NATIONAL GENERATORS FORUM

27 March 2014

Mr John Pierce
Chairman
Australian Energy Market Commission
Submitted through AEMC Website
Reference: ERC0165

Dear Mr Pierce

Rule Change Consultation: National Electricity Amendment (Generator ramp rates and dispatch inflexibility in bidding) Rule 2014.

The National Generators Forum (NGF) welcomes the opportunity to provide feedback on the above rule change proposed by the Australian Energy Regulator (AER) in relation to ramp rates and dispatch inflexibility profiles ("FSIP").

The NGF strongly disagrees with the AER's assessment of how its Rule change would promote the National Electricity Objective (NEO).

The proposed rule change shows no benefit to the NEO and does not address the real issue which is congestion caused by the reduction in the capability of the transmission network.

The proposed rule change if implemented would significantly increase compliance cost, remove market incentives for investment in ramping capability and potentially impact on the efficiency of the contract markets. Overall the NGF believes there would be a net decrease in economic efficiency and hence the rule change proposal should be rejected.

Yours sincerely

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Summary of the NGF's submission

The NGF submits that the rule change proposed by the AER in relation to ramp rates and dispatch inflexibility profiles ("FSIP") should be rejected. The proposed rule change shows no benefit to the NEO and does not address the real issue which is congestion caused by the reduction in the capability of the transmission network.

In relation to ramp rates the AER has not adequately quantified the problem, and therefore the costs and the benefits have not been properly identified.

The proposal fails to:

- separate the effect of ramp rates compared to rebidding volumes into different prices;
- separate the effect of aggregated units compared to ramp rates for all units;
- identify the economic inefficiencies caused by rebidding ramp rates, often citing price effects (transfers of wealth) rather than net improvements in efficiency; and
- understand the long term costs associated with expropriating supply from producers rather than relying on market incentives .

In relation to FSIP the AER has provided little information to support the change other than a desire for consistency in the treatment of "technical" parameters in bids. While the NGF submission has focussed primarily on ramp rates our arguments against ramps rates being a technical parameter can similarly be applied to FSIP.

The NGF reiterates that while thoughtful regulation can improve the industry for both participants and consumers, applying broad reaching regulatory change to address niche and "pet" issues can often create more problems than it solves. The NGF contends that providing market incentives to drive desired behaviour is likely to be more beneficial than regulatory intervention.

The NGF strongly disagrees with the AER's assessment of how its Rule change would promote the NEO:

1. System security

The AER claim that restricting the commercial use of ramp rates in rebidding will improve system security as AEMO will violate system security constraints prior to violating "technical" bid parameters.

We show in the submission that the proposed rule change would have very little impact on the number of constraints which are violated and therefore would have little if any impact on enhancing system security. The NGF also note that AEMO retains the ability to direct participants to alter their output regardless of bids in order to maintain system security if required.

2. Occurrence of counter-price flows

The NGF submission shows that the root cause of counter-price flows is the occurrence of multiple and non-credible transmission outages which significantly reduce the capability of the transmission network. As a result of this exogenous risk, which generators have no control, participants manage this exposure through the bidding process which has been inappropriately demonised as "disorderly" bidding.

The NGF contends the focus must instead shift to TNSPs who are responsible for planning and implementing the network outages and the AER who is responsible for the regulatory incentive schemes associated with these network outages..

3. Wholesale spot price volatility

The NGF submission explains how constraints are formulated; how they affect the RRP; how unexpected RRPs can ensue and the relative importance of ramp rates.
The submission explains that that wholesale price volatility is the direct result of:

- the design of constraints, constrained prices and the subsequent implementation of negative settlement residue constraints; or

- in the presence of network outages, generators being unable to offer prices below the local price (and are constrained off) and/or generators being unable to offer prices above the local price (and are constrained on); but
- not ramp rates

The NGF uses periods highlighted by the AER to make these points.

The submission explains the Rule change could concentrate congestion risk onto the generator closest to the sending end of the constraint with the highest ramp rate, but *only* when the constraint does *not* affect interconnectors and calculation of the RRP.

4. Deadweight loss from increased compliance cost

The NGF submission explains the proposed rule change would place significant burden on market participants, resulting deadweight loss.

5. Perverse incentives

The NGF submission raises concerns that by expropriating ramping capability (and thus devaluing it), in the long run the market will not provide it. Inequitable treatment of flexible units (backed off further by constraints during market events) creates a market disincentive for investors to provide flexibility into the market. This will not be in the consumers' interest.

6. Adverse impacts on the Contract markets

The NGF submission explains the Rule change would concentrate congestion risk, for constraints where the generator cannot price below the interconnectors, onto the generator closest to the sending end that is most flexible. This may deter forward contracting.

7. Issues should be considered as part of the Optional Firm Access Project

The issues being considered in this Rule proposal are identical to those being assessed as part of the Optional Firm Access project. While the NGF does not support the OFA we acknowledge that at least there is a reasonable assessment process which would attempt to holistically consider the impact of the OFA on all aspects of the Spot and Contract markets. The NGF strongly asserts that this ramp rate rule change is rejected and instead assessed as a subset of the OFA project.

NATIONAL GENERATORS FORUM

RESPONSE TO THE

AEMC’S CONSULTATION ON THE AER’S RAMP RATE AND FSIP RULE CHANGE

March 2014

Executive Summary

This response to the AEMC's consultation on the AER's Ramp rate and FSIP Rule change:

The Rule described by the AER fails to:

- separate the effect of ramp rates compared to rebidding volumes into different prices;
- separate the effect of aggregated units compared to ramp rates for all units;
- identify the economic inefficiencies caused by rebidding ramp rates, often citing "price effects" (transfers of wealth) rather than net improvements in efficiency; and
- understand the long term costs associated with expropriating supply from producers rather than relying on market incentives .

- Even if it was efficient to remove these "price effects" (which we do not agree with), the Rule change proposal does not do so.

- The **intent**, but **not the application**, of the AER's proposal force producers to "subsidise" the operating cost of a transmission constraint, by removing the "price effects":
  - This is poor policy because to force the wrong party to pay for the costs of another (in this case the transmission monopoly) will not incentivise the party causing the cost to avoid them.

- The proposal will not remove "price effects" (residues) as it fails to understand generator rebidding of ramp rates is a **low order** of consequence, not a "second order" as stated by the proponent.
  - The example box 5.2 suggests to the layman that all a generator need do to be dispatched at a high price is reduce ramp rate – it is just not that simple.
  - For price effects it is imperative that interconnectors are included in constraint equations and therefore ramp rates become less important in the setting of price.

- However the application of the Rule change could:
  - concentrate congestion risk onto the generator closest to the sending end of the constraint with the highest ramp rate, but *only* when the constraint does *not* affect interconnectors and calculation of the RRP.

- The AER has highlighted Q1 2013 and 25th August 2012 in QLD as periods that justifies the Rule change proposal. We have investigated these and also January 2011 and 25th-26th August 2012.

- We have categorised pricing outcomes, and rather than ramp rate limitations, show that price effects, rather than ramp rates, are as a result of either:
  - The design of constraints with resulting in constrained prices and the implementation of negative settlement residue constraints; or
  - Generators unable to offer prices below the local price (and are constrained off) and start to set price with other offers that are also constrained.

- The AER is highlighting productive efficiency losses from a "perfect" merit order dispatch, which will not be provided by the NEM.
  - Rather than the dispatch process, productive efficiency is largely "locked-in" by the sale and trade in forwards and futures.
  - Come dispatch the NEM helps to schedule the cheapest units, but does not guarantee it, especially at times of higher demand and greater risk.
- If the AER wants "merit-order dispatch" it should propose a rule change that reverts to a central dispatch process where an engineer decides the most productively efficient dispatch.

Question 1

(a) Does the current minimum required ramp rate of 3 MW/minute hinder AEMO's ability to determine an economically efficient dispatch arrangement while maintaining system security?

No, the 3MW/min was developed by AEMO; the NEM has no problems with system security. We note AEMO can direct participants at any time to change dispatch rather than rely on the market dispatch should there be risk of an insecure operating state.

(b) If so, would the AER's proposed rule improve the economic efficiency of the dispatch process in this regard?

This is an odd question. Isn't economic efficiency in markets the result of competition driving down costs to efficient levels, based on the demand for that service? We cannot see how economic efficiency is improved in any way by a Regulator subverting market incentives for ramping capability and unit flexibility.

(c) What evidence is there that system security has been compromised by ramp rate limitations?

The AER has provided no evidence that system security has been compromised by ramp rate limitations – their analysis is based solely on prices. The AER appears to be conflating price effects and system security issues. It is not helpful in the consideration of this Rule change proposal as to conflate the costs and benefits confuses the issue. Also, the NGF is unsure as to whether the "problem" is whether it is all units that can rebid ramp rates to 3MW/min or only aggregated units.

The NGF notes the AER recognition that generator ramp rates have a higher constraint violation penalty (CVP) compared to the thermal ratings of transmission equipment. This, however, does not imply the secure operation of the NEM is threatened when there are multiple binding constraints in a dispatch interval and the constraint with the lower CVP, for example a thermal constraint, is violated. Transmission equipment have continual and 15 minute peak ratings so where a thermal constraint is violated it may be the continual rating that is violated and not the peak rating. In addition equations can have operating margins. On this basis there is no evidence that system security has been compromised by ramp rates, even if a constraint equation has violated.

There has been no indication that AEMO have changed their view on minimum ramp rates since the original rule change in 2009. At that time, the AER noted that NEMMCO formed an opinion that 3MW/Min should accommodate the vast majority of system security issues. The NGF also note that AEMO retains the ability to direct participants to alter their output (regardless of bids) in order to maintain system security if required.

The table below shows that the number of NEM constraint violations has been consistently decreasing in recent years. Last year there were less than 3000 incidences of violated constraints. Please note that from 2012 AEMO started separately identifying negative residue management constraint equations as "NRM" when previously they were included in "#".

		2009	2010	2011	2012	2013	Total	
Violations (# DI)	**All**	**19501**	**9247**	**7916**	**5074**	**2932**	**44670**	100%
Bids/Inflex	$	17088	7207	5785	3178	1366	34624	78%
Quick/Control Room	#	1080	1231	1351	1205	563	5430	12%
Quick/Control Room	@	0	0	0	0	2	2	0%
Constraint Automation	C	168	36	23	18	15	260	1%
Non Conformance	NC	156	49	21	29	37	292	1%
Residue Management	NRM	0	0	0	52	13	65	0%
FCAS	F	100	48	208	93	120	569	1%
Other/Energy	N/Q/S/T/V	909	676	528	499	816	3428	8%

The greatest proportion of violated constraints "#" are of a lower order than system security. Some are even designed to violated, such as soft ramping constraints for interconnectors. The constraints which ensure system security, "F" and "N/Q/S/T/V" are rarely violated.

Question 2

(a) Do you agree with the AER's assessment of the costs associated with counter-price flows?

The AER's analysis of negative settlement residues does not include the positive residues caused by the NRM constraint equations of AEMO. These have been significant and are a prime cause to the volatility in prices and we shall show the price effects of these equations in this response.

The AEMC Final Report on the management of negative inter-regional settlements residues (IRSRs) "are a relatively minor component of the overall price of electricity paid by consumers" with the AER over stating the cost of counter-price flows. In the summary of high cost examples in Appendix B the figures are misleading with around $19 million of the $26 million cost is attributable to a single market event in NSW with around $5 million or around $9 million in Victoria also attributable to a single market event.

Note:

- For NSW over 21-22 April 2010 there were concurrent outages on the Sheffield to Georgetown 220kV line, Dederang to South Morang 330kV line and the Heywood Moorabool 500kV lines separating Victoria from adjoining regions causing a reduction in interconnector limits on Basslink (0MW) the Vic NSW and Heywood Interconnector.
- These outages would not occur now due to the development of the Service Target Performance Incentive Scheme
- For Vic over 4 February 2010 the constraints causing the market event have been eased with some associated constraints only binding for a few hours over the past few year due to the commissioning of the 500kV upgrade for the 300kV network west of Sydney and increasing the thermal rating on the No. 70 330kV Mt Piper Wallerawang line.

(b) To what extent is generator rebidding a cause of counter-price flows on interconnectors? Is this primarily due to generators' ramp rates or other forms of bidding behaviour?

Box 5.2 is simplistic. It gives the impression that generators have more control over dispatch than they presently do.

A better way to consider constraints and the factors that affect dispatch, flows across interconnectors and prices is first to identify some terms and definitions:

- **Offer price**: the price from a generator for 1MW of dispatch over an hour;
- The NEM dispatch engine's **objective function**[1] (**NEMDE**) calculates a cost of dispatching the cheapest offers (sum of Dispatch MW x $/MW);
- The regional reference price (**RRP**) is the difference in cost (to the cost of dispatch) if 1MW more (a "***marginal MW***") is also dispatched;
- **Marginal Value** of constraint is the difference in the cost of resolving dispatch if 1MW more of flow is allowed on the circuit compared to the constraint limit;
- **Constraint equation** usually formulated as **LHS <= RHS** is used in dispatch to limit the dispatch of generators or interconnectors, which are includes in the LHS of equation;
- Constraint equations typically limit the flow on a circuit to ensure if another circuit trips the "**post contingent flow**" the remaining circuit, will not exceed the **rating** (equipment limit) therefore we should describe the topography of constraint as:
- **Sending end** of constraint – "pushing with" – decrease in MWs reduces post contingent flow
- **Receiving end** of constraint – "pushing against" – increase in MWs reduces post contingent flow
- **Constraint Coefficient** – ratio between the change in dispatch of generator or interconnector on the flow on circuit compared to other generator or interconnectors, scaled where the highest coefficient equals 1[2];
    - Coefficients are positive for sending end if the constraint is formulated as LHS <= RHS, negative for receiving end
- **Scaling Factor** – ratio of change of dispatch of constraint coefficients to post contingent flow
- **Operating Margin** – an allowance in the constraint equation safety buffer;

[1] Expressed as a value or "cost" that needs to be maximised under the Rules

[2] For example if a generator closest to the constraint is dispatched and 50% of its dispatch goes on the constrained circuit, it will have a factor of 1, if another has 25% of its dispatch it will have 0.5 and so on

- **RHS equation** works out **headroom** of circuit by taking the rating, deducting both the flow (on line now) and the flow to be added to circuit on loss of other circuit, multiples it by the Scaling Factor to relate it to the generators and interconnector coefficients
- **Local marginal price** = constraint coefficient x marginal value of constraint; and
- **Ramp rates** are the limitation rate of change of offered volume

To be dispatched a producer must offer prices below the local price. The local price is lowest at the sending end of the constrained circuit and highest at the receiving end. The locations on the network closer to the sending end or receiving end are gradually lower or higher than the RRP depending on how close they are to the constraint (reflected by the constraint coefficient.

This depends on offer prices by generators at different locations on either the sending or receiving end (which is reflected in the marginal value of the constraint) and close to the sending end the price is low and at the receiving end high.

The NEM has a price cap of $13,100/MWh and -$1,000/MWh. The affect on generators is that sometimes they cannot price lower than or higher than the local price and will be constrained off or on whatever price they offer. Because of the asymmetry between the floor and cap generators tend to get constrained off. Important to this is the relationship between coefficients of the generators in the constraint, their offer prices and the floor/cap price. If a generator on the sending end prices down to -$1,000/MWh this means in order to dispatch the -$1,000/MWh price the NEMDE may need to constrain on another generator (or interconnector) with a different constraint coefficient – the cost of these other generators, when adjusted by the coefficient may be greater than the -$1,000/MWh and the negatively priced generator is constrained off.

The NEM has regional prices; this means generators in adjacent regions are priced by proxy through the interconnector and the other regions' cleared price. Depending on the price of the interconnector, the constraint coefficient and the offer prices of other generators in the constraint equation, the interconnector or generator in the constraint equation may be constrained on or off. In many instances, but not all, the prices behind the interconnector, are not low enough to ensure the interconnector is dispatched.

Factors that dictate whether a generator on the sending end of a constraint is dispatched:

1. Generator's Constraint Coefficient and marginal value of constraint (local price)
2. Whether interconnectors are included in the equation
3. Whether Region 2 RRP is lower than local price for interconnector
4. Whether the interconnector hits a ramping limit (limit not set by the constraint equation, but possibly by another, even a negative settlement residue constraint)
5. Ramp rate of generator

The example box 5.2 suggests to the layman that all a generator need do to be dispatched at a high price is reduce ramp rate – it is just not that simple. There are other factors that have to be accounted for first, constraint coefficients, the formulation of the constraint and other potential equations that may be introduced to NEMDE before the ramp rate is important.

The AEMC and AER have defined the issue of Ramp Rates as being a "*second order effect*" (page 21 of consultation paper) that "may prolong the effect" of rebidding volumes to different price bands.

The NGF's view is that the rebidding of ramp rates is a **low order effect** in the management of counter price flows and negative settlement residues **when the constraint equation includes interconnectors**. It is of a higher order for constraints that do not, but these, as we shall show in answer to your questions are not important for price effects (counter price flows) as they tend not to effect prices and flows.

We shall discuss how ramp rates are relatively unimportant with regards to price volatility at times of network constraints. We shall also discuss that ramp rates are rather more important and very useful as a risk management tool for generator participants to manage transmission outage risk when the generator(s) included in constraints that do not include interconnectors in the constraint equation.

Question 3

(a) Is it valid to conclude that changes in the merit order of dispatch results in productive efficiency losses?

No. The analysis is flawed and shows little understanding of how the NEM works in practice. The NEM stands for National Electricity Market. The important term is "Market" whereby producers and consumers are expected to trade in a competitive market environment and producers (and consumers if they are also producers), decide whether they dispatch their units through the offer of electricity derivative contracts and subsequently offer prices to AEMO in the physical market; this is opposed to an engineer deciding which producers are dispatched depending on the optimum short run cost. The competitive pressures of the market should ensure that, in both the shorter and longer term the cheapest producers are scheduled and dispatched, through the calculation of an efficient price. This is not the same as ensuring the cheapest producers are running at any one time.

Due to the disposition of assets, the forward trading of derivative contracts; and different expectations of future prices (electricity, gas , coal) the actual dispatch of producers may not be the most productively efficient, but the price determined from fierce competition in the sale of derivatives and subsequent dispatch in the NEM will be lead to efficient outcomes overall.

The trade in electricity futures and forwards effectively dictates the efficiency of physical dispatch in the NEM. This is because, at times of high demand, there is a strong incentive for producers to either increase or reduce supply to a volume close to their derivatives position to reduce potential losses or maximise potential profits. This has been termed economic withholding[3] whereby the quantity sold is lower, but the price higher, resulting in greater profits. Due to these financial positions, the physical dispatch in the NEM on a day to day basis may not be productively efficient, but over the longer term due to prices determined by this competition, they should be. Temporary productive inefficiencies should not be construed as a problem with the market design as they will be resolved through the competitive process.

The AER in its Rule Change Proposal[4] cited congestion around Gladstone as being one of the reasons for them proposing the Rule change. It also asserted that generators' rebidding of ramp rates results in productive inefficiencies by causing higher cost plant to be dispatched instead of lower cost plant.

If we consider an example, would an engineer have dispatched the Braemar units and Mt Stuart peaking generators ahead of Gladstone Power Station? The answer is no, yet the NEM did exactly that when it allocated, through the sale and purchase of, derivative positions to participants in Queensland. This leads us onto the Q1 2013 in Queensland example given by the AER as justification for this Rule change.

The QLD market had been characterised by extremely low power prices and derivative prices for a number of years due to subdued demand and increased supply, especially in peaking and intermediate assets, owned by the larger retail companies. Previous summer periods had shown that the larger retailers would use their peaking and intermediate generation assets to reduce price volatility by increasing supply possibly below fuel cost, in order to reduce costs on their retail expenses (settled on the low pool price). The market for derivatives in QLD was bearish for summer 2013, with contract prices below the long-run cost of operating a base-load power station. Baseload generators found themselves exposed to the pool price for a significant proportion of their capacity as no one had been willing to buy electricity forwards and futures at a reasonable price. As a result this competitive dynamic Gladstone and Tarong power stations were largely withdrawn from the market in Q1 2013, resulting in a tighter supply and demand balance in the region.

With Gladstone withdrawn to low generation levels a constraint in central Queensland emerged, whereby the flow on the Calvale-Wurdong circuit had to be limited to ensure there was no post contingent overload from the trip to the Calvale-Stanwell circuit (or vice-versa).

Please note the emerging constraint (northerly flows) had been clearly identified by Powerlink well in advance and the constraint, (arising from the low dispatch of Gladstone), could have been more effectively and efficiently managed by Powerlink utilising a network support agreement or simply someone buying swaps[5] from Participants (which would have the same effect).

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[3] The AEMC has previously discussed the exercise of transient market power in imperfect markets

[4] AER Submission, Possible options for interim solutions to congestion-related disorderly bidding, P1

[5] Please note some power markets do allow the market operator to enter into forward transactions to balance the system, with these sometimes being financial derivatives transactions

What followed was productive inefficiency with peaking generators owned by some participants being dispatched when another participant withdrew baseload capacity (due to the NEM's incentives for them to do so). This was seen when a retailer-generator exposed to the spot price (due to retail load greater than generation) ran a peaking generator with a high cost, at low offer prices. This phenomenon occurs in the NEM because the mix of generating capacity owned by each participant is imperfect, as are competitive strategies often "locked in" in advance, so productive inefficiencies follow. This is a normal feature of any market which does not have a perfect mix of capital stock and competitors. Markets are always in a state of flux and the competitive dynamic may have been a feature of a market where expectations of future demand and prices had been incorrect. It was certainly true that there was an inefficient level of capital (in this case excess of supply); placed in this situation participants may compete to try to impose losses on others by seeking to increase or reduce the price depending on their potential exposure.

So what happened in Q1 2013 was virulent competition between participants. The market in futures had expected very low prices because of significant oversupply, subdued demand and the tactic of retailers dispatching their own peaking generators. The forward and futures market did not price in the risks appropriately and buyers and sellers remained exposed to the spot price.

What actually happened was higher than expected demand, a reduction in baseload capacity (Tarong and Gladstone) and a local transmission constraint. (Please note that the local transmission constraint, and rebidding in response to the constraint, may have served to depress prices in some instances, which we shall explain later). Prices were higher than expected because of these factors – but were they the result of a generators ability to rebid ramp rates? The answer is no.

To summarise, the AER is highlighting productive efficiency losses from a "perfect" merit order dispatch, which will not be provided by the NEM. Rather than the dispatch process, productive efficiency is largely "locked-in" by the sale and trade in forwards and futures. Come dispatch the NEM helps to schedule the cheapest units, but does not guarantee it. Market conditions, including transmission constraints, which may only arise because of "locked-in" productive inefficiencies, can change competitive dispatch from "merit-order" dispatch.

If the AER wants "merit-order dispatch" it should propose a rule change that reverts to a central dispatch process where an engineer decides the most productive dispatch.

(b) Is there a difference in productive inefficiencies caused by the rebidding of ramp rates and other forms of bidding behaviour?

This focus on productive inefficiency, by the AER in this Rule Change proposal and the AEMC and Productivity Commission (in the Transmission Frameworks Review and Inquiry into Network Regulation respectively), often citing the inefficiencies caused by "disorderly" rebidding, is unhelpful.

The National Electricity Objective will not be served if regulators compare actual dispatch results of the market to what would be dispatched by an engineer. Instead of an engineer running an algorithm and dispatching plant we have market forces at play, price discovery, commercial strategies and most important the discipline of profit and loss, dictating what is efficient. Sometimes it will look inefficient, incoherent, or to coin a phrase "disorderly", but this just competition at play.

There is no particular productive inefficiency in the lowering of ramp rates to 3MW/min by producers. Just as with repricing volumes to the market price cap, this is solely a low order commercial norm to manage risk with the other producers in the market.

(c) Assuming productive efficiency losses can be caused by other forms of rebidding, would the AER's proposed rule reduce the extent of productive efficiency losses?

If the NGF really believed the AER's assertions, which we do not, the only productive inefficiencies that will be reduced of a **low order of consequence**.

If we cite the example of Q1 2013, would the restrictions on the rebidding of ramp rates have stopped Tarong mothballing two units, Gladstone placing 3 units on reserve? Would it have stopped Braemars, Oakey and Mt Stuart running instead of the baseload generators? Would it have increased the sale of Q1 2013 electricity derivatives and the price of these? It would not. Productive inefficiencies from "other forms rebidding" are just a feature of competition in the market.

Question 4

(a) To what extent have participants experienced a quantifiable increase in the costs of managing wholesale market risks through higher risk premiums on hedge contracts and, if so, to what extent can this be attributed to the issues discussed above?

(b) Assuming the adoption of a prudent risk management and purchasing strategy, do these higher risk premiums represent a real and measurable cost to consumers?

Section 5.2.2 of the consultation paper highlights periods of volatile pricing following on from example box 5.3.

With regard to the question, we do not believe the prices for Q1 2013 cap contracts shown in figure 5.4 to be a result of transmission constraints and generators subsequently rebidding ramp rates. It was a result of a greater competitive dynamic explained in response to question 3. As we will explain the prices of cap contracts and the payout cannot be said to be attributable to the rebidding of ramp rates, instead attributable to risk management strategies undertaken by those participants who remained exposed to the spot price during Q1 2013 and then sought to cover this exposure through the purchase of derivatives.

Figure 5.4 which shows the price for a Q1 2013 $300/MWh "cap" contract in QLD as sold on the ASX. The cap payout during the period was $20.86/MWh as calculated from the pool prices and was largely affected by prices both during the period in mid January (explained earlier) and the very high prices as a result of ex-tropical cyclone Oswald, which did not include the constraints and peaked at $6,298.63/MWh at 17:00 on the 29th January.

The NGF believes the prices in Q1 2013 represent competition at work in the wholesale market. Prior to Q1 2013, those participants with exposure to the spot price through a retail position greater than their generation thought they could keep the price low by supplying the market with peaking assets rather than buying derivatives from base-load generators. This competitive strategy must have proved successful as it has been used for a few years (much to consumer, rather than producer interests) but failed for a short period in Q1 2013. Of course, the result of this "rugged" competition is prices in the wholesale market. These prices are a real and measurable cost to consumers (otherwise we should not have a wholesale market), but to suggests it is an additional, unnecessary burden on consumers (as suggested by the question) would be unwise.

Framework for understanding price volatility and the effect of ramp rates
To understand the effect of ramp rates on price volatility (and therefore derivatives) we provide in a critique of example box 5.3 and a framework for categorising pricing outcomes under times of transmission constraints.

The example in box 5.3 is not very useful in looking at the management of risks associated with constraints. The example has the constraint located at the RRN and generators on the other side of the constraint connected to the RRN. With all the generators connected to the RRN, all will have the same impact on the constraint, using the terminology used before they will have the same "constraint coefficient" of 1. A real example would have a number of generators on the sending end and some on the receiving end with some other loads and probably a "meshed "network with some parallel circuits. For the purposes of any analysis you can't allocate all the generators with the same coefficient.

For some reason the example in box 5.3 suggests prices will be volatile; that very high prices will be followed by low prices when the constraint "unbinds" and negative offers are cleared. For some reason it does not include interconnectors. We find it difficult to draw any conclusions from this example box given there doesn't seem to be any reason why there would be any volatile prices.

B, C and C could be constrained off. D or E need to set the price. Simple as that, nothing more – why should the constrained volumes at the sending of the constraint magically set price? If they are offering prices at the floor -$1,000/MWh it is likely they will be fully dispatched and cannot set the price, constrained or not.

It is our view the example is deliberately confected to try make a point about volatile pricing. As with example box 5.2 it gives a misleading impression that volatile pricing is a simple occurrence.

In the example supply is constrained from generators B, C and D and then the price is set by generator A. Please note there is no requirement for generators A and E (on the receiving end) to be in the constraint equation. This is merely a function of the way AEMO tends to formulate constraints[6] and leads to complicated pricing outcomes.

The NGF believes this formulation results in an effective subsidy from generators A and E if they are constrained on at prices they do not wish to receive (prices below their offers) and don't immediately rebid offer prices higher to not be constrained on. This is because, if generators B, C and D offer prices at -$1,000/MWh to maintain dispatch and a $60 offer from either A or E is included in the RRP, in order to resolve the equation and depending on constraint coefficients, NEMDE can increase dispatch from either C or D at -$1,000/MWh.

Of course this is not a steady state because A and E will need to reprice offered volume to the Market Price Cap in order not to receive the low resultant RRP. Instead of the present formulation of constraints, which includes numerous generators on the receiving end, Generator A and E could easily remain unconstrained and be free to set the RRP at the RRN.

As for the example 5.3 of Generator E or A setting the price at the Market Price Cap, the actual price under the formulation of constraints would not simply be the Price Cap, but be set by adjusting the different generators either on the sending end, or at both ends of the constraint, in order to set the price. The example box just doesn't show how prices are set. Instead we can explain that there are three categories of pricing:

CATEGORY A – Marginal MW equation in unconstrained circumstances
CATEGORY B – Marginal MW does not affect other binding equations
CATEGORY C – Marginal MW simultaneously resolved with other binding equations

We have previously described that prices are set by the "marginal MW". The RRP is calculated by increasing demand by 1MW at the RRN. What this means is the change in generating units, interconnectors, plus any change in losses must equal 1MW. NEMDE must simultaneously resolve the marginal MW with all others, such as Ramp rates, interconnector limit equations, fixed loads, non-conformance and transmission constraint equations.

The three categories show the impact on the RRP of transmission constraint equations when they (or do not) need to be simultaneously resolved with the marginal MW equation.

Categories A and B produce largely the same outcomes. These conditions arise frequently.

CATEGORY A – marginal MW equation in unconstrained circumstances
In this category no other transmission constraints are binding. NEMDE can set a price by calculating the cost of 1MW for Region 1 by dispatching another generator in any region, for example a cheap generator in Region 2: this means positive (1MW exports) from Region 2, which is then loss adjusted. This can increase or reduce flow on the interconnectors, depending on whether it is importing or exporting. If exporting, the losses will increase and the price in Region 1 will be greater than 2. If importing, losses will reduce and the price in Region 1 will be less than 2.

Key to understanding this category is realising counter intuitive outcomes arise – i.e. upon face value you would expect the higher price to be the importing region price but if the flow is priced as a loss adjusted down generator's price in the importing region (Region2) then the price in Region 1 will be lower as it will reduce losses on the interconnector.

In this category there is no transmission constraint affecting dispatch.

CATEGORY B – marginal MW does not affect other binding equations
In this category other transmission constraints are binding, but the marginal MW can be supplied by an unconstrained generator which can set the price. For instance a constraint equation may have only two units on the LHS (constrained) and all others remain unconstrained. In satisfying the marginal MW, and setting price NEMDE does not need to source the MW from the two units on the LHS, but will source the MW from one that is unconstrained. The marginal MW from the unconstrained generator makes no difference to the local constraint equation which remains satisfied with the dispatch of constrained generators being equal to the limit.

The marginal value of the constraint equation limiting the generation of the two units will be the price of the units constrained when compared to the price of that providing the marginal MW. If the generators on the LHS

[6] AEMO includes all disputable units that have an effect on the flow of the circuit of 7%, relative to the dispatchable unit that has the highest affect

disorderly rebid to -$1,000/MWh (or $13,100/MWh when constrained up) then these marginal values can be significant, but they have no direct affect on the marginal MW equation setting the price, bar the exclusion of the two units from potentially setting the price.

The ramp rate is important in distributing dispatch between participants that have already priced to -$1,000/MWh. In this category the transmission constraint is affecting dispatch, but not price.

CATEGORY C – marginal MW simultaneously resolved with other binding equations
Because AEMO includes numerous terms, both at the sending and receiving end of the constraint equation, it is often the case, when ramp rate, availability and other constraints are included that upon the introduction of a constraint equation all generators and interconnectors in a region are constrained. This means, in calculating the RRP any generator or interconnector adjusted to provide the marginal MW requires other units to be adjusted to satisfy the constraint equation.

As all units will have a different constraint coefficient when providing the marginal MW, NEMDE can simultaneously resolve both the marginal MW and constraint equations by changing dispatch of units that have a different coefficient. For example, if generator D has a coefficient of 0.5 and generator B a coefficient of 1, NEMDE can decrease B by 1MW and increase D by 2MW. By doing so the marginal MW is satisfied (we have 1MW more) and the constraint equation is satisfied (we have no greater post-contingent flow on the affected circuit). The price in this instance is affected by the change in dispatch of the units included in the constraint as these units are providing the marginal MW. If these units are priced at -$1,000/MWh, the price will be -$1,000/MWh. Please note this is unlikely because generator D would likely be fully dispatched.

In this category the transmission constraint is affecting dispatch and price.

Understanding these three categories is important to the consideration of risks associated with transmission constraints, price volatility and participant behaviour (volume volatility). It also allows us to understand the relative importance of ramping constraints to this price and volume volatility.

Now, let's consider some particular instances where there was volatile pricing due to constraints. The volatility in price is usually as a result of either:

1. The design of constraints with category C prices and the implementation of negative settlement residue constraints
2. Generators unable to offer prices below the local price (and are constrained off) and start to set category C prices with other offers

Two particular periods of volatile pricing have been in QLD. One period was the week after the January 2011 floods of the Lockyer, Bremer and Brisbane rivers in Queensland which included the flooding of the Rocklea transmission substation. Another is the Q1 2013 period of hot weather in January 2013, coupled with the Calvale-Wurdong/Stanwell constraint. Please note this period of interest is prior to the high prices later in Q1 2013, related to generator outages caused by the Australia day ex-cyclone Oswald.

What is important in the consideration of these events is that the volatility in prices is related to the points above rather than rebidding of ramp rates, which is a low order of consequence.

January floods

On Monday 17th January 2011 AEMO's contingency analysis indicated that the loss of either the Blackwall to South Pine (838) 275 kV line or the loss of the Mount England to South Pine (825) 275 kV line would result in an insecure operating state. A temporary constraint set was created by the Control Room and therefore did not follow the equation naming guidelines.

- **#QLD1_E_20110117**: Multiple QLD1 LHS <= 4100 (Wt = 20)

This equation constrained down generation from SEQ and/or restricted interconnector flows from NSW (positive flow, exports). When NEMDE calculates the dispatch targets for the interconnectors and generators included in an equation, this is known as "optimising".

A feature of the equation was that when it bound it removes all the generators from the LHS from setting the spot price in QLD (all in SEQ) and reduces positive flow on the interconnectors, thus leading to price separation between NSW-QLD RRNs. This enabled unconstrained generators to set the QLD price (CQ and FNQ), to a level higher than the NSW price.

The manual equation (#QLD1_E_20110117) was quickly superseded by a new multiple outage constraint set using fully co-optimised network constraint formulations (invoked at 1535 hrs). The new equation (Q>>X_809_8818_832_1) co-optimised all QLD generation and positive flow on the interconnectors (NSW to QLD), rather than just generation from SEQ.

With this being all QLD generation, rather than solely SEQ, the incentives were for all generators to disorderly rebid to -$1,000/MWh in order to prevent being constrained. This, coupled with the NSR equation #NSW1_E_20110117, resulted in NEMDE calculating price by requiring 1MW at the QLD RRN and satisfying both equations.

The category C prices resulted in NEMDE calculating the price from a decrement of units off and increment of units on, each with different coefficients resulting in how much -$1,000/MWh generation was either increased or reduced and therefore set the price. These meant prices of the order of $800-900/MWh or -$1,000/MWh were commonplace, largely dependent on the effect (volume) of equation #NSW1_E_20110117.

The following chart presents the data from the 17th Jan 2011, starting 0400. The MW combined flow (blue area) across the interconnectors is shown on the RH axis, alongside the RHS binding limit of the negative settlement residue equation #NSW1_E_20110117 (yellow line). The QLD price in $/MWh (red line) and the Negative Settlement Residues with the (light blue line, $1,000s) is shown on the LH axis. The LH axis is limited to $1,500, however on the 17th the price did increase to $12,500/MWh.

During the three DIs 1620 to 1630hrs Queensland prices reached the Market Floor Price (-$1,000/MWh, when more than 8900MW of QLD generation was offered at negative prices, compared to 8036MW at 1600. The NSR equation #NSW1_E_20110117 prevented this negatively priced energy being exported to NSW. In theory this should not happen, as the NSR equation is supposed to prevent counter price flows. AEMO may have prevented this inefficient outcome by withdrawing #NSW1_E_20110117 from NEMDE a few dispatch intervals earlier.

Figure 1 — 17th January 2011: flow, prices, limits and settlement residues

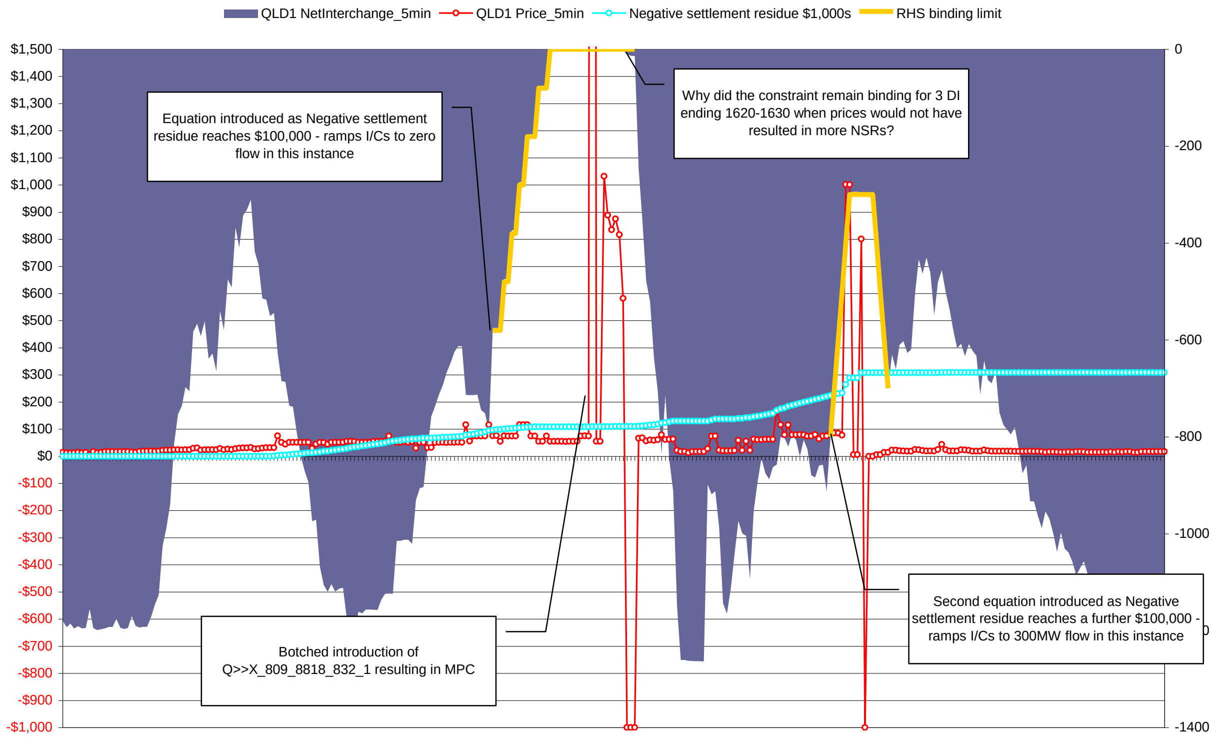
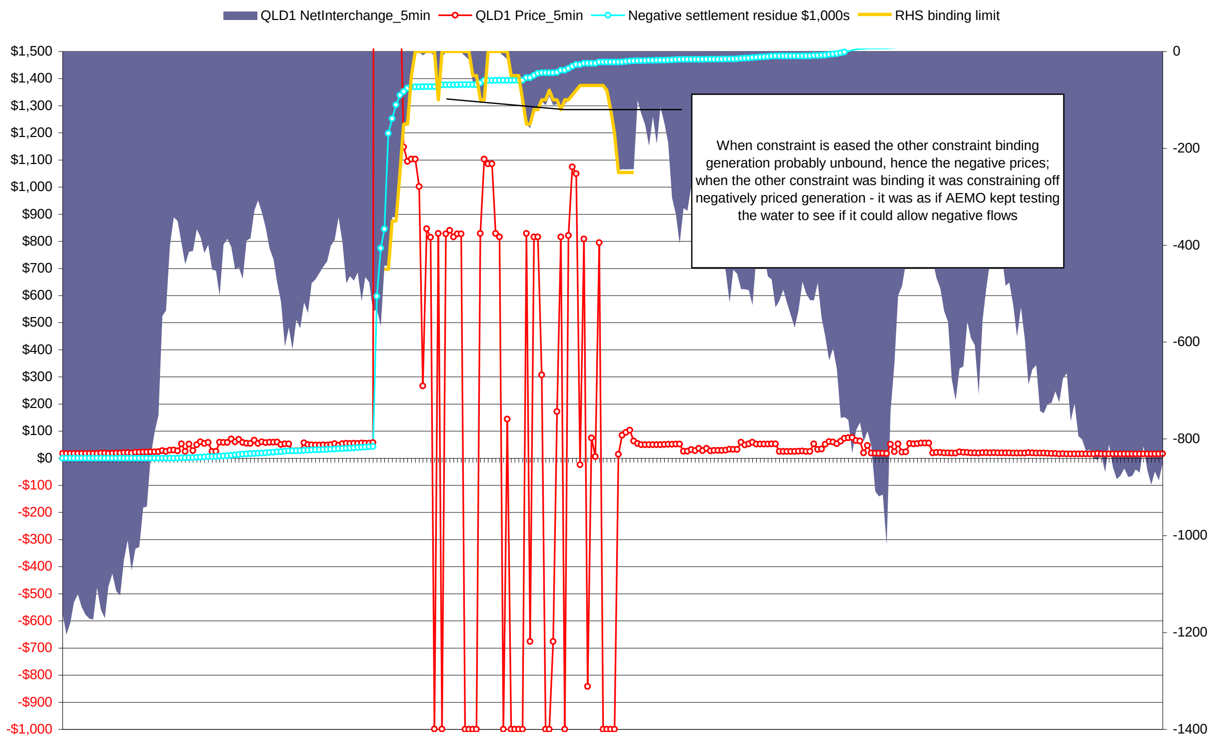


Figure 2 — 18th January 2011: flow, prices, limits and settlement residues



From DIs ending 1135 to 1605 the 5–minute price alternated between approximately $800/MWh and -$1000/MWh. For TI ending 1200 hrs on Tuesday, more than 9400MW of generation capacity in Queensland was offered at negative prices, up from approximately 6000MW for TI 1100. During DI ending 1300, negatively priced offers reached a maximum of 9857MW. High 5-minute prices were recorded in Queensland when the constraint equation was binding and constraining off negatively priced (-$1000 per MWh) generation offers.

The volatility associated with the January floods was not related to the rebidding of ramp rates. It is related to:

- the original formulation of equations (which can include nearly all generators on the LHS); *resulting in*
- catgeory c pricing with RRP being a function of numerous offer prices , rather than a single offer; *and then*
- the introduction of, and variability in, the negative settlement residue constraint equations.

The negative settlement residues change the intersection of the supply curve by 100's of MWs. This is usually after the exporting region's supply curve has been "flattened" with significant rebidding of constrained generators. This means the introduction of the negative settlement constraint often intersects the supply curve at very low prices. This usually means that the marginal MW can be provided and RRP can be set by an increment "up" of negatively priced generation that has been constrained off, first by the intraregional constraint and then by the AEMO negative residue constraint. This is through category B pricing – the constraint (not including the negative settlement residue constraint) effects dispatch but no longer effects prices.

In the first instance the constraint can result in category C prices creating a price that is a function of constraint coefficients and offer prices at the floor or the cap. The floor price can result in a high price if constrained off in setting the price under category C. In the example the constraint equation required participants to rebid to the price floor (as all had positive coefficients). The negative settlement residue constraint then reduced the overall dispatch of units priced at the floor and the intersection of supply and demand is now in the volume priced at the floor. A reason for the volatile prices in the period was AEMO's response to prices and the implementation of negative settlement residue constraints.

Due to the asymmetry between the price cap and floor 13.1:1, participants tend to "go long" which means they increase supply to cover their derivatives exposure. Participants using generation to cover retail load do the same. This increases supply.

The rebidding of ramp rates during this period may have changed the dispatch of generators (in the order they were constrained off), especially after the introduction of the negative residue constraint equation, which progressively constrained off 100's of MWs of generation. The rebidding of ramp rates did not, in the first instance create the price effects, as the interconnector was affected by other participants' prices, not ramp rates. If there were higher ramp rates offered by participants it is unlikely that there would have been significantly different outcomes, all that would have happened is upon the introduction of the NRM constraint the reduction of dispatch would have been concentrated on the participant (of those with -$1,000/MWh offers) with the highest constraint coefficient.

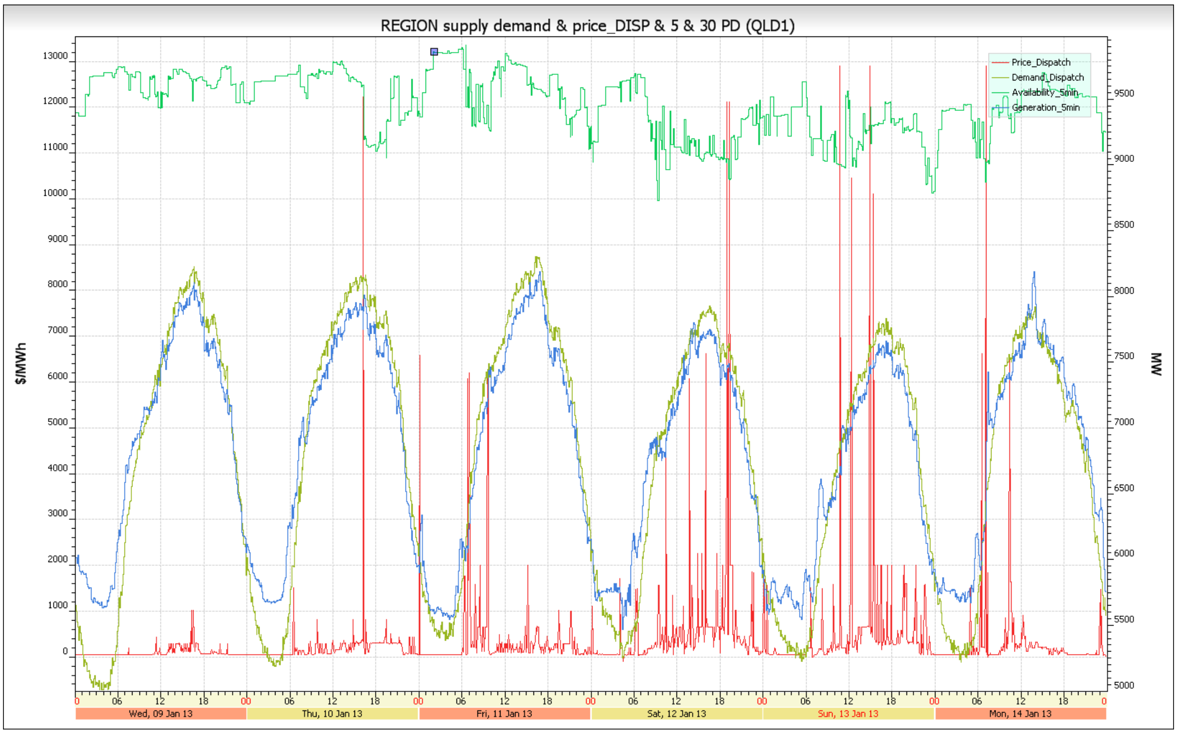
The very fact that ramp rates affect dispatch ***after*** rebidding offers to -$1,000/MWh shows the AER's Rule change proposal would not have changed the price effects significantly during the period.

January 2013

We have previously discussed the competitive dynamic at play during Q1 2013. Although the period was still within the school holidays, demand continued to increase throughout the working week and into the weekend. Demand peaked at only 8304MW in the 5 minute dispatch interval of 14:20 of the 11th. This is well below maximum demand for QLD and lower than demands in December 2012. Demand was also depressed by the highest temperature days being on the weekend.

Prices were volatile during the period, but noticeably did not feature significant periods of negative prices even though there were extensive periods of constraints binding dispatch.

Figure 3 **Supply, Demand, prices in QLD 9-14th January 2013**



Source: NEO 4.4 (IES), MMS Data tables

To analyse this period, a sample of 50 prices was taken from the period 9th-14th. The prices selected were considered occasions where the price could have been constrained. The aim of this analysis is to highlight the second most important factor in creating price volatility during constrained conditions which is when generators are unable to offer prices below the local price (and are constrained off) and start to set price with other constrained offers.

The results are shown in the chart below, where the RRPs are shown in ascending order with the thin blue line. This chart does not show the incidence of these prices during the period as the sample heavily weighted to the more interesting, higher prices affected by non-SRMC or sub -$300/MWh cap price bid bands.

Category A or B: (unconstrained pricing)

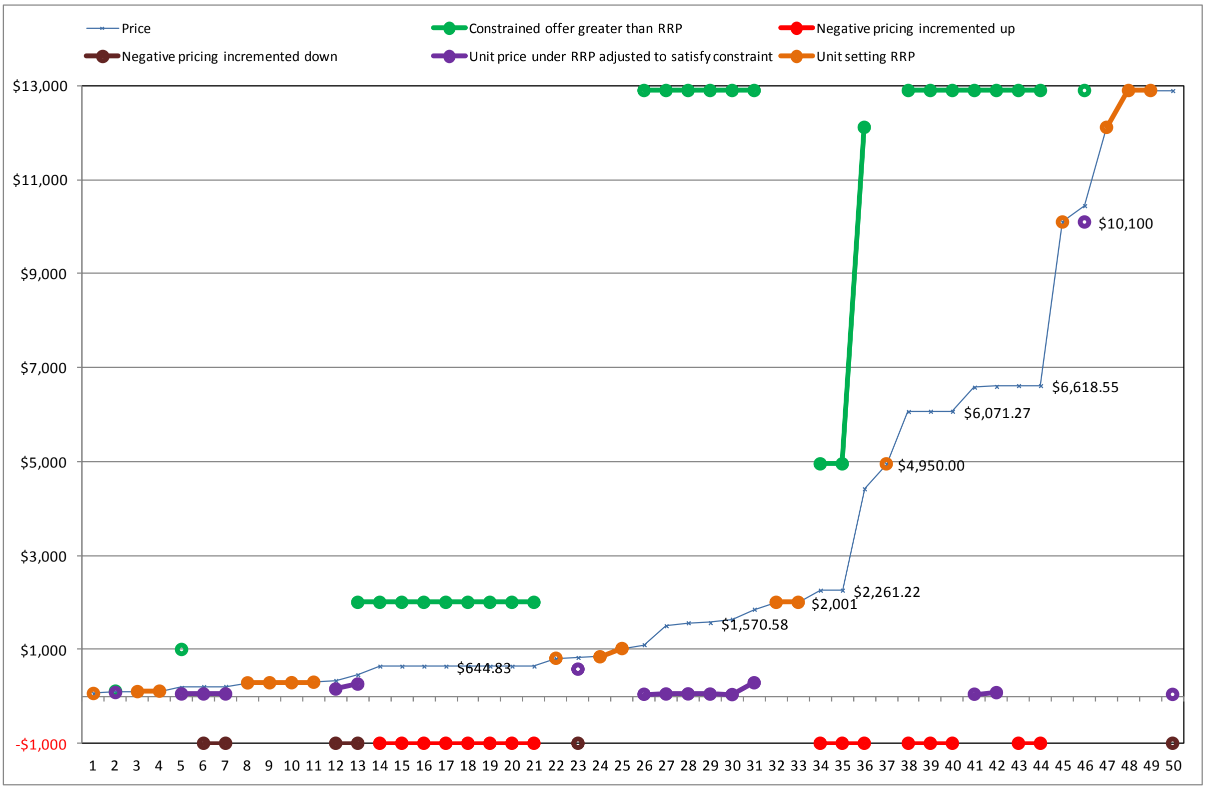
- Where a unit (or collection of units at same price) are setting the RRP this is shown in orange.

Category C: (constrained pricing)

- Where a constrained offer is greater than the RRP it is shown in green
- Where a constrained offer of -$1,000/MWh and incremented up it is shown in red
- Where a constrained offer of -$1,000/MWh and incremented down it is shown in brown
- Where a constrained offer is less than the RRP incremented up is shown in purple

These can be in combination, as is shown in the figure below.

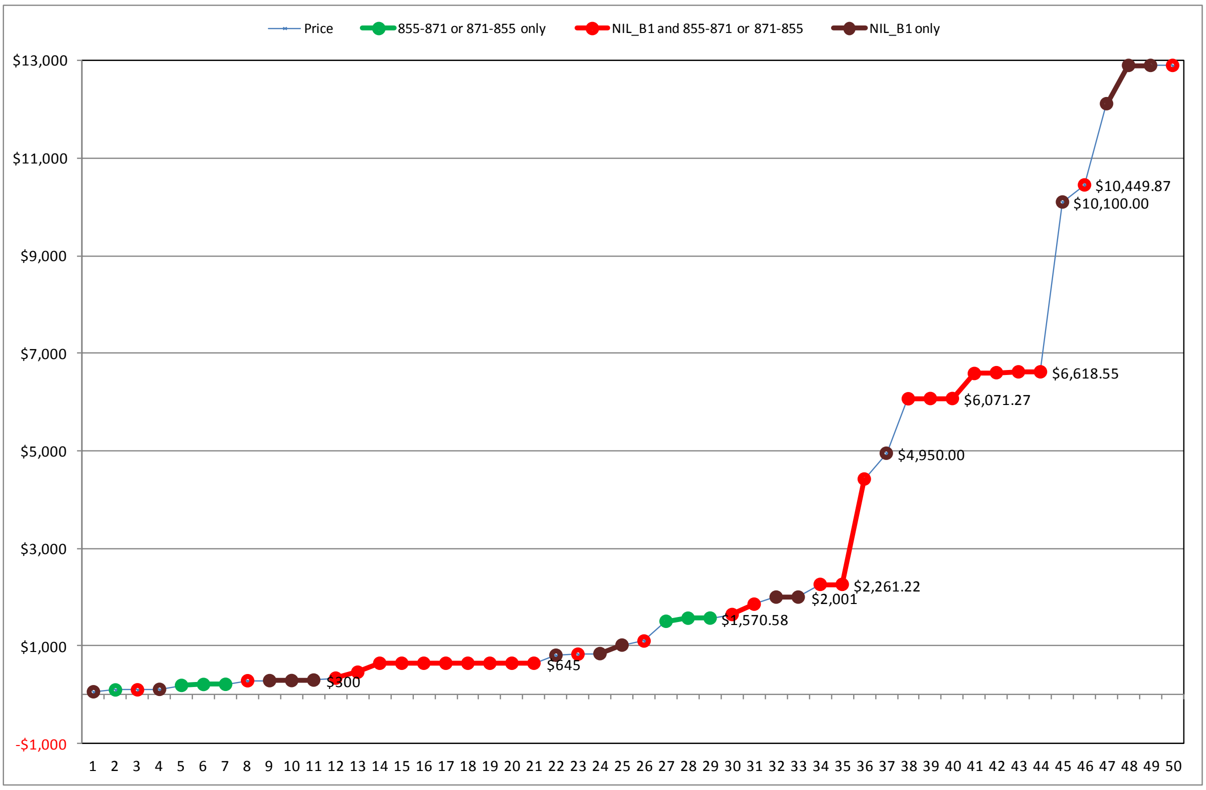
Figure 4 **Selection of 50 prices showing how the price was set in each instance**



It is evident from the first figure, which shows how prices were calculated from the sample of 50 over the period, that prices under constrained conditions can vary significantly depending on the volume offered in higher or lower price bands. The RRP under category C, when the marginal MW is simultaneously resolved with constraint equations, can be a function of increments of cost from constrained offers, either at the floor or cap. Of the selection, the only periods where the price was not affected by category C pricing is the orange "unit setting RRP" prices; category B pricing in those instances.

The following figure shows which constraint effected price from the sample of 50 over the period.

Figure 5 **Selection of 50 prices showing which combination of constraints affected price**



Because of the intra-regional constraint between Calvale-Wurdong/Stanwell, generators close to the sending end rebid to -$1,000/MWh to maintain dispatch volume, however, due to the relatively high prices, $150/MWh being offered (due to the conditions, supply and demand) participants further from the sending end needed not to rebid to -$1,000/MWh to be constrained and in turn the interconnector was not constrained by the equation in most instances. Instead, the interconnector limit was set by the voltage stability limit on the QLD-NSW interconnector (QNI) N^^NIL_B1, which constrains off Kogan Creek power station or reduces exports from the QNI and the smaller Directlink interconnector.

Generators on the receiving end of the Calvale-Wurdong/Stanwell constraint, in order to manage dispatch volume and not unnecessarily suppress prices, rebid capacity to the price cap or intermediate offer bands. A particular offer band that set price was at $2001/MWh. The category C prices resulting approximated at $650/MWh, as the $2001/MWh offer set the RRP in conjunction with negatively priced offers being incremented up. When the $2001/MWh volume fully cleared (up to 300MW) offers priced at $12,900/MWh set the price with negative offers and prices hovered at $6,000/MWh, well below the price cap.

The price at this point in time was the function of change in dispatch of units at the sending end and receiving end of the constraint, as the interconnector was effectively prevented from being dispatched, not by the Calvale-Wurdong/Stanwell constraint and rebidding of ramp rates but by the N^^NIL_B1 interregional constraint effecting the interconnectors.

The price volatility under category C was the result of the price being set by "disorderly" rebids. This volatility served to ***depress*** prices over the period. This is because the likely outcome without the Calvale-Wurdong/Stanwell constraint would have been $2,001/MWh or $12,900/MWh prices. The fundamental factor was that baseload generators must have had low derivatives sales for Q1 2013 and were exposed to the pool price – they had incentive to increase prices after the N^^NIL_B1 interregional constraint bound. Ergo, the generator-retailer participants must have also under contracted, were exposed to the pool price and had incentive to decrease prices. There was probably exposure to off-peak and shoulder periods (it was extremely humid with high overnight temperatures) as the generator-retailers could not operate their plants all day every day. The risks, caused by virulent competition in Q1 2013 were high and with hot weather prices reflected this. The Calvale-Wurdong/Stanwell constraint served to muddy the waters and effect dispatch and pricing.

The rebidding of ramp rates during this period did not prevent them being constrained off – as evidenced by the negatively priced offers setting the RRP. Participants close to the sending end of the constraint were constrained off and the very fact that generators on the sending end of the constraint, but further away did not rebid to -$1,000/MWh indicates that the ramp rate was unimportant. This is because the ramp rate did not force the other participants to rebid prices to the floor to be dispatched (they were not constrained off). We conclude the ramp rate rebidding was unimportant in price effects during the period. The period should not be used as evidence to necessitate this Rule change.

Question 5

(a) To what extent has the rebidding of ramp rates under constraint conditions led to inefficient price signals? Is there evidence to suggest this has led to investor uncertainty?

The AER alleges that generator rebidding under constraint conditions can reduce the effectiveness of peaking capacity and demand side participation as a physical hedge against high wholesale prices. Again, ramp rates are assumed to **prolong** the effects.

The NGF has a long standing position that demand side bidding should be as transparent as the supply side bidding. To suggest that the supply side bidding (which is fully transparent) somehow inhibits demand side bidding is counter intuitive, considering suppliers have to make offers under the restrictions of the Rules. The Rules require producers to offer prices in good faith, to make offers that reflect technical capability, to provide accurate representations of available capacity this is so the market is fair, transparent and so the system can be kept reliable and secure.

With regards to peaking generators the participants owning these assets have been using them instead of buying $300/MWh cap derivatives or other risk management products. These peaking assets may provide an imperfect hedge to their retail load as evidenced in Q1 2013. These assets have been used to reduce prices, therefore we can see no argument why it is bad that a generator used to reduce prices may be generating at low or negative prices – the reason why the price is low or negative ***IS*** because they are dispatched by their participant owners with low or negative offer prices.

If we consider the argument of the AER, it explicitly states that the rebidding of capacity to higher price bands is the primary reason, not ramp rates which only prolong the effect of rebidding capacity. It is inconsistent to on one hand to state that peaking capacity is unduly affected by the rebidding of ramp rates and then state the main effect of rebidding ramp rates is to "prolonging" the price effect. The very fact that these pricing conditions are prolonged by ramp rates (which we do not agree with in most instances) gives peaking generators the opportunity to participate, a second bite of the cherry so to speak.

Because of this second bite of the cherry, we see low or negatively priced periods after a high priced period. This is due to 5 minute dispatch and 30minute settlement in the NEM, where peaking generators can rapidly increase dispatch and receive the trading interval price. Thus we have high price followed by negative prices and the average price is lower because peaking generators have increased supply, but it is still profitable for the generators to run.

This brings us to consider the example given by the AER and cited in Figure 5.3 of the Consultation paper. It shows 5 minute prices in QLD on the 25th August 2012. The example is used to highlight the problems of generators rebidding during constraint conditions and provides AER's justification for the ramp rate rule change.

The 25th of August was a Saturday. Demand was low. The economic dispatch of generators as dictated by the market and reflected in generator offers resulted in constraint binding between Calvale –Wurdong/Stanwell. AEMO had recently implemented a new, automated method of invoking Negative Residue management (NRM)[7].

The constraint required generators on the sending end to be constrained off and those on the receiving end to be constrained off. These generators rebid capacity to avoid being exposed to higher costs of generation yet receiving the same price (this is why the constraint is binding, as it is limiting cheaper generators being dispatched).

Normally Calvale-Wurdong/Stanwell constraint only caused category B pricing outcomes because N-Q-MNSP-1 is unconstrained and can deliver the "marginal MW" from NSW to QLD. However under some rebidding,

[7] http://www.aemo.com.au/Electricity/~/media/Files/Other/Dispatch/Brief_on_Automation_of_Negative_Residue_Management.ashx

changes in circuit rating and changes in demand, category C prices can occur whereby the units constrained must be adjusted to set the price. This resulted in some temporary higher prices under category C, which were not sustained because they depended on N-Q-MNSP-1 being constrained[8]. In addition AEMO's automated NRM constraint was invoked and reduced the dispatch of QLD generators. These NRM constraints, coupled with significant rebidding to the price floor, resulted in very low prices.

The following chart shows the weekend dispatch and pricing outcomes. On the LHS axis the QLD demand is in grey and added to it is the flow on the interconnectors which are colour coded as to whether the price at the time included offer prices from participants constrained by the Calvale-Wurdong/Stanwell constraints[9] and/or the NRM constraint.

In the blue periods the export limit (which required imports to NSW) was set by the Calvale-Wurdong and Calvale-Stanwell constraints and the N-Q-MNSP-1 was also constrained so the price in QLD was affected by one of the Calvale-Wurdong/Stanwell constraints, requiring the Category C pricing.

The yellow periods are when AEMO implemented its NRM constraint equation to limit imports NRM_QLD1_NSW1 -Negative Residue Management constraint for QLD to NSW flow and one of the Calvale-Wurdong/Stanwell constraints were also binding. This meant we had both the constraints affecting prices (unless Wivenhoe or Swanbank were able to set price) and Category C prices prevailed.

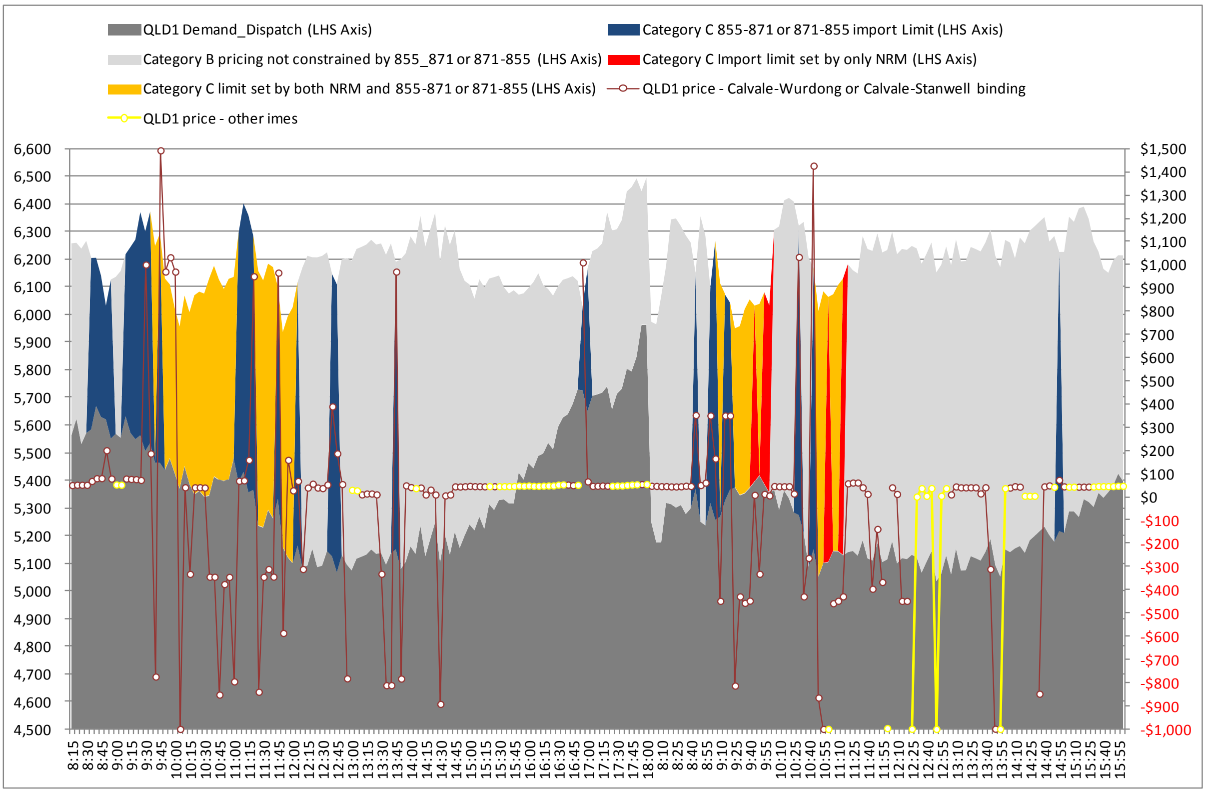
The red periods are when either of the Calvale-Wurdong/Stanwell constraints were not influencing the price calculaiton and NRM_QLD1_NSW1 is limiting imports to NSW.

In the grey periods, neither the NRM_QLD1_NSW1 or Calvale-Wurdong/Stanwell constraints are affecting pricing, even though one of the Calvale-Wurdong/Stanwell constraints may have been binding. For instance import constraints such as Q:N_NIL_BCK2L-G[10], which allow flows closer to the full rating of the interconnector may have prevented additional flow and resulted in QLD prices being low.

What is interesting about the period in question is that we had a significant period of volatility when one of the Calvale-Wurdong/Stanwell constraints was not included in the calculation of the QLD price (category B pricing).

The figure shows this dynamic over the period in question.

Figure 6 25-26th August 2012, pricing categories and the effect of constraints



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8 Over the weekend N-Q-MNSP-1 was constrained by N_X_MBTE2_A, Out= two Directlink cables, NSW to Qld limit to about 30-40MW

9 In the chart referred to as 855-871 and 871-855 constraints, in reference to the circuit numbers

10 Outage=Nil, limit Qld to NSW on QNI to avoid transient instability on 2L-G fault between Armidale and Bulli Creek

What is interesting is that there were:

- many occasions (grey) where prices were **not** set by simultaneously resolving 855-871 and 871-855 under category C pricing – typically priced at NSW or lower;
- few occasions (blue) when we had high prices from including offers from 855-871 and 871-855 under category C pricing – typically higher priced periods;
- more occasions (orange) when the price offers from 855-871 and 871-855 AND import limit set by NRM equation under category C pricing –typically lower price periods; and
- occasions (when price was set by the import limit set by NRM equation in isolation – typically lower price periods.

It is noticeable that the AEMO NRM constraint process can also create **positive** settlement residues (noting the NRM constraints often set the price negatively[11]). Please note this is contrary to the conclusions drawn in the consultation paper on page 24 where the AEMC states "*therefore limiting counter price flows through "clamping" would not change the returns to holders of SRA units*". If we look at the 25th and 26th the introduction of NRM equations clearly changes residues in favour of unit holders – it may have reduced flow, but created negative prices and this would have increased returns to unit holders. The NGF notes the AER analysis of the negative settlement residues only includes the negative settlements, not the positive residues accruing from AEMO's introduction of negative settlement residues.

However there were many occasions, especially on the Sunday when there was no effect of NRM, or 855-871 or 871-855 in combination or isolation, yet the price still dropped to -$1,000/MWh. This was during high flow conditions when another interconnector constraint bound.

This means there was just too much generation and a drop in the price, just based on underlying demand and supply NOT the 855-871 and NRM constraints, especially on the 26th. The average price during the period was -$33/MWh because of the run of low prices on the 26th in particular.

This leads us to question the impact of ramp rates on the 25th and 26th. The AER is correct in stating that generators with the highest constraint coefficient (closest to the sending end of the constraint) rebid their prices negatively and ramp rates down to 3MW/min to maintain their dispatch volume. They are correct that this can result in other generators rebidding prices negatively and ramp rates to 3MW/min.

Adopting the AER's Rule change, the generator closest to the sending end of the constraint (constrained off) would be constrained off at a higher rate, with those further from the constraint at a lower rate, than the present dispatch…only if the following conditions are met:

- interconnector has been constrained by another equation (such as its limit); and
- the generator can price lower than its local price.

If the generator closest to the sending end has a high ramping capability it may be constrained off rapidly if the constraint does not include interconnectors. Only in this instance this Rule change will concentrate the change in dispatch on the generator with the highest coefficient (closest to the sending end) instead of others. The AER rule change therefore concentrates congestion risk onto the generator under some instances, with these typically being category B pricing (which by definition cannot affect settlement residues).

The AER has complained that ramp rates can be "manipulated[12]", the Productivity Commission has called rebidding under constrained conditions as "strategic behaviour[13]" as has the AER[14] by generators who can "manufacture[15]" constraints. The AER stated that CS Energy with generators at the receiving and sending end of a constraint can "contribute to cause a constraint to bind".

The NEM design explicitly aims to prevent the manipulation of prices through regional rather than local, prices such that the cost of the constraint is not fully reflected in pool prices. As we have previously stated it is only under instances whereby a regional constraint results in the interconnector binding, or binds at the same time as an interconnector constraint, that the "cost" of the constraint may be reflected in pool prices (under category C

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[11] The NGF has previously commented the NRM constraint process is suboptimal as AEMO haphazardly changes the intersection of the supply curve by inputting the NRM constraint at the same time as offered volumes are received from generators – when doing this AEMO is clueless as to what the price is going to be and tends to err on the side of forcing the price in the exporting region low

[12] AER Rule change proposal, page 19

[13] Productivity Commission Electricity Network Regulatory Frameworks, Inquiry report Page 681

[14] AER Submission: possible options for interim solutions to congestion-related disorderly bidding, page 2

[15] AER Rule change proposal, page 19

pricing) and volatile prices can accrue. This is often because AEMO includes numerous generators on the receiving end of the constraint. That these costs make their way, in the few instances they occur, into prices may be important, as otherwise there is no way for the market to compensate participants for the lost revenue from being constrained and provide TNSPs and generators the incentives to resolve constraints.

If these price signals did not occur, such as if the generators at each end were constrained on and off with no change in RRP, producers would be supplying at a price they are not willing to receive and not supplying at a price they are willing to receive. From the NGF's perspective this would result in producers "subsidising" the cost of the constraint, though increased operational costs. This is the very intent of the AER's procrastinations[16] over generator rebidding under constrained conditions: the intent is to force producers to "subsidise" the operating cost of a transmission constraint. This is very poor policy because to force the wrong party to pay for the costs of another (in this case the transmission monopoly) will not incentivise the party causing the cost to avoid them.

The NGF believes this Rule change may be inefficient because:

- It may discourage generators from entering into forward hedge agreements as they are exposed to greater volume risk (especially those close to the sending end of a constraint that does not include an interconnector, or where there are other terms in the equation with markedly lower coefficients than they);
- The generator has no way of managing the cause of congestion. An outage of a transmission element is something controlled by the TNSP and AEMO, not the participant,

The NGF is surprised by the AER's complete lack of empathy with generators. We know the AER is a regulator and must act on the behalf of consumers, but this does not mean it should completely discount the interests of producers. It needs to strike a fair bargain between competing interests that satisfies the NEO. If the network business plans outages or does not augment the network adequately, generators have to pay the price in the NEM Rules as it is they who face not being dispatched. The AER appears to think that generators close to a constraint should not rebid and face losing considerable gross margin as their most economic dispatch is disrupted and their operating costs increased and not reflected in pool prices.

If we consider the example of the Calvale-Wurdong/Stanwell constraints, it appears the AER expected CS Energy to allow a change in dispatch of Gladstone and Callide generators, at a significant loss of profits, to occur without rebidding. This position is completely unreasonable.

We have previously mentioned that the effect of the AER rule change is to concentrate congestion risk onto the generator closest to the sending end of the constraint with the highest ramp rate. This is only the case when the constraint does not affect interconnectors and therefore prices (category B pricing). As opposed to the AER's analysis the Rule Change proposal will not significantly change the price effects it has highlighted as the reason for raising the Rule change.

The proposal is not ideal compared to the status quo, whereby generators can "share" the dispatch risk between generators included in the constraint equation. This dissipation of the constrained MWs helps manage the dispatch risk associated with the constraint and therefore "distributes " the costs imposed by the TNSP on generators by scheduling the outage (we shall cover this later).

(b) Have participants with peaking generators experienced higher levels of price unpredictability arising from the issues discussed above? Can these impacts be quantified?

We have covered this question adequately. No.

Question 6

(a) To what extent can a reduction in the effectiveness of SRA units be attributed to the rebidding of ramp rates under constraint conditions compared to other forms of generator rebidding?

The "effectiveness" of SRA units depends on the reason for purchasing the units, however taking the AER definition of a participant hedging a short position in one region against a long position in another, the NGF consider that SRA unit effectiveness is highly volatile and more likely to be affected by transmission outages than generator rebidding.

[16] The AER's discussions on rebidding, the ideas of reformulating constraints, changing ramp rates, CVPs

For the Q409 (Mt Piper to Wallerawang constraint) and Q113 (Gladstone area constraints) periods highlighted by the AER SRA units paid out 40-48% of the cap difference between the relevant states.

By comparison the Q111 period which was affected by flooding related transmission outages saw SRA units return under 1% of the cap differential between NSW and QLD. It is notable that the Q111 and Q113 results for QLD and NSW caps are startlingly similar with zero payouts each year in NSW and above $20/MWh in QLD.

Similarly during separate incidents of volatility during Q108 NSW-QLD SRA units reflected only 25% of the cap differential while the VIC-SA SRA units reflected 43%of the differential between the regions.

While specific pricing methodologies of products is not discussed by the NGF, we believe that this submission makes it clear that members would generally consider ramp rate rebidding is of low order consequence compared to other inputs.

(b) As a NEM participant, do you consider SRA units to be an effective instrument for the management of inter-regional price risk and have you used SRA units for these purposes in the past? To what extent has this changed due to the issues discussed above?

Yes, participants do use SRAs to hedge positions in adjacent regions. However they also take opposing positions in each region with derivatives transactions to also be exposed to the difference in prices without and risk to volume. In futures markets these are called "spreads" and sometimes firtm their own derivatives products depending on demand. Hedging with SRAs can be done by selling a swap in the other region and buying an SRA unit (or vice versa). In addition, SRAs may also be used to hedge positions in the region the producer has generation assets. If the generator has a potential exposure to high prices in its region, through outage risk (plant tripping, dispatch volumes lower than swaps, unfunded difference payments) it may acquire units that pay out upon higher prices in the region. Any participant trading units will need to be cognisant that they are not firm, in a similar manner that there is no guarantee the generator a participant owns will be available at time of high prices.

The NGF doubts the proposed Rule would increase the auction value of SRA units and would therefore not reduce network charges as indicated by the AER.

The AER appear to have interpreted the falling auction revenues as being related solely to actual payouts being below auction proceeds in recent years. The valuation of SRA units at auction will reflect the buyers' expectation about the future spot outturn of those units. Accordingly where there is an expectation of low volatility in the forward curve there is likely to be a decrease in the SRA prices.

Question 7

Would the application of the AER's proposed rule affect the valuation of SRA units and the impact on network charges?

We have previously commented that ramp rates are a low order of consequence when the constraints include interconnectors (and may create situations of category c prices). They are more important and therefore more valuable when constraints do not include interconnectors, do not affect residues (under category B prices). Under these instances rebidding of ramp rates allows the constrained volumes to be shared between participants on the sending end of a constraint.

Given we think ramp rates are not that important during times of category C prices when residues are affected we think the effect will be small. The Rule change proposal would have made little difference to the residues across the NSW-QLD1 in Q1 2013 for instance.

Question 8

(a) Is it valid to assume that generators would generally be able to operate at their maximum ramp rates submitted in accordance with schedule 3.1 of the NER?

The maximum ramp rates submitted with schedule 3.1 of the Rules are the maximum operating performance when registered with AEMO. It is not valid to think that these ramp rates can be achieved under continuous operation. To use a simple analogy would you drive your car at its maximum acceleration and braking performance all the time? You wouldn't because you know it will shorten the life of components and increase the risk of failure.

The AEMC also needs to be aware that altering the ramp rate capability to a technical capability basis will almost certainly lead to a greater frequency of unit trips due to flame instability in the boiler. This could under high demand scenarios, where intra-regional constraints are more likely to bind, lead to a desire from the AER to see units ramp faster, but then trip and result in loss of reliability to end users. A higher frequency of unit trips caused by a rule that required a higher ramp rate from the large coal fired would have serious negative financial implications on many generators struggling to survive in the NEM. At the moment participants internalise these cost tradeoffs through offering commercial ramp rates – these trade off cannot be made under the proposed Rule.

The AEMC needs to allow for large thermal coal fired generators originally being intended to operate as baseload plant with other fast start and high ramping capability plant also installed in the system to meet peak and other demand fluctuations. The baseload fleet in general is now some 30 years old and degradation of the original design tolerances and operating characteristic of the plant has altered considerable over this period.

Most of the black coal fleet was also designed to operated with coal of 24-26 GJ/Tonne and 22-24% ash coal, currently plant is operating with coal as low as 18 GJ/Tonne and 34% ash content, this would have a considerable impact on these generators operating with ramp rates exceed 3-5 MW/min.

(b) To what extent are the cost differences associated with different levels of ramp rates material and should this be taken into account in the determination of maximum technical ramp rates?

The NEM is a competitive market where cost information should not be disseminated between participants and in public forums (such as this consultation). The AEMC and AER should remember the demand for ramping and subsequent competition in the market to provide it will drive the cost of ramping/unit flexibility to efficient levels. This will be reflected in prices.

(c) Are there any issues relating to the ability of generators to determine the maximum ramp rates of their generating units?

For a large thermal generator the ramping capability can be described as function of the loading of the unit throughout its power range. For example a unit near minimum load will often have lower ramping capability than that higher in the power range.

The NEM Dispatch Engine (NEMDE) only allows generators to submit a single ramp rate per 30 minute trading interval. NEMDE does not allow generator participants to submit ramp rates as a function of loading of the unit, therefore the ramp rate submitted may not always reflect the capability of the unit as it is dispatched by NEMDE. The practical implication of the Rule Change Request is that generators would constantly need to revise their ramp rates offered to AEMO as the dispatch of the unit varies. For units at the margin, setting the price, this may require multiple re-offers of ramp rates through a trading interval as the cleared volume offered by the generator changes each dispatch interval. It may also require generators to constantly check pre-dispatch and re-offer ramp rates to AEMO for the Predispatch schedule, noting these values will change per trading interval predispatch schedule and be updated regularly as AEMO issues new schedules to the market.

Rather than place this onerous obligation on generator participants, AEMO should modify NEMDE so that generators can describe ramp rates offered to NEMDE as a function of offered volumes cleared (dispatched) by NEMDE. In so doing the compliance obligation will be simplified.

d) Are there any issues relating to enforcement of the AER's proposed rule?

The effect of this proposed rule is to expropriate ramping capability (at all times) by defining it as a technical service rather than a commercial parameter. This is simply the regulator subverting the market for a service on behalf of consumers, against producers. The regulator believes it will have significant price effects that mean it justifies the NEO (even though these are wealth transfers); although we have shown that ramp rates are a low order of consequence on price effects.

As we have previously stated the regulator needs to strike a fair balance between consumers and producers not just to act in the short term interest of consumers. In the short term the AER probably thinks this rule change could have reduced prices, on a few occasions that have mistakenly fuelled its ire, such as QLD during Q1 2013.

However in the long term producers will understand the regulator seeks to impose the costs of constraints (transmission) on participants, especially those with the highest ramping capability. Producers will be wary of such precedent and reconsider investments and operational practices especially if they are exposed to constraints.

Also in the long term, if regulator devalues ramping capability the market will not provide it. This will not be in the consumers' interest.

With regards to enforcement, the NEM has a strong compliance culture. This is largely due to civil penalties that can apply to the person. By applying further penalties to persons involved in spot trading it will inhibit competitive behaviour. It is not in the interests of regulators to inhibit competitive behaviour – this is likely to lead to inefficient prices.

The NGF considers that the proposed rule change would place significant cost burden on market participants. In order to comply with the new rules, participants would likely require:

- Some participants may need to improve dynamic ramp rate modelling capability. Most plant already calculate this for use in their controls systems however this value may or may not be appropriate for the use in bidding (for example plant which can move from one stable load to another at faster ramp rates than it can load follow).
- Additional off peak spot desk resourcing – potentially requiring desks to be actively manned 24/7 as opposed to the current practice of having "on call" traders backed up by alarms.
- Possibly additional peak spot desk resourcing to allow for the additional data assimilation.
- Depending on the solution each participant pursued this would require either significant additional IT provision (alarms, raw data dissemination, record keeping etc), training for plant operators (increasing their workload) or both.
- Additional internal compliance checks are likely to be required, whether in real time or day+1.

Participants would be exposed to increased compliance risk, especially from minor oversights creating technical breaches. The AER have attempted to address this in their commitment to update the rebidding guidelines, however the NGF note that the process would remain subjective and be subject to change with less scrutiny than rule changes. It would also be unrealistic to expect participants to take a "close enough" approach given the penalties involved to compliance during quiet periods and the often unpredictable nature of the NEM.

The NGF are also concerned that the proposed rule change would lead to plant regularly having reduced ramp rates compared to the status quo. As acknowledged by the AER, many units provide AEMO with both bid ramp rates and SCADA output from their control systems, enabling AEMO to take the more restrictive of the two for use in NEMDE. We note participants are presently expected to rebid to follow SCADA data. As SCADA decreases this provides no change to NEMDE as SCADA would be used rather than the higher bid value, however when the SCADA value increases the bid value is likely to lag despite the best efforts of the duty trader. There is a valid concern that the duty trader will be exposed to civil penalties under this instance. It provides a disincentive for participants to provide the SCADA data in the first instance, which in turn could lead to problems with dispatch and system security.

Question 9

Would a requirement to submit ramp rates that reflect the technical capability of generating plant increase risks to generators? What form would these risks take and can they be quantified?

Yes, we suppose there will be civil penalties associated with these Rules.

With regards to the AEMC's heading *"6.1.2 Are the use of ramp rates legitimate as a means of managing dispatch risk?"* we can only agree. If a transmission company arranges an outage that curtails the output of a generator the participant owning the generator cannot do anything to mitigate it, especially under category B prices. Under category C prices the cost of congestion may be reflected in prices, but this relies on all other generators and interconnectors being constrained (otherwise it is category B). For constraints not affecting prices (residues) under category B outcomes we have stated it will concentrate dispatch risk on those closest to the constraint. This will increase volume risk for these participants and force them to subsidise the cost of the constraint.

Please note we do not share the AEMC's confidence it the Optional Firm Access proposal (footnote 11 on page 28) which is supposed to generate "side payments" to keep the generator financially whole. The OFA explicitly distributes the residues across the constraint, not more, and is therefore limited by the constraint – this is a major weakness in the design of OFA – The NGF has previously stated that if you don't want generators to be exposed to the risk of the constraint then the access model needs to go into deficit.

"NGF members cannot see any difference between the firmness of the OFA models and Non Firm Access models. They are both non-firm. Under the current arrangements you receive access to the RRN for the quantity of generation in the *flowgate*, with the total quantity being the capability of the *flowgate*. This remains true for the optional firm access model where ∑E = ∑U = FGx. All the OFA model does is ration *flowgate* capacity between participants in a different manner than existing arrangements."

This is not the first time the AEMC has "over-sold" the benefits of OFA in its documents, if we remember correctly obsequious comments were made in the AEMC's review of negative settlement residues. The NGF does not yet share the AEMC's confidence in OFA.

Question 10
(a) Would the proposed rule create an incentive for generators to actively reduce the technical ramp rate capability of their generating plant?

If generators are behind a constraint that consistently results in category B prices, (does not include the interconnector and the RRP), it is likely that they will not wish to be consistently constrained off at their higher ramp rate before the next generator is constrained off. The NGF notes the full ramp rate of the generator with the highest coefficient would be fully utilised used even if the difference between the two generator's coefficients was a matter of only four decimal places. A difference of 0.0001 in the constraint coefficient would be enough for the linear programme to determine that one generator is constrained down below contracts at its full ramp rate (at a cost of (MW x (RRP – Strike)) / 2 for the Trading Interval and another not (if we assume both have rebid to -$1,000/MWh.

(b) Since the making of the AER's previous rule change request, have conditions in the NEM changed such that a minimum ramp rate of 3 MW/minute is no longer sufficient?

No.

(c) Would generators be able to negate the effects of wear and tear by bidding volumes within price bands as suggested by the AER?

If they are behind a constraint whereby they can price below interconnectors the wear and tear burden will be distributed. However if generators are behind a constraint that consistently results in category B prices, the generator closest to the sending end of the constraint will face the full burden (assuming all others rebid prices, as they should).

Question 11

(a) What are the costs and benefits of requiring generators to submit minimum ramp rates for each of their individual physical units rather than a single minimum ramp rate for the aggregated total?
(b) Does the view still hold that the aggregation provisions can be used to manage concerns around incentives to aggregate?

This Rule change proposal is about submitting the technical capability of ramp rates, not about the aggregation of units. If the AER wanted to change the ramp rates of aggregated units it should have raised a Rule change request doing so. If the "problem" the AER is trying to "fix" is the ramp rates of aggregated units and not other units then they have erred in raising this Rule change proposal.

These questions are out of scope. The NGF is annoyed that if the AER has a problem with one particular element of the Rules, pertinent to a few participants, it has decided to raise a Rule change that affects every participant. It also suggests the Rule change proposal is misguided.

Question 12

(a) What are the costs and benefits of requiring generators to submit maximum technical ramp rates only at times of network constraints?

No comment.

(b) Are there any variations to this approach, such as the use of average ramp rates, which may be more preferable?

No comment.

Question 13

(a) What are the costs and benefits of requiring generators to submit a ramp rate that reflects a percentage of the capacity of their generating plant?

In absolute terms being constrained off costs a participant the same amount, irrespective of the size of the generator. There is no rationale to suggest bigger generators should be constrained off more. Larger generating units are not necessarily the faster ramping units in any case.

(b) Assuming adoption of this approach, what percentage of capacity should be required?

No comment.

Question 14

Are there any other alternative approaches? To what extent could an alternative approach be based on incentives rather than relying on regulatory/technical requirements?

We have previously discussed in reference to this rule change that under category B pricing constraints this rule change will concentrate congestion risk on the generator closest to the sending end (once participants have rebid prices to the floor). This is not the intent of the Rule change, but is its effect.

Given this forces a single generator to subsidize the cost of the constraint to the TNSP, as highlighted in 6.1.2 of the consultation paper we would need another way to minimise this dispatch risk (the subsidy).

The NGF came up with a number of options with regards to improving the existing Rules in response to consultation to the 1st Interim Report of the Transmission Frameworks Review. All were ignored by the AEMC at the time, which instead of modifying the existing rules decided to compare option1 (the existing rules) with OFA.

A way to do this would be if the TNSP "sold" swaps to the constrained Participant at fair value at the constrained volume and therefore instead carried the financial risk of deviation against the RRP, rather than the generator. The TNSP would therefore be exposed to the market costs of the outage and the risk would be taken from the generator. The TNSP could then decide whether to reschedule the outage if these costs were too excessive.