those inputs, such as the output of a generator, whose variance would not materially enhance system security due to the size of their coefficient. This threshold is determined by AEMO in its *Constraint Formulation Guidelines*.[28] The guideline specifies that if an input has a coefficient of less than 0.07 then it will not be optimised, but its output will be taken as given (as determined by normal economic dispatch).

[27] Note that coefficients are normalized, which means that sometimes a coefficient of 1 may not mean a 1 MW change in flows on the constrained line, but a generator or interconnector with a coefficient of 1 has the largest impact.

[28] AEMO 2010, *Constraint Formulation Guidelines*

The threshold was determined by AEMO calculating the smallest coefficient for a generator (the relevant generator) below which a small change in the output of one generator would require an unacceptably large swing in the output of a small coefficient generator on the same constraint. No specific consideration, however, was given to interconnectors, which can change rapidly as set out below. The same threshold for generators and interconnectors was used for consistency reasons only.

Technical limitations when constraining on/off

As noted earlier, when a constraint binds NEMDE tries to find the optimal outcome (which prioritises the dispatch of low priced generation) to manage the constraint. A further requirement NEMDE must incorporate is adherence to the technical limitations of the relevant generators. When submitting offers, generators have to specify the rate at which their plant can increase or decrease the level of output in MW per minute. This rate of change is referred to as the ramp rate. Generators must specify a ramp rate that is 3MW/min or higher unless there is technical limitation on their plant. An interconnector is treated as having no ramp rate and therefore NEMDE can rapidly change the level and direction of flows on interconnectors.

Appendix D

Suggested drafting

Suggested amendments to clause 3.8.3A (Ramp Rates) of the National Electricity Rules

Amend clause 3.8.3A as follows (insertions underlined and deletions in strikethrough):

3.8.3A Ramp Rates

(a) This clause 3.8.3A applies to a *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant* with *generating units*, *scheduled network services* and/or *scheduled loads* providing *ramp rates* to *AEMO* in accordance with the following clauses:

(1) with respect to notification of scheduled capacity prior to *dispatch*:

(i) clause 3.8.4(c);

(ii) clause 3.8.4(e);

(iii) clause 3.8.4(d);

(2) with respect to offers for *dispatch*:

(i) clause 3.8.6(a)(2);

(ii) clause 3.8.6(g);

(iii) clause 3.8.6A(b);

(iv) clause 3.8.7(c); and

(3) with respect to *rebids*, clause 3.8.22(b)

Amend clause 3.8.3A(b) as follows:

(b) ~~Subject to clauses 3.8.3A(c) and 3.8.3A(i), a~~ <u>A</u> *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant* to which this clause 3.8.3A applies must provide an up *ramp rate* and a down *ramp rate* to *AEMO* for each *generating unit*, *scheduled network service* and/or *scheduled load* that is <u>the maximum the relevant *generating unit*, *scheduled load* or *scheduled network service* can safely attain at that time.</u>

Note

<u>This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)</u>

(1) [**Deleted**]

(2) [**Deleted**]

Note **[Deleted]**

(c) [**Deleted**]

(d) [**Deleted**]

(e) [**Deleted**]

(c) ~~(f)~~ The *AER* may require, upon written request, the *Scheduled Generator, Semi-Scheduled Generator* or *Market Participant* to provide such additional information as it may require from time to time to substantiate and verify the ~~reason~~ *ramp rates* provided in accordance with clause 3.8.3A~~(e)~~(b).

(d) ~~(g)~~ The *AER* must exercise its powers under clause 3.8.3A(c)~~(f)~~ in accordance with any guidelines issued by the *AER* from time to time in accordance with the *Rules consultation procedures*.

(h) [**Deleted**]

(i) [**Deleted**]

(j) [**Deleted**]

Note **[Deleted]**

Suggested amendments to clause 3.8.19 (Dispatch inflexibilities) of the National Electricity Rules

Amend clause 3.8.19(e) and insert new clauses 3.8.19(h) (a civil penalty provision), 3.8.19(i) and 3.8.19(j) as follows (insertions underlined and deletions in strikethrough):

(e) A *dispatch inflexibility* profile for a *generating unit* must contain the following parameters to indicate its MW capacity and time related *inflexibilities*:

(1) The time, T1, in minutes, following the issue of a *dispatch instruction* by *AEMO* to increase its loading from 0 MW, which is required for the *plant* to begin to vary its *dispatch* level from 0 MW in accordance with the instruction;

(2) The time, T2, in minutes, that the *plant* requires after T1 (as specified in subparagraph (1)) to reach ~~a specified~~ its minimum MW *loading level*;

(3) The time, T3, in minutes, that the *plant* requires to be operated at or above its minimum MW *loading level* before it can be reduced below that level;

(4) The time, T4, in minutes, following the issue of a *dispatch instruction* by *AEMO* to reduce loading from the minimum MW *loading level* (specified under subparagraph (2)) to zero, that the *plant* requires to completely comply with that instruction;

(5) T1, T2, T3 and T4 must all be equal to or greater than zero;

(6) The sum (T1 + T2) must be less than or equal to 30 minutes; and

(7) The sum (T1 + T2 + T3 + T4) must be less than 60 minutes.

(f) A *dispatch inflexibility profile* for a *scheduled load* must contain parameters to indicate its MW capacity and time related *inflexibilities*.

(g) *AEMO* must use reasonable endeavours not to issue a *dispatch instruction* which is inconsistent with a *Scheduled Generator's*, *Semi-Scheduled Generator's* or *Market Participant's dispatch inflexibility profile*.

(h) In the event that a *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant* provides *AEMO* with a *dispatch inflexibility profile* in accordance with clause 3.8.19(d), the parameters provided in accordance with clause 3.8.19(e) and clause 3.8.19(f) must reflect the actual MW capacity and time *inflexibilities* of the *generating unit* at that time.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(i) The *AER* may require, upon written request, the *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant* to provide such additional information as it may require from time to time to substantiate and verify the information provided in accordance with clause 3.8.19(e) and clause 3.8.19(f).

(j) The *AER* must exercise its powers under clause 3.8.19(i) in accordance with any guidelines issued by the *AER* from time to time in accordance with the *Rules consultation procedures.*

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22 March 2013

Philip Weickhardt
Presiding Commissioner
Productivity Commission
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MELBOURNE VIC 8003

Dear Mr Weickhardt

Submission on potential interim solutions to address disorderly bidding

Please find attached a supplementary submission from the Australian Energy Regulator (AER) regarding short term solutions to congestion issues.

This submission is further to a request from the Commissioners at the Productivity Commission's public hearing for the Electricity Network Regulatory Frameworks Review in Sydney in December 2012. As set out in the attached submission, the AER is supportive of a range of possible interim solutions being considered. The AER considers that the solutions that are likely to have the most merit in the short term would be a combination of, firstly, National Electricity Rule changes so that generators must bid in their technical ramp rate, and secondly, a review by the Australian Energy Market Operator (AEMO) of the minimum coefficients for interconnectors in transmission constraint equations. The AER also considers that a simplified congestion management mechanism should be considered as a priority. This could be a stepping stone to the full Optional Firm Access proposal being considered by the Australian Energy Market Commission (AEMC), or could be an effective stand alone mechanism that assists in addressing the concerns.

The AER would be pleased to provide further assistance to the Commission on this important area of work. If you would like to discuss any aspect of this submission please contact Tom Leuner, General Manager, Wholesale Markets, on (03) 9290 1890.

Yours sincerely

Andrew Reeves
Chair
Australian Energy Regulator

AER Submission

Possible options for interim solutions to congestion-related disorderly bidding

March 2013

Contents

1 What is congestion-related disorderly bidding?

In December 2012 the AER published a special report *"The impact of congestion on bidding and inter-regional trade in the NEM".*[1] That report concluded that, over the last three years in particular, the increasing prevalence of disorderly bidding has created unnecessary price volatility, led to inefficient dispatch and created counter price flows across interconnectors. As a result, the ability of market participants to manage risk across interconnectors has reduced and with it competition between regions. This submission should be read in conjunction with attached special report.

The special report focussed on the impacts of inter-regional trade between Queensland, New South Wales and Victoria. Shortcomings in the market design incentivise disorderly bidding by generators when faced with being constrained. Network constraints can occur anywhere in the NEM and accordingly any interconnector, not just the Queensland to New South Wales interconnector and Victoria to New South Wales interconnector (VIC-NSW), is at risk of counter price flows precipitated by disorderly bidding. All regions have been impacted by disorderly bidding in the past.[2]

Disorderly bidding and counter price flows associated with congestion around Gladstone in Queensland has continued into 2013. In the first three weeks of January, for example, there were 80 occasions when the spot price exceeded $300/MWh, with 16 of those over $1000/MWh.[3] These price spikes were not driven by excessively high demand but rather network constraints and the last minute rebidding behaviour by CS Energy and Stanwell generators. Once again there have been persistent counter price flows from Queensland into New South Wales during the periods of high prices, leading to almost $8 million in negative settlement residues into New South Wales during January and February 2013. New South Wales customers ultimately pay for these negative settlement residues through charges for transmission.

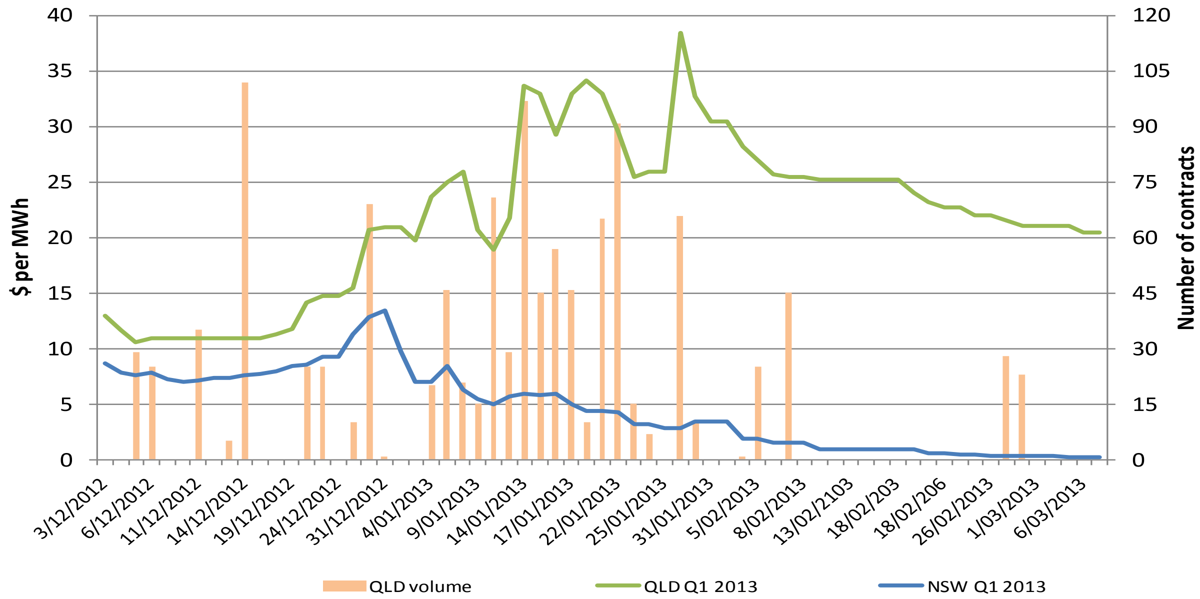
The impacts of these volatile prices are reflected in the value of the futures market in Queensland. The price of Queensland $300 cap contracts (i.e. the premium paid by the buyer to enter into the contract) for Q1 2013 diverged from the prices in other regions during the quarter. Figure 1 sets out prices for Q1 2013 $300 cap contracts for Queensland and New South Wales for comparison, along with the volume traded for the Q1 2013 Queensland caps, from December to early March.

1 The report is available at http://www.aer.gov.au/node/18855

2 Disorderly bidding by the Basslink Market Network Service Provider interconnector has led to it gaining an advantage over Victorian generators, which is the subject of a rule change currently under consideration by the Australian Energy Market Commission *"Negative offers from scheduled network service providers"*. Imports into South Australia can reduce following low priced bidding by South Australian generators located close to Victorian border.

3 In addition to these 80 spot prices, a further 36 prices above $300/MWh occurred as a result of tight supplies in Queensland or step changes in supply following large generator unplanned outages.

Figure 1: Prices for Q1 2013 $300 cap contracts on the ASX



Source: ASX/d-cyphaTrade www.d-cyphatrade.com.au

Disorderly bidding is an example of a prisoner's dilemma. In the event of network congestion, if one generator rebids capacity to very low prices and reduces the rate at which it can be ramped down, then its competitors must also do the same to avoid being constrained off more than would have otherwise occurred. This then leads to more volatile pricing and dispatch outcomes. The AER considers that disorderly bidding magnifies, and at times extends, the effects of congestion.

2 The costs of disorderly bidding

The AER considers that the outcomes associated with the recent disorderly bidding in Queensland illustrates some of the economic inefficiencies that can arise. During these events, high priced peaking plant running on liquid fuel was dispatched instead of lower priced coal plant (due to a combination of physical and economic withholding predominantly at coal power stations and/or generators being unable to be ramped up/down sufficiently due to low rates of change). In some instances, peaking plant were unable to respond quickly enough to unforecast high prices (at times set by strategically high priced coal plant) to run, which imposes costs on those market participants. Anecdotally the AER is aware that, in response to the frequency of unforecast high prices, some market participants ran peaking plant in anticipation of a high price (that did not always eventuate) or for periods longer and more frequently than that usually observed. The AER considers that the level of output from peaking plant in Queensland during these periods was unusual given the associated levels of demand.

However, the production inefficiencies associated with high-cost plant operating instead of lower-cost plant and counter-price flows on interconnectors are, in the AER's view, only one aspect of the costs associated with disorderly bidding. The AER considers that disorderly bidding caused by congestion can create very random large fluctuations in the price that are impossible to predict. This increases the risk profile of customers, retailers and generators. This higher risk profile is a cost which ultimately flows through to consumers through higher energy charges. The AER also considers that disorderly bidding greatly reduces the effectiveness of interconnectors, making it much harder for retailers or generators to hedge across region boundaries. This lowers the competitiveness of the wholesale market with longer-term flow on effects to efficiency and prices.

3 Possible long term solution

The Australian Energy Market Commission's (AEMC) Transmission Frameworks Review (second interim report) has recommended changes to the settlement of generators that are located at mispriced connection points through its Optional Firm Access (OFA) model. The AER welcomes the AEMC's work to develop the OFA proposal. It aims to address a range of important issues, including increasing the firmness of interconnector availability, in order to improve energy contract liquidity and competition. While the AEMC has made significant progress, there are many important areas of detail that are yet to be developed.

4 Possible interim approaches

As the AEMC is tackling a range of very complex issues, it is likely that any reforms will take a long time to implement. Therefore, the AER considers that, given the significant and pressing issues associated with disorderly bidding and resultant restricted or counter-price interconnector flows, interim changes should be implemented in the short to medium term to at least partially address the problem. These interim changes would mitigate the egregious cases of disorderly bidding, and improve firmness across interconnectors during high spot price events.

The list below provides a range of possible approaches that would assist in addressing the issue. The first approach addresses the market design issue. It could be a stepping stone towards the OFA model, or it could stand on its own as a solution to disorderly bidding even if the OFA model is never implemented. However, it is potentially controversial and so it may prove difficult to implement in the short term.

The other approaches aim to limit generators' response to some of the incentives the market creates rather than addressing those incentives. These approaches are simpler to implement requiring very little systems implementation, thereby allowing the most rapid introduction. However they are less effective and therefore less preferable.

The approaches are not mutually exclusive. The AER considers that adopting several of the different approaches would be optimal.

4.1 Approach 1: A simplified congestion management mechanism

One approach would be to introduce a simplified congestion management mechanism based on the Shared Access Congestion Pricing (SACP) model proposed in the AEMC's first interim Transmission Frameworks Review report. In the AER's submission to the first interim report we proposed a modified version of the SACP mechanism.[4] The SACP-like mechanism would be able to be implemented via relatively straightforward changes to AEMO's settlement systems. The mechanism could, in effect, be a stepping stone towards the full OFA model and would deliver significant gains. In particular, it could address much of the disorderly bidding problem, which would have flow on effects in terms of improving interconnector flows, the firmness of inter-regional hedges and with it improved competition across the market.

As a stepping stone towards OFA it would also provide valuable lessons to inform the design of the more complex aspects of the OFA model such as transmission network service provider (TNSP) incentive arrangements. It would also provide real world insights for generators prior to the requirement for those generators to choose whether or not to commit to firm access.

The SACP mechanism is relatively easy to implement from a technical perspective. However the allocation of rights to the intra regional settlement surpluses that accrue is contentious. The SACP

[4] AER *Submission to First Interim Report - Transmission Frameworks Review*, January 2012.

mechanism proposed allocation of access to settlement residues based on available generation capacity. However this results in low allocations for interconnectors when all available generation wishes to be dispatched (as evidenced during congestion events where very low or counter price interconnector flows occur). An alternative allocation that could improve the proportion of residues to interconnectors and therefore competition between regions would be to use annual average output for generators and average flow levels for interconnectors. The allocations could be determined annually by AEMO at the same time as transmission loss factors, which are required to be published by 1 April each year.

4.2 Approach 2: A greater restriction on generator ramp rates

A short term approach may include a greater restriction on generators lowering their ramp rates. At the moment, generators must specify a ramp rate that is 3 megawatts (MW) per minute or higher (or 3 per cent for generators less than 100 MW in capacity) unless there is a technical limitation on their plant. For large generators this is a very low ramp rate.

For example, Snowy Hydro's Tumut facility is treated as a single aggregated unit by the NEM dispatch engine, NEMDE, (despite being made up of 6 generation units) and has a maximum capacity of 1800 MW. If it is operating at 1800 MW (which it can reach from zero in less than 10 minutes with a ramp up rate of 200 MW/minute) and bids in a 3 MW/minute ramp down rate, it will take 10 hours to ramp down to zero output. Similarly, the 1500 MW Murray facility (with 14 generation units) is treated as a single aggregated unit by NEMDE.

The events of 22 April 2010 saw the price in Victoria exceed $5000/MWh for seven trading intervals. During the event there were 36 five-minute dispatch intervals where the five minute dispatch price in Victoria was close to the price cap. For every one of those dispatch intervals, the Murray generator was being constrained down from high output levels at 3 MW/minute. Murray's ramp down rate had been 200 MW/minute prior to the high price periods, which Snowy Hydro changed through a rebid. Counter-price flows across the VIC-NSW interconnector occurred for the entire period and resulted in $17.5 million of negative residues, the largest-ever single accrual of negative settlement residues.

The 3 MW/minute minimum requirement followed a proposal from the AER in 2008 to amend the relevant clauses of the National Electricity Rules (the rule became effective from January 2009).[5] Prior to this rule change, generators were able to offer or rebid ramp rates as low as 1 MW per minute. The level of 3 MW per minute was chosen as a compromise between the maximum technically possible and ensuring enough ramping capability was available to AEMO to manage system security.

The 3 MW/minute rule creates an advantage for large or aggregated generators that can significantly exacerbate the disorderly bidding problem. The AEMC's draft decision to change the relevant rules determined that ramp rates would apply to individual physical generating units.[6] Where physical generating units were aggregated, the ramp rates applicable to each separate generating unit were to be added together. In response to that draft decision, a number of participants with aggregated units responded that linking ramp rates to individual generating units placed a disproportionate burden on aggregated generators where a number of smaller generating units have been aggregated.[7] The AEMC's final decision, moved from its draft decision on aggregation to require a minimum ramp rate of the lower of 3 MW/minute or 3 per cent of the registered unit size to apply to both aggregated and non-aggregated generating units (as opposed to individual physical generating units). The AEMC stated that the risk of non-aggregated units applying to AEMO to become aggregated (in order to gain

[5] AEMC 2009, *Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility,* Rule Determination, 15 January 2009, Sydney.

[6] AEMC 2009, *Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility,* Rule Determination, 15 January 2009, Sydney.

[7] The participants were Snowy Hydro (14 units at Murray and 6 units at Tumut for example are aggregated for a combined capacity of 1500 MW and 1800 MW respectively), Hydro Tasmania and AGL (that each have a number of smaller aggregated hydro units).

this advantage) was mitigated by the requirement for AEMO to only approve aggregation if system security was not materially affected (clause 3.8.3(b)).

Aggregated generators, such as Snowy Hydro, which usually offer a ramp-down rate of 200 MW per minute rebid their ramp down rates to 3 MW per minute in the presence of congestion. This results in a disproportionate burden on other generators that are not aggregated – in contradiction to the equity argument put by Snowy Hydro (and others) in its submission to the AEMC's draft decision.

Approach 2A: One approach might be to change the minimum allowable ramp rate so that it would apply to individual physical generating units rather than aggregated units (consistent with the AEMC's draft decision). This would increase the minimum ramp rate for a number of large units (in particular Murray and Tumut, which are the largest units in the NEM) and reduce the prevalence of counter price flow resulting from disorderly bidding.

Approach 2B: The AER has considered whether the Electricity Rules should be changed to additionally require that when a network constraint binds, each generator on the left hand side (LHS) has to bid in their maximum technical ramp rate. Evidence of rapid rebidding that occurs in response to congestion (with congestion given as the reason), suggests that generators are fully aware when a network constraint is binding. Such an approach would also assist system security as NEMDE would be able to select the most effective method of addressing congestion in the network.

The disadvantage of this approach is it requires generators to rebid once they become aware a constraint is binding. There is a question of how long a generator would need to maintain the ramp rates at the technical limit level. In a worst case scenario, the rebidding of ramp rates could alleviate the constraint such that it no longer binds. If generators then rebid ramp rates back to their previous level, in some circumstances this could trigger a circular situation where the same constraint starts binding again within a short time frame.

***Approach 2C**:* A further alternative would be to change the Electricity Rules so that generators must specify a ramp-rate of at least a certain percentage (say 3 per cent) of their capacity (unless there is technical limitation on their plant). This would lower the inefficiencies caused by disorderly bidding. A minimum of 3 per cent per minute ramp-rate would mean that any generator could be ramped down to zero in around 33 minutes (subject to technical limitations).

The disadvantage of this approach is that it represents a large increase in the minimum ramp rate for the larger thermal generators to a level possibly beyond their technical capability. For example, the 560 MW brown coal Loy Yang A units would be required to increase their ramp rate to 16 MW/minute, which is above their technical capability, so the (lower) technical limitation based ramp rate would have to apply. Therefore many units may be affected by this change and would be required to operate at their technical limitation based ramp rate. This led the AER to consider approach 2D.

***Approach 2D**:* A final ramp-rate related rule change approach the AER has considered is to require generators to bid a technical ramp rate at all times. Arguably this is just a refinement to meet the original intent of the 2008 rule change, which separated the commercial parameters of a bid (price and availability, which are both required to be rebid in "good faith") from the technical parameters of a bid (ramp rate, dispatch inflexibilities and frequency control ancillary services trapezia). The reason for this is that generators can utilise the commercial parameters of a bid to determine their desired output. On the other hand NEMDE treats all technical parameters, including ramp rates, in the same way and honours them under almost all circumstances, including by violating network constraints. However, the current actions by generators during disorderly bidding utilise the ramp rates to reduce the effect of congestion on their output for commercial purposes. This creates a situation whereby generators can use a technical element of a bid to achieve a commercial outcome. This conflict in the role of ramp rates must be resolved.

One potential disadvantage of this approach is the possible incentive to “de-engineer” the plant and reduce the technical ramp rate capability. However the likelihood of this perverse outcome is low. For most of the time (apart from periods of local congestion leading to disorderly bidding) generators have an incentive to maintain flexible plant that can respond quickly to high or low prices.

Recognising that the technical ramp rate of plant is not always precisely definable, and to reduce the regulatory uncertainty of this rule change, the definition of technical ramp rate would need to be specified by the AER. The Electricity Rules could therefore require the AER to publish guidelines on this definition and how it would monitor compliance with the obligation to provide a technical ramp rate at all times. If a generator materially changes its ramp rate then the generator would be required to rebid and provide the reasons to AEMO. The AER should be entitled to require that the generator provide additional information to substantiate and verify the reason provided, as is currently the case when generators specify a ramp rate below 3 MW/minute (see 3.8.3A).

4.3 Approach 3: A review of constraint formulation guidelines

In the AER’s special report on congestion we explain how transmission constraint equations operate. There is a threshold below which it is deemed that variable inputs, including generators and interconnectors, will not be included in the LHS of constraint equations. The purpose of the threshold is to exclude those inputs, such as the output of a generator, whose variance would not materially enhance system security due to the size of their coefficient. This threshold is determined by AEMO in its Network Constraint Formulation Guidelines.[8] The guideline specifies that if an input has a coefficient of less than 0.07 then it will not be optimised or controlled, but its output will be taken as given (as determined by normal economic dispatch).

The threshold was determined by AEMO calculating the smallest coefficient for a generator (the relevant generator) below which a small change in the output of one generator would require an unacceptably large swing in the output of a small coefficient generator on the same constraint. No specific consideration, however, was given to interconnectors, which can change rapidly. The same threshold for generators and interconnectors was used for consistency reasons only.

It is worth emphasising that including smaller coefficient terms in constraint equations has a perverse outcome in that, in the presence of disorderly bidding, the generators and interconnectors with the least impact on the constraint are moved the most. This can lead to rapidly changing levels and direction of interconnector flows, five-minute dispatch prices and output from individual generators. Many of the most egregious events (particularly the New South Wales events involving the western Sydney 70/71 lines and the Gladstone congestion in Queensland) result from very small coefficients, with interconnectors being moved many multiples of the volume of plant that was moved by disorderly bidding. The threshold selection involves a trade off, in that more controllable terms (i.e. the lower the threshold) should in theory result in more secure dispatch, but in the presence of disorderly bidding it results in less efficient and more volatile dispatch.

Consideration should be given to AEMO reviewing the constraint formulation guidelines to assess whether a different minimum threshold should be applied to determine if interconnectors are co-optimised. This could prevent rapid changes in interconnector dispatch outcomes that result from network congestion that is remote from the interconnector. Such a change would assist in addressing the changes on interconnectors where the interconnector is only a minor contributor to the congestion (such as for the Queensland congestion issues around Gladstone, and the New South Wales congestion issues around western Sydney). However, it would not solve counter price flows between Victoria and New South Wales that occur as a result of disorderly bidding by Snowy Hydro, as the VIC-NSW interconnector has a high coefficient. (In other words, because the VIC-NSW interconnector

[8] See: http://www.aemo.com.au/en/Electricity/Market-and-Power-Systems/Dispatch/Constraint-Formulation-Guidelines

will always have a high coefficient, changing the minimum threshold will not alter the constraint equation).

There is a potential risk to system security if interconnectors are not co-optimised. This is because NEMDE will not be able to change the interconnector flow to resolve the constraint and therefore have fewer options available to it. However, this proposal would only apply to congestion that is electrically remote from the interconnector (as evidenced by the small coefficient), which would be readily resolved through changing the dispatch of generators close to the constraint. The current arrangements, where rapid changes in output from many generators and interconnectors results in large swings in power flows and voltage levels, also has the potential to cause power system instability.

If approach 3 were to be combined with approach 2D, NEMDE will have significantly improved ability to resolve congestion issues by changing the dispatch of generators close to the constraint (given the changes to ramp-rates proposed in approach 2D), which would therefore alleviate any security concerns arising from introducing approach 3.

The AER accepts that approach 3 would be a complicated piece of work for AEMO, as security of the system may need to be trading off against efficiency benefits. It would most likely take some time to implement. However, once the Network Constraint Formulation Guidelines were amended, reformulating individual constraint equations (for example, certain constraint equations in Queensland) could be done quickly.

Special Report

The impact of congestion on bidding and inter-regional trade in the NEM

December 2012

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Introduction and Summary

This report outlines the current National Electricity Market (NEM) arrangements for managing transmission network congestion and how generators respond to that congestion. It analyses how generators' response to congestion has led to inefficiencies, price volatility and has reduced the ability for market participants to manage risk between regions. The analysis focuses on recent congestion events in Queensland, New South Wales and Victoria. The analysis shows how the prevalence of congestion can be increased through generator rebidding (known as 'disorderly bidding').

We conclude that the current arrangements are leading to significant inefficiencies and lessening competition between regions. The AER considers that incentives for disorderly bidding are a serious problem with the current NEM design. While the optional firm access model proposed in the Australian Energy Market Commission's (AEMC) *Transmission Frameworks Review* should address the concerns, those reforms will take a long time to implement. We recommend fast tracked changes to protect the integrity of the market in the interim. Such changes could include changes to the arrangements for settlement of generators or changes to the bidding rules. In addition, we consider that the Australian Energy Market Operator (AEMO) should review how interconnectors are treated in the *Network Constraint Formulation Guideline*.

The AER has reported on the impacts of congestion and disorderly bidding in many past reports, including its $5000/MWh reports and weekly electricity reports.[1]

Congestion in the NEM

Transmission networks transport electricity from generators to large customers and load centres served by distribution networks. Transmission networks also connect different regions, allowing for the interregional flow of electricity in the NEM.

Congestion occurs when the incremental increase in the amount of electricity that can flow over a particular line or other transmission system element is constrained by physical or system limitations.[2] These limitations usually reflect the ratings of transmission equipment (generally referred to as 'lines' in this report). The ratings of transmission lines are not always constant and are affected by ambient weather conditions.

Congestion impacts on market participants and market outcomes by distorting the economic dispatch of generators and hence market price outcomes. Despite these impacts, a certain level of congestion is expected in an efficient market where the cost of expanding the network to eliminate congestion is greater than the cost of congestion.

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[1] For example, see the 7 December 2009 $5000 report when rebidding by Snowy of capacity at Tumut and Upper Tumut into low prices led to counter-price flows into Victoria, which is published at www.aer.gov.au.

[2] Under the National Electricity Rules (the Electricity Rules), AEMO is required to operate the power system in a secure state. This means that the power system is operated such that it is able to withstand a credible contingency without damaging or destabilising the power supply.

Management of constraints

Constraint equations

One of AEMO's responsibilities as the market and system operator is to manage the network to ensure that transmission elements are not overloaded and system security is maintained. Where transmission elements become congested, they are referred to as being constrained. To manage network flows AEMO utilises constraint equations in the NEM dispatch engine (NEMDE), which runs every five minutes. A constraint equation is used to determine the optimal dispatch of generators based on their offers (or bids) to manage flows on specific transmission lines (and other equipment) for each five minute dispatch interval.

Each constraint equation consists of a Left Hand Side (LHS) and a Right Hand Side (RHS). The RHS signifies the outer point of an outcome, beyond which a line could become overloaded in the event of the 'credible contingency' the constraint is designed to manage.[3] A 'credible contingency' includes, for example, the loss of another line or a generator. The RHS contains all of the inputs that cannot be varied by NEMDE. These inputs include demand and the rating of the relevant transmission line (i.e. how much energy the line can carry without damaging the line or causing unsafe conditions). The LHS contains all of the inputs that can be varied by NEMDE to deliver an outcome that satisfies the requirement of the RHS. These inputs include output from generators and flow on interconnectors.

How NEMDE deals with constraints

Constraint equations are used in NEMDE together with generator bids to determine the optimal economic dispatch of generators to meet customer demand. All else being equal, if the flow over a particular element of the transmission system is within the requirements of the RHS, then the relevant constraint equation does not affect NEMDE dispatching generators in accordance with 'merit order' or 'economic dispatch' (by 'merit order' or 'economic dispatch' the AER means least-price offers of generation capacity are dispatched first). When the LHS of a particular constraint equation is equal to the RHS, the constraint is considered to be at its limit and is 'binding'. In this situation, NEMDE may need to affect dispatch outcomes to satisfy the constraint in preference to economic dispatch.

NEMDE is designed to avoid or minimise violating a constraint equation. Violations occur on the rare occasion when the LHS is greater than the RHS; that is, the flow over the line could be greater than its rating if the relevant credible contingency occurs in the next five minutes.[4] A binding constraint equation affects dispatch until the constraint no longer binds.[5]

To control the flow over a bound line to avoid violating the constraint, NEMDE attempts to change the LHS inputs. For example, NEMDE may try to increase (out of merit order) the output of generators or interconnectors closer to a relevant load/demand centre ('constrain on' a generator or interconnector). By increasing generation closer to the load/demand, it can in effect reduce the congestion on the transmission system. Alternatively, NEMDE can reduce (out of merit order) the output of generators or interconnectors that are a source of the flow over the transmission line ('constrain off' a generator or interconnector). NEMDE may also adopt a combination of these actions, depending on the specific constraint equation that is binding.

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[3] If the constraint equation is not satisfied it is termed as 'violated'.

[4] Constraint equations can be expressed as LHS ≤ RHS or LHS ≥ RHS. For the purposes of this report, the descriptions of constraint equations are limited to LHS ≤ RHS. These are the most common types of constraint equations used to manage network limits.

[5] The constraint may stop binding due to for example an increase in line rating (which can be influenced by ambient weather conditions) or changes in generator offers.

While the priority is system security and avoiding violations of constraints, NEMDE still attempts to find the least cost way of dispatching generation out of the options available. Therefore if, for example, there are several generators that could be ‘constrained on’, it will choose the lowest cost combination taking into account the prices offered and the coefficients (see discussion of coefficients below). The ability of the system to change generator outputs and interconnector flows to manage network congestion is termed ‘fully co-optimised dispatch’ (see Appendix A).

When NEMDE changes flows over an interconnector (by ‘constraining on’ or ‘constraining off’ an interconnector), NEMDE changes the output of generators in adjoining region(s). This does not involve constraining particular generators, rather NEMDE reduces or increases the level of supply that is sourced from interstate generators.

Coefficients in constraint equations

As was noted earlier, the LHS of constraint equations contain all of the inputs that can be varied by NEMDE to avoid violating the constraint, such as output from generators and flow on interconnectors. Each generator or interconnector on the LHS has a coefficient, which reflects the impact it has on the constrained transmission line. In other words, the effect of a one megawatt (MW) change in the output of a particular generator (or flow on a particular interconnector) on flows over the constrained line is reflected in the coefficient assigned in the LHS. For example, if a one MW reduction in output of a generator decreases flow on the constrained line by one MW, the coefficient is +1. A positive coefficient means that a generator may be ‘constrained-off’ when the constraint binds, while a negative coefficient means a generator is ‘constrained-on’. The further away a generator or interconnector is located from the constrained line, the greater the change in output required to achieve a one MW change in flow over the constrained line. This is reflected by a smaller coefficient.[6]

There is a threshold below which it is deemed that variable inputs, including generators and interconnectors, will not be included in the LHS of constraint equations. The purpose of the threshold is to exclude those inputs, such as the output of a generator, whose variance would not materially enhance system security due to the size of their coefficient. This threshold is determined by AEMO in its *Network Constraint Formulation Guidelines*.[7] The guideline specifies that if an input has a coefficient of less than 0.07 then it will not be optimised, but its output will be taken as given (as determined by normal economic dispatch).

The threshold was determined by AEMO calculating the smallest coefficient for a generator (the relevant generator) below which a small change in the output of one generator would require an unacceptably large swing in the output of a small coefficient generator on the same constraint. No specific consideration, however, was given to interconnectors, which can change rapidly as set out below. The same threshold for generators and interconnectors was used for consistency reasons only.

[6] Note that coefficients are normalized, which means that sometimes a coefficient of 1 may not mean a 1 MW change in flows on the constrained line, but a generator or interconnector with a coefficient of 1 has the largest impact.

[7] http://www.aemo.com.au/en/Electricity/Market-and-Power-Systems/Dispatch/Constraint-Formulation-Guidelines

Technical limitations when constraining on/off

As noted earlier, when a constraint binds NEMDE tries to find the optimal outcome (which prioritises the dispatch of low priced generation) to manage the constraint. A further requirement NEMDE must incorporate is adherence to the technical limitations of the relevant generators. When submitting offers, generators have to specify the rate at which their plant can increase or decrease the level of output in MW per minute. This rate of change is referred to as the ramp rate. Generators must specify a ramp rate that is 3MW/minute or higher unless there is technical limitation on their plant.[8] An interconnector is treated as having no ramp rate and therefore NEMDE can rapidly change the level and direction of flows on interconnectors.

Disorderly bidding

Incentives for disorderly bidding

When a constraint equation binds, NEMDE dispatches constrained generators out of merit order. In other words, there will not be economic dispatch because not all low priced capacity will be dispatched, with some higher priced capacity dispatched in preference. A constrained-on generator may be dispatched at a price that is lower than the price at which it offered its capacity.[9] A constrained-off generator may be dispatched at levels that are below its desired level given the price. The desired level of output for a generator often reflects its hedge market contractual obligations. If a generator cannot generate to cover its contractual position, it risks losing significant revenue.

AEMO publishes information in pre-dispatch systems that forecasts demand levels, price outcomes and dispatch targets for generators. AEMO publishes two pre-dispatch forecasts, one on a half hourly resolution every half hour for the remainder of the trading day and a five minute pre-dispatch forecast on a five minute resolution for the next hour ahead. This enables generators to identify the likely impact of forecast binding constraints on their plant.

Generators that are forecast to be constrained have an incentive to rebid their capacity in order to limit the impact of a binding constraint on their dispatch outcomes. Generators with a negative coefficient can rebid capacity into higher price bands and/or as unavailable to reduce the possibility (or the magnitude) of an increase in output as a result of being constrained-on.[10] Generators with a positive coefficient can rebid capacity into negative price bands to reduce the extent to which their dispatch levels will be decreased. As NEMDE is seeking to manage the constraint most optimally (based on generator offer prices as a proxy for cost), rebidding capacity in this way will influence NEMDE’s outputs.

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[8] The minimum ramp rate for generators with a capacity less than 100MW is equivalent to 3 per cent of capacity per minute. This rule requirement followed a rule change proposal from the AER in 2008 (the Rule became effective from January 2009). Prior to this rule change, generators were able to offer or rebid ramp rates as low as 1 MW per minute. The level of 3 MW per minute was chosen as a compromise between the maximum technically possible and the minimum of zero.

[9] Under clause 3.9.7(a) of the Electricity Rules, the dispatch offer of a generator that is ‘constrained-on’ may not be taken into consideration when determining the dispatch price for the relevant dispatch interval.

[10] If a constrained-on generator is bid unavailable AEMO can direct the generator on to assist with managing security. This occurs rarely, but in this case the directed generator is compensated based on costs incurred.

Generators can also rebid to change their technical parameters such as ramp rates to limit the rate and extent to which their existing output levels can be decreased or increased. Generators with a negative coefficient can rebid to reduce the 'ramp up' rate to reduce the possibility (or the magnitude) of an increase in output as a result of being constrained-on. Generators with a positive coefficient can rebid to reduce the 'ramp down' rate to reduce the extent to which their dispatch levels would be decreased. When generators rebid their ramp rate, NEMDE may have to constrain other generators or interconnectors in order to satisfy the constraint.

This type of bidding, when the network is constrained, is referred to as 'disorderly bidding'. By engaging in disorderly bidding, generators are seeking to influence what outcomes NEMDE will choose to manage the constraint.

Impacts of disorderly bidding on generators and price

Disorderly bidding can serve to increase the number of generators that have to be constrained in order to manage the constraint. Where generators that are closest to the constraint (those that have the largest coefficient and therefore have the greatest impact on relieving the constraint) engage in disorderly bidding, NEMDE may have to constrain generators and interconnectors that are further away from the constraint to a greater extent than what it would otherwise have done. Remote generators and interconnectors with smaller coefficients are constrained to a greater extent than generators closest to the constraint in order to achieve the same outcome.

Disorderly bidding can also increase price volatility in the affected region(s). When a constraint binds, regional prices can increase rapidly as NEMDE dispatches higher cost generation to prevent violating the constraint. In situations where constrained-off generators rebid capacity to negative price bands to increase dispatch, the price can drop to negative levels when the constraint ceases to bind (due to the large quantity of capacity shifted to negative prices).

Disorderly bidding can then initially lead to spot prices significantly higher than that forecast, with some peaking generators having insufficient time to react to ensure they are dispatched to cover their contractual obligations, and then the price can fall significantly.

Impacts of disorderly bidding on interconnector flows

Congestion can also cause counter-price flows on interconnectors. In the normal course of events, electricity will flow from low priced regions across interconnectors into higher price regions. Counter-price flows occur when electricity is exported from a high price region into a lower priced region in order to manage congestion. This occurs when NEMDE determines that the optimal outcome to manage congestion located in one region is to force the flow of electricity into an adjoining region. This possibility is enhanced by the fact that interconnectors have no ramp rates, which allows for the flow of electricity over interconnectors to be changed very quickly.[11]

Counter-price flow on an interconnector is commonly caused by disorderly bidding by generators close to an interconnector, which is discussed further in the *Examples of disorderly bidding* section.

[11] The rate of change for the interconnector is limited only by the aggregate ramp rate of all generators on the other side of the interconnector.

Inter-regional settlement residues

Inter-regional settlement residues occur when the prices between regions separate. Generators are paid at their regional spot price while retailers pay the spot price in their region. The difference between the price paid in the importing region (by retailers) and the price received in the exporting region (by generators), multiplied by the amount of flow across the interconnector, is called a settlement residue. The rights to these residues are auctioned by AEMO in settlement residue auctions (SRAs). (See the *Interconnector flows and SRAs* section of this report).

When a counter-price flow occurs, however, AEMO has paid out more money to the generators in the exporting region than it has received from customers/retailers in both the exporting and importing regions. This is known as negative inter-regional settlement residue. The cost of funding these negative residues falls on the relevant transmission network service provider (TNSP) in the importing region. The TNSP recovers this expense through higher network service fees.[12]

AEMO is required under the rules to use reasonable endeavours to manage the accumulation of negative inter-regional settlement residues when the accumulation reaches $100 000. This is achieved by invoking constraints on interconnectors to limit or 'clamp' exports from the high priced exporting region into adjoining region(s). At times this is ineffective (with counter-price flows continuing to occur) as power system security (the management of network elements and generator technical parameters such as ramp rates) takes precedence over the management of counter-price flows. Even when clamping is successful and counter-price flows are reduced to zero, there are market inefficiencies as there are zero imports into the high priced region, which means that the return to SRA unit holders is zero.

[12] The proceeds of SRAs are paid to TNSPs, which then reduces the transmission use of system (TUOS) payments charged to the TNSP's customers. Negative settlement residues reduce the SRA proceeds that otherwise offset TUOS payments.

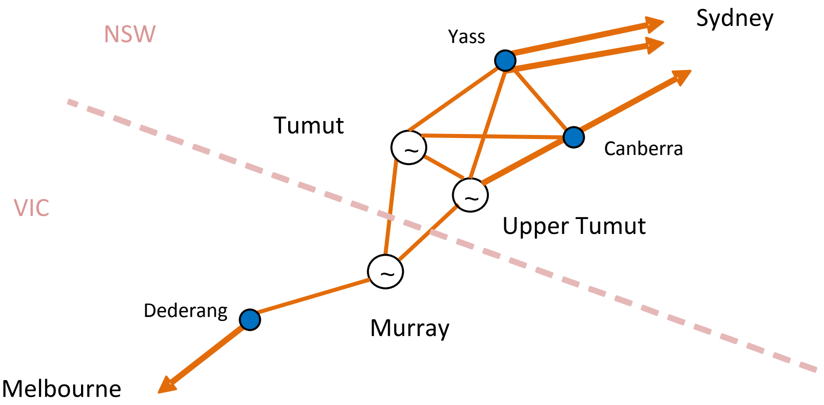
Examples of disorderly bidding

Congestion around Snowy – counter price flows into Victoria or New South Wales

The Snowy situation is one example of how disorderly bidding by participants in response to constraints can materially impact on spot price outcomes and interconnector flows between New South Wales and Victoria.

Snowy Hydro owns and operates a number of hydroelectric power stations, including Murray, Tumut and Upper Tumut, which straddle either side of the Victoria – New South Wales region boundary. Murray is located in the Victorian region, while the Upper Tumut and Tumut generators are located in the New South Wales region. Murray's pathway to major Victorian load/demand centres is southwards on the Murray-Dederang 330 kV transmission lines. Tumut and Upper Tumut are linked to major New South Wales load/demand centres northwards by three main transmission pathways. This is illustrated in Figure 1.

Figure 1: Simplified transmission network around the Snowy generators



The Murray and Tumut generators have a combined maximum summer rating of just under 4000 MW. Due to their size and position, the Murray and Tumut power stations effectively act as gatekeepers for cross border flows, in that their output strongly influences the direction of flow between New South Wales and Victoria. During periods where transmission lines between the Snowy generators and Melbourne or Sydney load centres are constrained, Snowy Hydro has the ability to rebid the capacity of its Murray and Tumut generators, to maximise its own dispatch. However, this often causes the counter-price flow of electricity from the high-price region into the low-priced region. Other generators close to Snowy Hydro, in particular Origin Energy's Uranquinty station, also contribute to counter-price flows into Victoria. [13]

Two recent examples reported in AER weekly reports of counter-price flows into Victoria and into New South Wales are outlined below.[14] However, these are not isolated examples, with 20 similar occasions since December 2009 when disorderly bidding by Snowy Hydro has led to significant counter-priced flows between Victoria and New South Wales.

[13] Uranquinty is located, in an electrical sense, very close to the Tumut generator.

[14] The AER is required under the Electricity Rules to determine whether there is a significant variation between the forecast spot price published by AEMO and the actual spot price and, if there is a variation, why the variation occurred. The AER publishes weekly reports that provide this analysis. Further information is provided when the spot price exceeds three times the weekly average and is above $250/MWh or less than -$100/MWh.

16 October 2012 – counter price flows into Victoria

An example of counter-price flows from New South Wales into Victoria occurred on 16 October 2012. At 5.05 am constraints to manage the planned outage of the 330 kV Dapto to Marulan line in New South Wales were invoked.[15] The Dapto to Marulan line is between the Sydney load centre and the southern New South Wales generators (including the Tumut generators). This meant that to manage the network constraint, the southern generators needed to be reduced in output and/or the VIC-NSW interconnector needed to flow southwards.

At 1.58 pm, rebidding by generators in New South Wales saw the forecast price for 3.30 pm to 5 pm increase from around $60/MWh to $290/MWh. Following the increase in the forecast price, Snowy Hydro and then Origin Energy rebid over 3100 MW, the total capacity of generation in southern New South Wales, to prices near the price floor:

- Over 8 rebids between 2.12 pm and 3.49 pm a total of 2520 MW of capacity at Tumut, Upper Tumut and Guthega (another Snowy Hydro generator in the region) was shifted by Snowy Hydro from prices above zero to close to the price floor. This resulted in the start up of the Tumut generator, which was generating 1800 MW by 4 pm. The rebid at 2.46 pm also reduced the 'ramp down' rate of the three stations to the minimum allowed of 3 MW/min. The rebids were effective immediately. The reasons given for the rebids related to congestion on the Dapto to Marulan line.

- Following the very large rebids into negative prices by Snowy, NEMDE forecasts showed a significant reduction in the output of all four Uranquinty generators, which were already running at full output. Origin Energy rebid 240 MW and 664 MW of capacity at Shoalhaven and Uranquinty, respectively, from prices above $47/MWh to close to the price floor. This resulted in the start up of the Shoalhaven generator, which was generating 240 MW by 3.25 pm. The rebids were effective from 3.05 pm and 3.10 pm and the reason given related to management of the congestion on the Dapto to Marulan line.

At 2.50 pm the constraint managing the planned outages bound. The large negative rebids for the Snowy Hydro and Origin Energy generators saw the output from their generators increase by 1200 MW and 200 MW respectively. As a result the flow across the Victoria to New South Wales interconnector changed from imports of 706 MW into New South Wales to forced counter-price exports by 3.10 pm, reaching 875 MW into Victoria by 3.25 pm.

To manage (or 'clamp') the accrual of negative residues as a result of the counter price flows AEMO invoked a further constraint. This commenced reducing flows into Victoria from 3.50 pm, with flows reaching zero by 4.20 pm. This required the output from a number of generators south of the constraint to reduce:

- Tumut (Snowy Hydro), which commenced generating at 2.10 pm and reached 1800 MW at 3.30 pm, reduced from 1797 MW to 1760 MW (at 3 MW per min);

- Upper Tumut (Snowy Hydro) reduced from 652 MW to 577 MW (at 3 MW per min);

- Guthega (Snowy Hydro) reduced from 53 MW to zero (at 3 MW per min);

- Uranquinty (Origin Energy) reduced from 644 MW to 461 MW;

[15] The 330 kV Liddell to Tomago line was also taken out of service at the same time. This outage had a minor impact on flows from Queensland to New South Wales, reducing imports into New South Wales.

- Shoalhaven (Origin Energy), which commenced generating at 3.10 pm and reached 244 MW at 3.30 pm, reduced to 202 MW. At 4.05 pm Origin Energy rebid to reduce the ramp down rate to zero, which meant that its dispatch could not be reduced. The reason given was that it could not be further reduced as it had reached its technical minimum; and
- the Woodlawn and Gunning wind farms were shut down from 10 MW and 53 MW.

There were 27 New South Wales 5-minute prices above $250/MWh between 3 pm and 5.30 pm and around $90 000 of negative settlement residues across the New South Wales to Victoria interconnector accrued over the period. This is only one recent example. There are many examples where the impacts were far more significant outlined in Table 1.

11 September 2012 – counter price flows into New South Wales

Snowy Hydro can engage in similar bidding behaviour at its Murray power station in Victoria that results in counter-price flow into New South Wales. Snowy Hydro engaged in such behaviour on 11 September 2012, when the spot price in Victoria exceeded $2000/MWh for the trading intervals ending 9 am and 9.30 am. The spot price in South Australia exceeded $1400/MWh for the same trading intervals.

At 8.05 am as a result of a scheduled outage of the Lower Tumut to Wagga line (just inside the New South Wales region) a group of constraints were invoked. At 8.20 am, as the line was taken out of service, the constraint to manage flows on the Murray to Dederang lines (towards Melbourne) bound. Given its proximity to the Murray-Dederang line, the Murray generator has the greatest direct impact on flows on the line, reflected in its +1 coefficient. This means that reduced output from Murray assists managing the constraint on a one-for-one basis. The VIC to NSW interconnector has a coefficient of minus 1. This means that flows from Victoria towards New South Wales also assists with managing the constraint on a one-for-one basis.

At 8.43 am, Snowy Hydro rebid the entirety of its offered capacity at Murray of 1437 MW from prices above $30/MWh to zero to take effect for the dispatch interval ending 8.50 am. One minute later, Snowy Hydro rebid the ramp down rate for the Murray generators, reducing it from 50MW/minute to 3MW/minute, to take effect from the 8.55 am dispatch interval. The reason provided for the rebid was to avoid Murray being constrained off.

At 8.49 am, effective from 9 am, AGL rebid 270 MW of capacity at Eildon and McKay from prices below $74/MWh to above $12 700/MWh. Following this rebid, the dispatch price in Victoria increased from $73/MWh at 8.55 am to $12 890/MWh at 9 am (the price in South Australia also increased from $72/MWh to $9602/MWh).

As a result of Snowy Hydro rebidding its capacity to a price of zero, Murray's dispatch was increased from 900 MW at 8.45 am to 1437 MW at 8.50 am.[16] The combination of Murray's increase in output and the constraint on the Murray to Dederang lines caused the flows from Victoria to New South Wales to increase significantly from 181 MW at 8.45 am to 724 MW at 8.50 am.

These flows were counter price on the Vic-NSW interconnector, which saw negative settlement residues of around $1.1 million accrued in one hour. At 9.10 am a constraint that was invoked by AEMO to 'clamp' the accrual of negative settlement residues was violated as Murray could not be ramped down quickly enough to cease the counter-price flows.

[16] Murray has a ramp up rate of 200 MW per minute, but at the same time had the minimum allowable ramp down rate of 3 MW per minute.

Counter-price flows between Victoria and New South Wales

These very recent events are examples of the disorderly bidding as a result of network congestion that, on 20 occasions since December 2009, has led to significant counter-priced flows between Victoria and New South Wales. Tables 1 and 2 list each event where disorderly bidding led to more than $150 000 in negative settlement residues into New South Wales and into Victoria respectively. The tables outline for each event the maximum counter price flow, the maximum price in the higher priced region and the negative settlement residues that accrued.

Table 1: Summary of high cost recent examples of counter price flow into New South Wales

Date	Maximum spot price	Maximum counter price flow (MW)	Negative settlement residue
9/02/2010	$7847	560	$1 150 342
10/02/2010	$1489	497	$717 410
21/04/2010	$2093	496	$1 143 255
22/04/2010	$9999	641	$17 490 818
21/06/2010	$1756	894	$258 606
22/10/2010	$2470	1108	$982 967
28/11/2010	$115	1417	$156 831
31/01/2011	$9597	174	$439 729
30/05/2011	$1814	1039	$1 032 369
31/05/2011	$166	908	$225 632
2/07/2012	$4364	126	$172 325
11/09/2012	$2221	769	$1 324 546
Total			**$25 094 829**

Table 2: Summary of high cost recent examples of counter price flow into Victoria[17]

Date	Maximum spot price	Maximum counter price flow (MW)	Negative settlement residue
7/12/2009	$7715	37	$230 066
22/01/2010	$4514	205	$214 457
4/02/2010	$5541	1365	$5 025 392
11/02/2010	$1998	152	$173 259
26/03/2010	$1836	226	$205 485
13/04/2010	$3081	529	$804 754
29/06/2010	$4987	194	$471 903
9/11/2011	$6498	685	$1 733 523
Total			**$8 858 839**

[17] The 16 October 2012 event is not included as negative settlement residues were less than $150 000.

As is discussed later, the negative settlement residues are only one aspect of the inefficiencies that arise from disorderly bidding. There are larger impacts in terms of non-economic dispatch and through increasing the risk profile of all NEM participants, both customers and generators.

Congestion in Queensland around Gladstone – counter price flows into NSW

Congestion associated with the transmission lines between Calvale-Wurdong and Calvale-Stanwell has seen highly volatile prices in Queensland and significant negative settlement residues during 2011 and 2012. These outcomes have occurred during both high demand and moderate demand periods in Queensland. The AER considers that step changes in the dynamic line ratings for the relevant lines, significant disorderly bidding and the inclusion of the Queensland to New South Wales (QNI) interconnector with a small coefficient in the relevant constraint equations are key contributing factors.

The constraints at the centre of the issue are:

- Q>>NIL_855_871, which is designed to prevent the Calvale-Wurdong line from overloading should the Calvale-Stanwell line trip/fail; and
- Q>>NIL_871_855, which is designed to prevent the Calvale-Stanwell line from overloading should the Calvale-Wurdong line trip/fail.

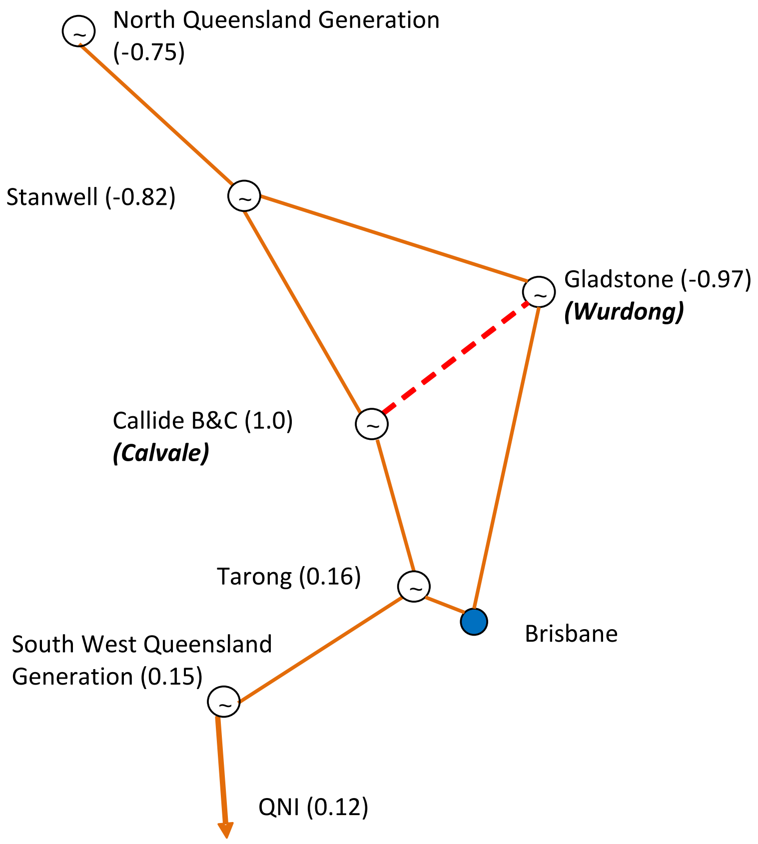
The constraint to manage the Calvale-Wurdong line binds more frequently than for the Calvale-Stanwell line, so this analysis will concentrate on the former. (Although the impacts of the two constraints are very similar). Figure 2 is a simplified representation of the transmission network around Gladstone in Queensland. The Calvale-Wurdong line is represented by the red dashed line. There are four key generators situated close to the Calvale-Wurdong and Calvale-Stanwell lines: Callide B, Callide C, Gladstone and Stanwell.

The majority of Queensland generators and flows on the QNI interconnector can influence the flows on the Calvale-Wurdong line. Included in Figure 2 are the relevant coefficients for generation stations and the QNI interconnector according to the Q>>NIL_855_871 constraint.

As the closest generators, Callide and Gladstone have the largest coefficients, followed by Stanwell. In general, power flows in a northerly direction from Callide towards Gladstone. The direction of the power flow means that if flows on the line have reached the limit it is necessary to increase or ‘constrain-on’ the Gladstone generators (with a -0.97 coefficient) and the Stanwell generators (-0.82 coefficient) and reduce or ‘constrain-off’ the Callide generators (1.0 coefficient). However, the amount and rate at which a generator is constrained on or off is limited by the offered availability and ramp rate of those generators.

The generators located in northern Queensland have the next highest coefficients. The majority of these generators are small capacity, fast-start peaking plant. The larger generators in south-west Queensland and QNI have lower coefficients due to their distance from the constraint. If the maximum constraining on or off of the Callide, Gladstone and Stanwell generators is reached (for example, due to low generator ramp rates), then other generators and the interconnector will need to be constrained on or constrained off. However, the smaller coefficients associated with these other generators and the interconnector means that there needs to be a larger change to dispatch to manage flows to the same degree.

Figure 2: Simplified transmission network around Gladstone



Background on dynamic transmission line ratings and Queensland generation ownership

In July 2011 the Queensland government restructured ownership and operation of its generating assets. In this restructure, Gladstone Power Station was transferred from Stanwell to CS Energy. CS Energy also owned Callide B and half of Callide C. The Tarong Power Stations (near Brisbane) were transferred to Stanwell Corporation.[18]

In 2011, Powerlink, the Queensland TNSP, implemented "dynamic" ratings on the Calvale-Wurdong and Calvale-Stanwell lines. This means that local weather conditions are used to determine the rating of the line. The introduction of dynamic ratings is usually beneficial for congestion as the maximum dynamic ratings for a line are often higher than the static rating (which assumes worst case weather conditions). In the case of the Calvale-Wurdong and Calvale-Stanwell lines, the introduction of dynamic ratings has generally increased the rating from around 800 MVA to in excess of 900 MVA. However, dynamic ratings of lines can fluctuate according to weather conditions, including wind speed and direction.[19] Step reductions in ratings as a result of a change in wind speed for example can cause the relevant constraints to bind at short notice.

[18] An earlier version of this report incorrectly stated that Wivenhoe was transferred to Stanwell Corporation. Wivenhoe was transferred to CS Energy.

[19] The thermal rating of a transmission line is influenced by weather conditions because airflow across a conductor can cool it and allow a higher power flow. Therefore ambient temperature, wind speed and wind direction (air flow across the conductor provides more cooling than along the conductor) can alter the maximum safe power flow.

Binding Calvale constraints, disorderly bidding and counter-price flows

Since July 2011 there were 24 occasions when the constraints used to manage overloading of the Calvale-Wurdong (and/or Calvale-Stanwell lines) have bound and led to significant counter-price flows into New South Wales. Congestion on these lines has been triggered on each occasion by a combination of changes in the dynamic ratings of the line and/or rebidding of the Gladstone or Callide stations by CS Energy.

As a result of the restructure of generation in Queensland, CS Energy operates the power stations which are located on either end of the Calvale-Wurdong line (Gladstone and Callide power stations). CS Energy can contribute to causing the constraint to bind by increasing the northerly flow on the line. It can do this by increasing output at Callide, reducing output at Gladstone (which also results in more northerly flow across the line) or both. A generator can change its likely dispatch level by changing the offer price, so CS Energy can increase the flow on the Calvale-Wurdong line by rebidding capacity at Callide into lower prices or by rebidding Gladstone into high prices. If the change in offer price is accompanied with a high ramp rate then the change in dispatch level can be quite rapid. This can then cause the constraint to bind, leading to the constraining on or constraining off of generators and QNI.

As noted earlier, if the constraint binds economic dispatch is interrupted. NEMDE attempts to avoid the constraint violating by constraining on and off generators, however, NEMDE still finds the lowest cost way of dispatching generation based on the generator bids. This means that if the offer prices of Gladstone increase significantly then NEMDE will dispatch other generators in preference even though Gladstone has a large coefficient (i.e. it doesn't need to shift output very much to relieve the constraint). This means the outputs from generators or flows over QNI are changed by a large amount.

It was also noted earlier that the ability for the constraint to be managed by changing the dispatch of a generator depends on the ramp rate offered for that generator. At times CS Energy has been rebidding to reduce Callide's ramp down rates so that when the constraint binds Callide can only be decreased at a slow rate (3 MW/min). After Gladstone, the next highest coefficient generators are then dispatched at their ramp rates. The next highest coefficients are for Stanwell Power Station, which is generally 'ramped up' (at 60 MW per 5 minutes), and the smaller northern generators (which are generally constrained-on, requiring the generators to start up, but often rebid as unavailable to avoid uneconomic dispatch).

This is not, however, sufficient to satisfy the constraint. Therefore low priced generation in south west Queensland is also reduced. Southerly flows across QNI into New South Wales also assist in managing the loading on the line. However, the lower coefficients for the south west Queensland generators and QNI mean that the magnitude of the southerly changes are very large – for example QNI must be changed by 8 MW (1/0.12) for every 1 MW that Callide does not change.

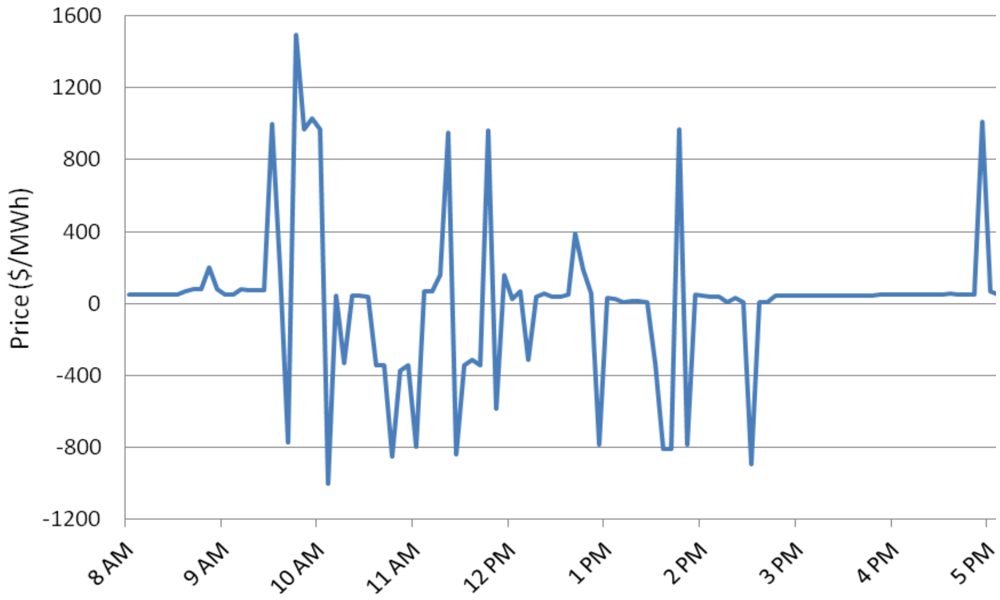
The reduction in the dispatch of low priced south west Queensland generation and dispatch of high priced capacity at Gladstone leads to a high Queensland spot price. Flows on QNI change, with flows being forced south (counter-price), and negative settlement residues accrue. These high price outcomes often occur for only one or two dispatch intervals until Stanwell's (lower-priced) generation ramps up sufficiently to be dispatched, relieving the constraint.

Price volatility in Queensland

The bidding behaviour of participants in response to the binding constraints has contributed to a significant amount of price volatility in Queensland. For example between January and March this year, Queensland spot prices exceeded $100/MWh 72 times (with two prices above $2000/MWh), and sixteen negative spot prices (including three below -$100/MWh) followed these high prices.

As illustrated by the events of 25 August, the dispatch prices can fluctuate from very high prices to the price floor. In Figure 3 it can be seen that between 9 am and 2.30 pm (and for a further dispatch interval at 4.55 pm), Queensland 5-minute prices were extremely volatile, fluctuating between $1493/MWh and -$1000/MWh. The 5-minute price exceeded $900/MWh on nine occasions and fell below -$300/MWh on 21 occasions.

Figure 3: Five-minute Queensland prices on 25 August 2012



Such volatility can lead to market uncertainty and cause inefficient dispatch of generation. It also makes it more difficult and expensive for retailers and generators to hedge against volatility. These market conditions can deter new retail entry and new generation investment.

Constraint formulation

Fully co-optimised constraints have been used for all constraint formulations since mid 2004 (as detailed in Appendix A). The outcomes discussed above, including the accrual of negative settlement residues, are symptomatic of the use of fully co-optimised constraints under certain conditions. One of the factors AEMO took into consideration in specifying the smallest coefficient on a fully optimised constraint at 0.07 was to prevent significant swings for the relevant input. Nevertheless there have been large step changes in flows over the QNI interconnector as a result of disorderly bidding associated with congestion around the Gladstone region. In its May 2012 report on congestion issues in Queensland, AEMO acknowledged an alternative to the current arrangements would be for interconnectors to have a different threshold than other variables.[20] AEMO considered that in doing so, the relevant constraint equation would require a larger operating margin – i.e. would have to bind

[20] See http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Market-Event-Reports/NEM-Operations-Review-Queensland-Summer-2012-855-871-Congestion

at a lower level – to ensure that system security was maintained. Fully co-optimised constraints are discussed in more detail in Appendix A.

Recent accrual of negative settlement residues

Table 3 lists each event where congestion in the Gladstone region and disorderly bidding led to more than $150 000 in negative settlement residues into New South Wales. The table outlines for each event the maximum counter price flow, the maximum price in the higher priced region and the negative settlement residues that accrued.

Table 3: Significant counter price flows related to congestion around Gladstone

Date	Maximum spot price	Maximum counter price flow (MW)	Negative settlement residue
5/09/2011	$2117	569	$371 303
12/01/2012	$1757	917	$992 763
15/01/2012	$228	1148	$183 147
27/01/2012	$509	966	$302 697
29/01/2012	$2080	1257	$1 271 630
14/02/2012	$360	876	$221 795
20/02/2012	$503	667	$184 699
21/02/2012	$392	1004	$195 922
22/02/2012	$438	772	$255 562
2/03/2012	$317	872	$307 724
3/03/2012	$265	854	$271 734
4/03/2012	$339	491	$165 025
5/03/2012	$289	1155	$247 736
6/03/2012	$268	898	$201 920
9/03/2012	$260	1079	$278 325
10/03/2012	$196	1118	$233 506
23/03/2012	$396	969	$297 466
25/08/2012	$646	785	$346 152
30/08/2012	$463	900	$178 514
31/08/2012	$311	1147	$301 895
1/09/2012	$603	1078	$293 140
3/09/2012	$370	1112	$511 862
8/09/2012	$408	978	$245 893
27/10/2012	$1085	1034	$433 501
Total			**$8 293 909**

As was noted earlier, negative settlement residues are only one aspect of the inefficiencies that arise from disorderly bidding.

Interconnector flows and SRAs

Interconnection of the regions of the NEM via the transmission network allows regions with tight supply/demand balances to import low priced electricity, reducing the need to dispatch high priced capacity within the region. This interconnection benefits customers/retailers through lower wholesale energy costs and enables generators with spare capacity to generate more electricity than they otherwise would, leading to the more efficient use of generation assets and a reduction in the ability of local generators to exercise market power. The effective operation of interconnectors plays a significant role in facilitating interregional trade and competition, to the benefit of market participants and end users of electricity.

As illustrated by the *Congestion in Queensland around Gladstone* section of this report, physical or security limitations of interconnectors are not the only factors that influence the amount of energy that can flow over the interconnector. Constraint equations designed to manage flows over other parts of the transmission network utilise interconnector flows as a variable input. As demonstrated by the events in Queensland, flows over an interconnector that is located a significant distance away from the relevant transmission line can be significantly impacted as a result of disorderly bidding and the constraint formulation.

Risk management and hedging

The reduction in flows over an interconnector as a result of disorderly bidding causes inefficient pricing and generation outcomes in affected regions. Counter-price flows impose significant costs on TNSPs. In addition, counter-price flows impact on the value of holding SRA units.[21] One of the reasons that market participants purchase SRA units is to facilitate inter-regional hedging. Inter-regional hedging facilitates competition between generators in different regions and is efficiency enhancing as customers/retailers can hedge for less cost. Inter-regional hedging occurs when a party enters into a hedge contract with a counterparty located in another region of the NEM. The terms of hedge contracts are usually struck with reference to the spot price of a specified region. The counterparty that is located in a different region of the NEM is exposed to the risk of price separation between the regions. Where significant divergence between the two spot prices occurs, one party bears the risk of the price difference. Purchasing a sufficient amount of SRA units to match the hedge contract quantity and capture the price difference between regions is one way to mitigate that risk.

When the flows over an interconnector from a low priced region into a high priced region are constrained due to disorderly bidding, the amount of inter-regional settlement residues that accrue (the price difference multiplied by the energy that flowed) is reduced. As settlement residues are divided equally amongst SRA unit holders, this means that unit holders receive a lower than expected return for the price difference between the two regions for the relevant trading intervals. When counter-price flows occur, the value to SRA unit holders is zero.[22]

SRA units for interconnector flows during a specified quarter are auctioned in advance. The number of units sold for an interconnector direction is set with reference to the nominal capability of the interconnector. The price which bidders are prepared to pay is informed by an assessment of the

[21] Inter-regional settlement residues are allocated to holders of SRA units on a pro rata basis. If a participant has purchased 100 MW of SRAs out of a possible 1200 then it would receive one-twelfth of the inter-regional settlement residues that accrue on that interconnector for every trading interval (provided the residue is positive). SRAs are sold for each quarter of the year.

[22] If counter-price flows occur, then negative inter-regional settlement residues will accrue. Under rule changes which commenced in July 2010, the TNSP in the importing region is responsible for funding negative inter-regional settlement residues.

potential price divergence between two adjacent regions during the relevant quarter and an assessment of the level of average flows over the interconnector during periods of high prices.

The variability of average flows over interconnectors during periods of high price divergence between regions since 2009 is demonstrated by Table 4. The table shows for each of the 2009-10 to 2011-12 financial years (and the first four months of 2012-13) the number of trading intervals when spot prices in one region are at least $100/MWh higher than the neighbouring region and, of those intervals, the number when the interconnector flowed counter-price. The table also shows average inter-regional flows during these high priced periods. It also shows for comparison the quantity of settlement residue units available for purchase in the settlement residue auction. If the average flow is negative then, on average, flows have been counter-price. In these cases the value of the SRA units will be low.

Table 4: Imports across the major interconnectors during high price periods since 2009

Relative regional spot prices	Number of trading intervals (number of counter price flow intervals)				Average flow (MW)				Available SRA units
	2009-10	2010-11	2011-12	2012-13 YTD	2009-10	2010-11	2011-12	2012-13 YTD	
$\text{Qld}_{\$}$>$\text{NSW}_{\$}$	41 (9)	19 (19)	60 (48)	17 (17)	27	-255	-255	-415	550
$\text{NSW}_{\$}$>$\text{Qld}_{\$}$	131 (24)	63 (2)	5 (0)	20 (0)	193	459	299	444	1200
$\text{NSW}_{\$}$>$\text{Vic}_{\$}$	172 (23)	108 (3)	6 (2)	5 (4)	221	396	96	-92	1500
$\text{Vic}_{\$}$>$\text{NSW}_{\$}$	69 (27)	9 (9)	1 (0)	6 (4)	59	-260	52	-67	1300
$\text{SA}_{\$}$>$\text{Vic}_{\$}$	110 (1)	34 (0)	27 (2)	9(1)	179	207	176	112	700

The table analyses interconnector metered flows for trading intervals where neighbouring region prices differ by more than $100/MWh. Figures for 2012/13 current as at 14 November 2012.

SRA firmness

Disorderly bidding during high price events has had a significant impact on New South Wales to Queensland flows and flows between Victoria and New South Wales. This is demonstrated by Table 4 which shows that when prices in Queensland were higher than prices in New South Wales (19+60+17 or 96 trading intervals), interconnector flows have been predominantly counter-price since 2010-11 (19+48+17 or 84 trading intervals), reflected in a negative average flow (255, 255 and 415 MW south, which is counter price). The majority of these counter-price flows have occurred during times of congestion around Gladstone in central Queensland. This means that the utility of SRAs to manage high Queensland prices is severely diminished. The negative settlement residues that accrued during high priced periods associated with central Queensland congestion are detailed in Table 3.

In contrast, during the same period when New South Wales prices were high there were rarely counter-price flows from Queensland, with positive average interconnector flows (however, still well below the 1200 MW of SRA units sold). However, there were lower average flows from Queensland into New South Wales during 2009/10 due to significant counter-priced flows (24 out of 131 high priced trading intervals). These counter-price flows related to disorderly bidding associated with congestion caused by TransGrid's large scale upgrade of the transmission network west of Sydney.[23]

[23] The AER published a number of $5000 reports covering these events, including the 7 December 2009 event when rebidding by Snowy into low prices at Tumut and Upper Tumut led to counter-price flows into Victoria.

Disorderly bidding by Snowy Hydro has at times led to counter-price flows both northwards and southwards between Victoria and New South Wales, although to a lesser extent than for the New South Wales to Queensland interconnector. Table 4 shows that although there were few occasions when the price in Victoria was higher than New South Wales (69+9+1+6 or 85 trading intervals) a high proportion of the time flows were counter price (9 out of 9 in 2010-11 and 4 out of 6 so far this financial year).

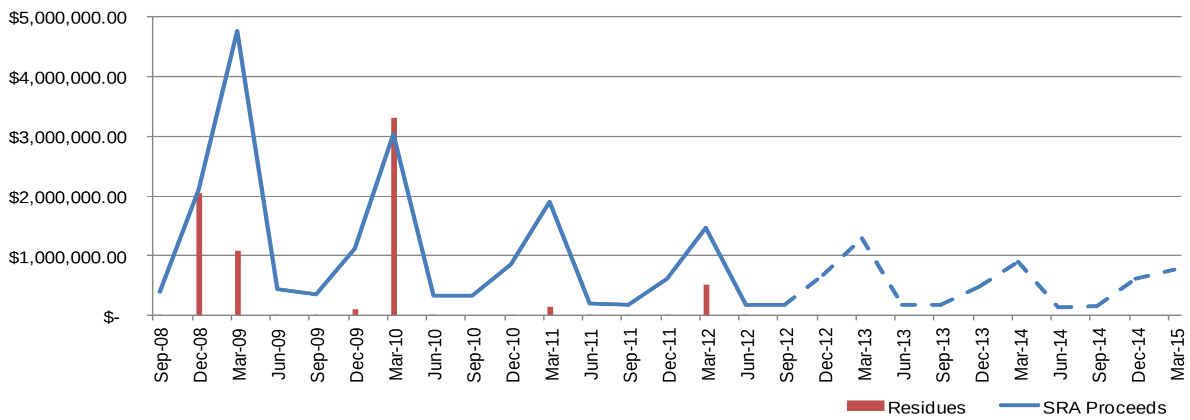
The effect of disorderly bidding on interconnector flows and settlement residues is difficult to predict. As a consequence of the uncertainty, the price that market participants are willing to pay for SRA units can be affected.

The AER considers that the recent significant reduction in utility of settlement residues as a result of 'disorderly bidding' has seen a noticeable reduction in the SRA proceeds, reflecting the reduced market valuation of this mechanism. This is evident from Figure 4, which shows quarterly auction proceeds as a blue line for New South Wales to Queensland settlement residues and, with estimated proceeds for future quarters (based on tranches already sold) as a dashed blue line. A possible indicator of the auction value is the historical quarterly settlement residues, which are shown as red columns.

It is possible that expectations of lower demand and low prices have influenced future SRA proceeds. However, as noted earlier, the value of inter-regional settlement residues is determined by the price difference and the interconnector flows. The AER believes the potential for extreme price differences in the summer periods going forward is not likely to diminish materially, as this is driven by infrequent extreme demand (as a result of high temperatures in south east Queensland or tight supply conditions). Therefore the AER considers that the reduced market valuation is primarily caused by an expectation of reduced interconnector flows and counter-price flows during price differential events.

Figure 4 shows that for New South Wales to Queensland flows the SRA proceeds have fallen and are projected to continue to fall – consistent with the increasing prevalence of counter-price flows.

Figure 4: New South Wales to Queensland quarterly SRA proceeds and residues



It should be noted that New South Wales to Queensland flows have had the most significant decline in SRA proceeds. However, the forecast proceeds for the interconnectors between Victoria and New South Wales are also declining for both directions; the AER considers that disorderly bidding by Snowy Hydro is a contributing factor.

Summary of impacts

The AER has observed an increased prevalence of disorderly bidding associated with network congestion in the last three years. Disorderly bidding has a detrimental impact on the efficient operation of the NEM through increased price volatility, inefficient dispatch and reduced inter-regional trade. While it is extremely difficult to quantify the impacts of disorderly bidding, the AER does consider that the costs of disorderly bidding, such as counter-price flows, have risen with the increase in frequency. The AER considers that a number of factors have contributed to disorderly bidding including constraint formulation, generation ownership changes, the abolition of the Snowy region as well as network issues.

The NEM, being an energy only market, relies on efficient price signals to encourage and reward investment in generation. Interconnectors provide an important facilitator in the NEM by allowing excess low cost generation in a neighbouring region to supply into a region where tighter supply conditions result in high spot prices. Customers pay for the shared transmission network as they benefit from improved efficiency in dispatch of low cost generation. Generators are not, however, obligated to offer to the market at cost. NEMDE considers generator offers as a proxy for cost, which means that negative offers that arise through disorderly bidding and are not reflective of generator costs are dispatched, which can lead to inefficient dispatch and counter-price flows.

While the out of merit order dispatch is a significant cost inefficiency in and of itself, the AER also considers price volatility associated with disorderly bidding is an additional source of inefficiency. High prices driven by congestion can distort the price signals to trigger new investment in generation, as well as potentially reducing the return on existing generation assets. Price volatility also adds to the risk profile of retailers/customers, which increases costs through the supply chain. The extent to which to this price volatility can be managed through SRAs is also affected by disorderly bidding.

The AER considers that disorderly bidding has a detrimental impact on SRA firmness by reducing interconnector flows. In this regard, the effect of disorderly bidding can be two-fold in that the bidding has caused the high prices in the first instance while simultaneously reducing the protection of SRAs by reducing interconnector flows. That is, disorderly bidding has created the risk that SRAs are designed to manage, whilst simultaneously reducing the value of that risk management tool. The AER considers that the reduction of firmness of SRA units imposes potential long term costs on market participants and end users. Inter-regional hedging can play a significant role in ensuring that there is a competitive tension between generators. The effectiveness of inter-regional hedging is, however, dependent on the firmness of SRA units in mitigating the risk of price separation between regions.

In addition, end users may have to pay higher network tariffs than what they otherwise would have absent the conduct. TNSPs receive the proceeds from SRA auctions, which go to offset the TUOS fees TNSPs charge end users. When negative settlement residues accrue, the TNSP in the importing region is required to fund the shortfall, which is sourced from end users. Where disorderly bidding affects the value of SRA units, TNSPs receive lower proceeds from SRA auctions. Accordingly, disorderly bidding reduces the extent to which SRA proceeds offset TUOS fees.

Conclusion

Over the last three years in particular the increasing prevalence of disorderly bidding has created unnecessary price volatility, led to inefficient dispatch and created counter price flows across interconnectors. As a result the ability for market participants to manage risk across interconnectors has reduced and with it competition between regions. This has been most prevalent between Queensland, New South Wales and Victoria. The market design incentivises disorderly bidding by generators when faced with being constrained. Network constraints can occur anywhere in the NEM and accordingly any interconnector, not just QNI and VIC-NSW, is at risk of counter price flows precipitated by disorderly bidding.

The AEMC's *Transmission Frameworks Review* has recommended changes to the settlement of generators that are located at mispriced connection points and engage in disorderly bidding through its Optional Firm Access (OFA) proposal. The AER welcomes the AEMC's work to develop the OFA proposal. It aims to address a range of important issues, including increasing the firmness of interconnector availability, in order to improve energy contract liquidity and competition. While the AEMC has made significant progress, there are many important areas of detail that are yet to be developed. The success of the model will, in part, lie in the detail.

As the AEMC is tackling a range of very complex issues, it is likely that any reforms will take a long time to implement. Therefore, the AER considers that, given the significant and pressing issues associated with disorderly bidding and counter-price interconnector flows, fast-tracked changes should be implemented in the short term to at least partially address the problem. One option would be to introduce a simplified congestion management mechanism via relatively straightforward changes to AEMO's settlement systems. This could, in effect, be a stepping stone towards the full OFA model. A congestion management mechanism would deliver significant gains. In particular, it could address much of the disorderly bidding problem, which would have flow on effects in terms of improving interconnector flows and the firmness of inter-regional hedges. Alternatives may include a greater restriction on generators lowering their ramp rates. At the moment, generators must specify a ramp rate that is 3MW/minute or higher unless there is technical limitation on their plant. For large generators this is a very low ramp rate. For example, Snowy Hydro's Tumut facility is treated as a single unit by NEMDE and has a capacity of 1800 MW. If it is operating at its maximum capacity of 1800 MW, (which it can reach from zero in less than 10 minutes with its ramp up rate of 200 MW/min) and bids in a 3MW/minute ramp down rate, it will take 10 hours to ramp down to zero output. Changing the rules so that generators must specify a ramp-rate of at least a certain percentage (say 3 per cent) of their capacity would significantly lower the inefficiencies caused by disorderly bidding. There may be alternatives, such as restrictions on bidding into negative prices during times of congestion, which could also assist.

The AER also recommends that AEMO commence reviewing the constraint formulation guidelines to assess whether a minimum threshold should be applied to determine if interconnectors are co-optimised. This could prevent rapid changes in interconnector dispatch outcomes that result from network congestion that is remote from the interconnector. Such a change would assist somewhat in addressing the Queensland to New South Wales flow issues discussed in this report. However, it would not solve counter price flows between Victoria and New South Wales that occur as a result of disorderly bidding by Snowy Hydro, as the VIC-NSW interconnector has a high coefficient. (In other words, because the VIC-NSW interconnector will always have a high coefficient, changing the minimum threshold will not alter the constraint equation).

A Background on the full co-optimisation of network constraints

In late 2000, the commissioning of the Queensland to New South Wales interconnector (QNI) created the first situation where management of joint inter-regional and intra-regional network flows had the potential to become a significant issue.

To pursue a solution a Network Constraints Reference Group was established in April 2001. This group published an options paper in January 2002 indicating that the then National Electricity Market Management Company (NEMMCO), now the AEMO, preferred an Option 4 formulation where both inter-regional and intra-regional flows were co-optimised according to the generator offers.

Following further consultation and the granting of a derogation under the then National Electricity Code (now the National Electricity Rules), from July 2004, NEMMCO began to adopt the fully co-optimised constraint formulation for all constraint equations. In this formulation, all terms (both generators and interconnectors) are placed on the left hand side of the constraint equation and therefore may be directly controlled by the NEMDE. Having direct control of as many of the variables in the dispatch process as possible allows AEMO to achieve a more optimal dispatch of all possible control variables and thereby improves AEMO’s ability to manage system security, with flow on benefits of reduced safety margins in network constraint equations.

In May 2005, the Ministerial Council on Energy (MCE) endorsed NEMMCO’s formal adoption of the fully co-optimised constraint formulation. Formalising the requirement that NEMMCO use the fully co-optimised constraint formulation was also endorsed by most market participants as part of the consultation process for the AEMC’s Congestion Management Review (CMR). The CMR Final Report (published in June 2008) recommended that the constraint formulation be formalised in Chapter 3 of the Rules. The Rule commenced on 1 September 2009.

A risk with fully optimised constraints is that they can lead to counter-priced flows and therefore inter-regional settlement deficits if remote intra-regional generation is offered at a lower price than a neighbouring region. This can occur when generators are constrained and rebid to the price floor – which has come to be known as disorderly bidding. This in turn leads to AEMO to intervene to manage excessive accumulation of negative residues by clamping interconnectors. At times this is ineffective (with counter-price flows continuing to occur) as power system security (the management of network elements and generator technical parameters such as ramp rates) takes precedence over the management of counter-price flows. Even when clamping is successful, however, and counter-price flows are reduced to zero, there are zero imports into the high priced region, which means that the return to SRA unit holders is zero.