ACIL ALLEN CONSULTING

PREPARED FOR
SNOWY HYDRO LIMITED

27 MARCH 2014

REVIEW OF ASPECTS OF AER'S RULE CHANGE PROPOSAL

GENERATOR RAMP RATES AND DISPATCH INFLEXIBILITY

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1 Introduction

1.1 Background

ACIL Allen Consulting (ACIL Allen) has been asked by Snowy Hydro to review key aspects of a proposed rule change[1] requested by the Australian Energy Regulator (AER). The proposed rule change seeks to impose a requirement on generators for ramp rates and dispatch inflexibility profiles to reflect technical capabilities. This review is focused largely on ramp rates. However a number of the issues identified are also applicable to dispatch inflexibility profiles.

The AER is proposing that generators be required to submit at all times ramp rates that reflect the maximum the generator is safely capable of achieving. Presently generators are required to submit a minimum ramp rate of 3MW per minute. Submitting ramp rates above this minimum is presently a matter for the generator.

In general the National Electricity Market's (NEM's) energy market provides incentives for the generator to submit ramp rates sufficiently high to allow it to be dispatched in accordance with its dispatch offers.

1.2 Context

The context of the AER's proposed rule change is "congestion-related disorderly bidding". This phenomenon arises essentially as a response by generators to shortcomings in the design of the NEM, namely:

- the regional market model under which generators receive a regional reference rather than nodal price and
- the absence of compensation payments to generators when generators are constrained off by intra-regional transmission constraints.

At times of congestion in the transmission system, generators are presently able to rebid ramp rates to limit the extent to which they might be constrained off. As the Australian Energy Market Operator (AEMO) is required to respect these ramp rates, it attaches to them relatively high "constraint violation penalties". In calculating dispatch it is required to relax other constraints ahead of these ramp rate constraints. AER contends that the resulting dispatch outcomes are not economically efficient and that they would be more efficient if generators were required to submit their maximum safe ramp rates at all times.

1.3 Statement of issues and alleged benefits

Issues stated by the AER in its proposal include

1. problems associated with disorderly bidding including dispatch of high priced generation (productive efficiency) and impacts on interconnector flows (inter-regional trade); and

[1] Request for Rule Change – Requirements for ramp rates and dispatch inflexibility profiles to reflect technical capabilities, 21 August 2013.

2. the distinction between commercial and technical parameters of a generation dispatch offer.

AER claims that its proposed rule change will be beneficial in terms of

1. improved security of supply of electricity;
2. price of supply of electricity;
3. efficient investment in transmission infrastructure; and
4. improved ability for inter-regional hedging and improvement in inter-regional competition.

1.4 Structure of review

Our comments on the issues stated and benefits alleged by the AER are structured in the following sections of this review document –

Generator dispatch offers – technical and commercial parameters in which we comment on the AER's distinction between technical and commercial parameters (Chapter 2);

System security and efficient dispatch in which we comment on AER's alleged security of supply benefits (Chapter 3);

Inefficient dispatch and "unnecessary" price volatility in which we comment on AER's claimed "price of supply of electricity" benefit and the productive efficiency issues raised by the AER (Chapter 4); and

Inter-regional trading in the NEM in which we assess the AER's claims relating to improved ability for inter-regional hedging (Chapter 5).

1.5 Conclusions

Noting that the Australian Energy Market Commission's (AEMC's) Transmission Frameworks Review (TFR) Final Report recommended the Optional Firm Access (OFA) Model as a longer term solution to managing congestion in the NEM, the AER states that "given the seriousness of the disorderly bidding problem, and the high costs for consumers, we consider an interim "partial fix" is required earlier"[2]. We suggest that the AER overstates the seriousness of the disorderly bidding problem and note that "high costs for consumers" have not been demonstrated.

The imposition on generators of a requirement to submit at all times ramp rates that "reflect the maximum the generator is safely capable of achieving" would be both burdensome to generators in general, and inequitable to those generators who will be effectively penalised for possessing superior technical capability in terms of rate of change when transmission is congested.

The AER claims that its rule change proposal "seeks to clarify the distinction between the technical and commercial parameters of the bids" [3] Clearly it is not valid for ramp rate to be regarded as a "technical" parameter. It is clear that to operate a functional power system, AEMO is required to source from market participants two technical capabilities – that of generating at a nominated capacity and that of varying this capacity at a nominated rate. To some extent this is recognised in the designs of the NEM's existing energy and ancillary service markets.

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[2] Request for Rule Change, 21 August 2013, p.2

[3] Ibid, p.3

These markets serve the NEM's current requirements but there is nothing "complete" about the design or number of markets implemented. For example the introduction of a market for inertia has been advocated to support further penetration of wind energy in some NEM regions. Previously the rate of change provided to AEMO through submitted ramp rates has been adequate for its purposes. While the requirement imposed on generators is in the form of a minimum, opportunities in the energy market provide, under normal conditions strong incentives for generators to make maximum ramp rates available. This consideration should make it clear that the ramp rate is in fact a commercial parameter.

Under the AER's proposed rule change, when transmission is constrained, a maximum ramp rate that is high relative to that of other generators has detrimental commercial consequences. The ramp rate should remain a matter for generators. If it is the case that at times AEMO lacks sufficient rate of change capacity, this should be addressed by introducing a market mechanism whereby generators are able to make offer prices for incremental ramping capacity. There is no doubt that higher rate of change is available at higher cost. As a matter of principle, the possession of superior technical capability should be rewarded not penalised. The distinction the AER makes between the commercial and the technical parameters of an offer is arbitrary and constitutes an inadequate basis for making the case that generators should be precluded from submitting ramp rate based on considerations (typically commercial) other than what is the current, safe maximum.

Disorderly bidding is a rational generator response to shortcomings in market design and the NEM's transmission frameworks. It is the shortcomings rather than the response that rule change proposals should seek to address. The problem is not disorderly bidding but the absence of compensation for being constrained off. As explained by the AEMC, when disorderly bidding is occurring, "because offer prices are identical, dispatch priority is based on secondary factors such as ramp rate limits, prior period output and constraint coefficients.[4] It is perverse that the effect of a rule change proposed as an "interim partial fix" is for a generator to be accorded lower dispatch priority (equivalently lower priority access to transmission) for the simple reason that it has superior technical capability in terms of rate of change. It is a basic principle of markets, that such superior technical capability will be made available when there is a reward or commercial incentive for it to be so.

In summary :

- Disorderly bidding is a rational response by generators to shortcomings in market design. Proposed rule changes should deal with the shortcomings not the response.
- Ramp rate or rate of change is as much required by AEMO to fulfil its market and system operator role as capacity. It should be sourced competitively through a market rather than through regulation.
- The present lack of an explicit payment for ramping capacity in the NEM is not determinative of the classification of ramp rate as a technical rather than commercial parameter.
- Productive efficiency losses associated with disorderly bidding are small and not all due to rebidding ramp rates.
- It is doubtful whether price volatility caused by disorderly bidding acts as a deterrent to investors in peaking plant and materially affects the pricing of hedges.

[4] Final Report – Transmission Frameworks Review (TFR), AEMC 11 April 2013, p.109

- It is doubtful whether the increasing prevalence of counter price flows materially affects inter regional trading as settlement residues have never been considered an effective interregional hedge.
- The proposed rule change is unfair as it will commercially disadvantage flexible plant. Superior technical capability should be rewarded not penalised.

2 Generator dispatch offers – technical and commercial parameters

2.1 Technical and commercial parameters

The AER asserts a distinction between the technical and commercial parameters of generators' dispatch offers (bids). According to this distinction the generation quantity a generator associates with an offer price for a dispatch interval is a commercial parameter (because it has an associated offer price) and the rate of change or ramp rate (up and down) the generator submits for the dispatch interval is a technical parameter (because it does not have an associated offer price). This distinction is simplistic. Both generation quantity and rate of change should be more properly considered as the primary technical capabilities AEMO needs to operate a functional power system.

As market and system operator for the NEM, AEMO is required to dynamically balance supply and demand. The process by which AEMO achieves this can be referred to as security constrained economic dispatch. Viewed statically, supply and demand is balanced by ensuring sufficient power generation capacity is available to be dispatched to meet demand. Viewed statically, within a particular time interval, demand is met economically (at least cost) by dispatching committed generators (i.e generators already operating in the previous time interval) to their available capacity in increasing order of short-run marginal (variable) cost. According to this static view, particular generators are distinguished only by their short-run marginal costs.

2.2 Generation quantity and rate of change

However, because demand fluctuates over time, and electricity cannot be stored, supply and demand must be balanced instantaneously. Additionally then, AEMO must ensure that in aggregate, the output of available generators is sufficient to follow demand over time. AEMO is concerned with available generation capacity (generation quantity) and rate of change.

Traditionally it is customary to speak of generators performing specialised roles or duties namely base-load, peaking, and load following. Base-load plant is characterised typically by relatively high capital cost, relatively low variable cost (largely fuel cost), and relatively high start-up costs. Peaking plant is characterised typically by relatively lower capital cost, relatively higher variable cost (or opportunity cost of energy in the case of energy constrained plant such as hydro-electric generators), and relatively lower start-up costs. Load following plant is any plant that has the flexibility to vary its output to match changes in demand. Typically then, base-load plant will run continuously, peaking plant will be generating at times of peak demand, and some sufficiently flexible plant will be responding to continuous variations in demand.

Hypothetically, if the energy market were operated in real time (generation being dispatched instantaneously), load following plant would simply be the plant that is marginal in terms of dispatch offer pricing. However the energy market is not operated in real time but on the basis of five minute dispatch intervals.

At the commencement of a dispatch interval AEMO forecasts demand and unscheduled generation and issues dispatch targets for scheduled generators on the basis of their dispatch offer prices. This implementation of the energy market leaves the problem of how to instantaneously match supply and demand given that

1. demand and unscheduled generation will vary within the dispatch interval,
2. the interval forecast of demand and unscheduled generation will be inaccurate to some extent, and
3. scheduled generators may not conform fully with their dispatch targets.

In the NEM, the traditional "load following" duty is performed both by generation in the energy market that is marginal in terms of its dispatch offer pricing, and generation that participates in the frequency control ancillary services market.

That the NEM design provides presently a formal offer structure around capacity (energy or generation quantity), and does not provide a similar structure for rate of change (outside of FCAS) should not be seen as determinative of capacity and rate-of-change as commercial and technical parameters respectively. Conceivably, had the NEM's generation systems at the NEM's commencement been lacking in sufficient aggregate capacity to ramp up and down in accordance with changing aggregate dispatch requirements, an explicit market for ramping might have been considered. Of course it is not surprising that the nation's pre-NEM generation systems were sufficiently endowed with adequate ramping capacity as historically new generating plant was added to each system not simply to meet peak demand and energy requirements but to perform the specialised duties needed in functional power systems.

Indeed in practice both technical capabilities – generation quantity and rate of change are provided to AEMO on the basis of commercial incentives. That the market rules do not provide presently for offer prices to be associated with increments of rate of change is not relevant in deciding whether rate of change is a technical or commercial parameter. Under normal market and system conditions (when congestion is absent), the energy market incentivises generators to submit ramp rates that allow them to be dispatched consistently with their dispatch offers. However when congestion is occurring or should there be other circumstances under which AEMO finds itself with insufficient aggregate rate of change there may be a case for the establishment of a new market in rate of change.

3 System security and efficient dispatch

The AER proposes that generators be required to submit ramp rates (at all times) that reflect the maximum the generator is safely capable of achieving. The AER cites system security benefits as AEMO will have the ability to move generators more quickly to alleviate constraints. However it is not clear that there is a system security issue. It appears then that AER is really referring to the cost of AEMO managing system security.

3.1 Cost of ramping

AER foresees its proposed rule change resulting in reduced costs of AEMO managing these issues. However this is on the basis of greater ramping capacity being available to AEMO at no cost. Providing AEMO with access to the generator's maximum ramping capacity at all times is tantamount to instituting an unpriced (free) ramping service. It is recognised that there is a "wear and tear" issue associated with the cycling of generating plant. As it is the asset owner that will ultimately bear the costs of increased risk of breakage and accelerated depreciation, it is appropriate that the asset owner or asset operator on the owner's behalf determine the available ramping capacity at any time.

Potentially AEMO's use of a maximum ramp rate during a dispatch interval may preclude the maximum ramp rate being available to the generator at another dispatch interval when it is required to meet its commercial objectives. It is appropriate then that generators retain control over the extent of ramping over any dispatch interval either by retaining the current arrangement of rebidding ramp rate to achieve commercial objectives or by providing an offer structure for ramp rate.

AER suggests that generators can manage the "wear and tear" issue by rebidding volumes within price bands to limit the frequency and amount of their output changes. While this is feasible, it complicates the dispatch offer formulation process, increases the frequency of rebidding and may not always be effective. It is better to give generators direct control over the management of their technical capability to ramp by either retaining the current arrangements or providing an offer structure for ramp rate.

As mentioned the context around the AER's proposed rule change is transmission congestion-related disorderly bidding. Typically under these conditions generators compete for access to available transmission capacity by reducing their dispatch offer prices. However as all generator dispatch offers must be above a minimum price, other things being equal, priority of access will depend on other factors including ramp rates. It is unfair that a generator should be penalised for its technical capability and have its flexibility used by AEMO to its commercial disadvantage. It is an essential market principle that market participants be incentivised to make more of their technical capability available when there are commercial rewards for them to do so.

3.2 Limitations of current minimum ramp rate

In its consultation paper the AEMC asks whether the current minimum ramp rate hinders AEMO's ability to determine an economically efficient dispatch arrangement while maintaining system security[5]?

Presently the Rules stipulate that generators must specify as part of their dispatch offers a ramp rate of at least 3MW / minute. In general, the energy market provides generators with an incentive to include a higher ramp rate as generators will want to be dispatched consistently with their dispatch offers.

The phrasing of the AEMC's question is to some extent problematic. It speaks of "AEMO's ability to determine an economically efficient dispatch arrangement while maintaining system security". The problem is that a dispatch arrangement can be decided to be economically efficient alternatively by

1. optimisation that minimises variable generation costs unconstrained by ramp-rates,
2. optimisation constrained by particular ramp rates (whether minimum, maximum, or those preferred for whatever reason by generators at the time), or
3. optimisation that jointly minimises variable generation costs and costs that might be associated with changing the generation level (rate of change or ramp rate).

While the current market design does not provide for an offer price structure to be associated with ramp rates, it does provide for ramp rates to be rebid and presumably in some cases these are rebid to reflect the cost to the generator of making ramping capacity available to AEMO.

Given that dispatch in the NEM is calculated as a security-constrained optimisation of energy and ancillary services markets, it is inappropriate to conclude that a particular dispatch arrangement is economically inefficient based on generator dispatch offers alone.

The conclusion that the AER's proposed rule change would improve the economic efficiency of dispatch, depends on the assumption that the dispatch optimisation is correctly formulated and there are no differences in the costs to generators in making incremental (or decremental) ramping capacity available to AEMO. In fact there are such cost differences (in the case of coal-fired plant for example ramp rate can be increased by co-firing or switching to a higher grade fuel). It is not clear that AER's proposed rule change would improve the economic efficiency of dispatch.

[5] Consultation Paper, National Electricity Amendment (Generator ramp rates and dispatch inflexibility in bidding) Rule 2014, AEMC 13 February 2014, Question 1, p.13.

4 Inefficient dispatch and "unnecessary" price volatility

4.1 Cost reflectivity of dispatch offer prices

The AER explains that disorderly bidding is bidding by generators in a non-cost reflective manner, typically in response to transmission congestion. It appears to be intended by the AER that cost reflective means reflective of ascertainable variable generation (typically fuel) costs. However generation dispatch offers in the NEM are not generally cost reflective in this sense. They are rather opportunity cost reflective, and can be interpreted as the prices at which the generator is indifferent about having the relevant dispatch quantities dispatched or not. In this sense they validly take into account system and market conditions including transmission constraints. That dispatch offer prices need to be opportunity costs follows from the energy only market design. If generators are to recover their fixed costs from the energy only market it is necessary that at times spot prices must be allowed to exceed a price level that might be associated with a variable generation cost. An alternative market design might provide a capacity payment to cover fixed costs and then stipulate that dispatch offers must correspond to ascertainable variable generation costs. But such is not the NEM.

4.2 "Unnecessary" price volatility

The AER refers to an increasing prevalence of "disorderly bidding [which] has led to inefficient dispatch and created unnecessary price volatility which is impossible to predict"[6] . Disorderly bidding is a rational response by generators to a particular shortcoming in market design, namely the possibility of being constrained off in the dispatch process by another generator due to insufficient transmission capacity without compensation. According to the AEMC, "in international terms, this is an unusual market design"[7] . The associated spot price outcomes are a manifestation of these shortcomings and the rational responses of generators. The unnecessary price volatility referred to by the AER is only "unnecessary" from the point of view of a market design other than the NEM. With respect to this volatility being "impossible to predict", in general all spot price volatility in the NEM, "necessary" or "unnecessary" is impossible to predict which is one reason why participants in the NEM maintain high hedge levels.

The AER claims that this "unnecessary price volatility" is resulting in higher hedge contract prices and higher retail tariffs. The extent to which these prices are higher is not quantified. Further it is asserted that "prices for hedge contracts are based on the market's expectation of spot prices adjusted by a risk premium". This is an overly simplistic and theoretical explanation of price formation in the wholesale electricity contract market. Given that the market always remains highly hedged, it would appear unlikely to be the case in general that at some expected future spot price relative to wholesale contract price, participants would elect to be fully exposed to the spot market.

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6 Request for Rule Change, p.1.

7 TFR, p.5.

It is problematic to maintain that hedge prices are based entirely or even largely on future spot price expectations. But accepting that one can compare a contract price with an average spot price and find that in general the contract price is higher than the average spot price and interpreting the difference as a "risk premium", it will be important to consider what the "risk premium" actually represents.

Is it historical volatility or is it more of an "uncertainty" premium? Arguably the market has not been sufficiently stable for it to be historical volatility. If it is uncertainty (in contrast to risk measured historically) that dominates, then some reduction in the level of average spot price and spot price volatility may not have a material impact on pricing in the wholesale electricity hedge market. AER's cited" price of supply of electricity" benefits would seem to be doubtful.

Electricity spot prices in the energy only market are potentially extremely volatile and this volatility is typically unpredictable however caused. Projected annual spot price volatility, typically measured as a cap value (calculated as the sum of the positive differences between spot prices and a specified strike price divided by the number of trading intervals over the relevant period) is the relevant signal for investment in new peaking generation. This generation is required to be flexible so as to capture very high prices that might appear suddenly and persist for relatively short intervals. It is doubtful that the occurrence of "unnecessary" price spikes associated with disorderly bidding will have an effect on these primary considerations. In a discussion of the impact of the AER's proposed rule change on intending investors in peaking generation it is relevant to point out that the possibility of being constrained-off without compensation as a result of having responsive plant and having to submit at all times the safe maximum ramp down capacity does seem to be a deterrent.

4.3 Productive efficiency losses

According to the AER "there is a clear productive efficiency loss from disorderly bidding through high-cost generation being dispatched in place of low-cost generation". It appears that what AER means by high-cost and low-cost generation is high variable cost and low variable cost generation as indicated by the dispatch offer prices the various generators use under typical market conditions (the absence of congestion). At times of congestion, generators adopt relatively low dispatch offer prices in an attempt to maximise access to available transmission capacity.

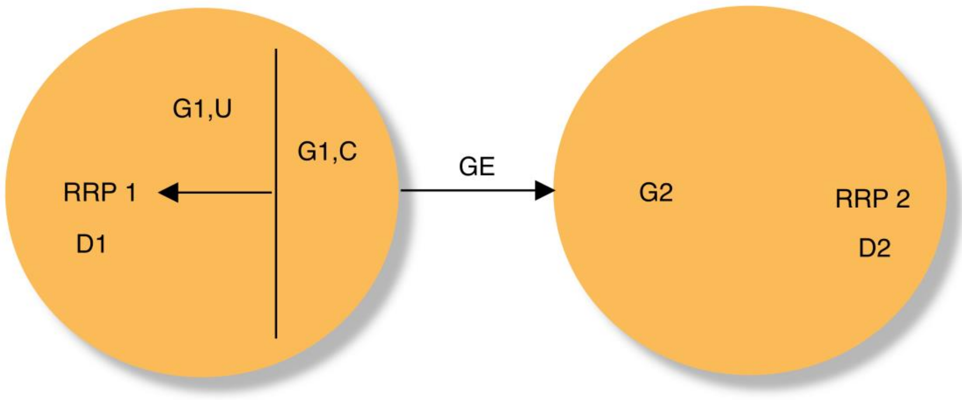
As explained, while these dispatch offer prices (which are not infrequently highly negative) do not reflect variable generation cost, they are validly reflective of market and system conditions. It does not follow that there is a "clear productive efficiency loss" associated with the resulting dispatch. "Disorderly bidding" occurs relatively infrequently, in many cases competing generators have similar variable generation costs (to the extent these are relevant), and the price at the regional reference node is typically considerably higher than any differences between these variable generation costs. Indeed while stating that things might be different in the future the AEMC states that "it is generally accepted that the direct costs of this form of productive inefficiency have been relatively small to date[8] .

The AER describes a situation in which congestion occurs in a region, generators behind the constraint engage in "disorderly bidding" to maximise dispatch against a high regional reference price, one or more of these generators rebid their ramp rates to the minimum value to avoid being constrained down, and counter price flows occur on the interconnector to the neighbouring region as energy is forced into it to avoid violating ramp rate constraints.

8 TFR, p.6.

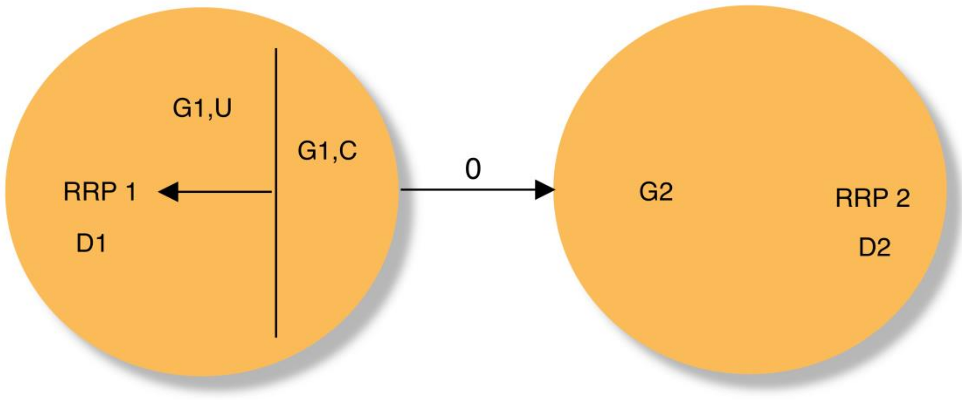
The situation is depicted in Figure 1 where generation in region 1 is designated as unconstrained (G1,U) and constrained (G1,C). AEMO's dispatch calculation results in reference prices for each region RRP 1 and RRP2 where RRP1 > RRP2 and a counter price flow of GE from region 1 to region 2. Demand in region 1 is D1 and in region 2 D2. From which it is clear that D1 = G1,U + G1,C – GE and D2 = G2 + GE.

Figure 1 **Congestion and counter-price flows - 1**



We consider another case (Figure 2) where the ramp rates of generators behind the constraint in region 1 are not rebid and that this results in a dispatch outcome that removes the counter price flow (G1,C is constrained down by the quantity GE). In this case D1 = G1 U + G1 C, D2 = G2 and RRP1 > RRP2.

Figure 2 **Congestion and counter-price flow - 2**

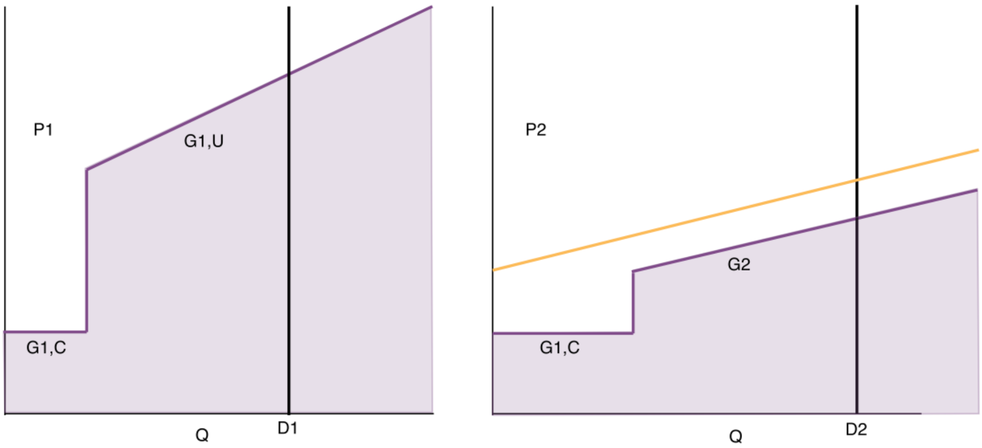


Given that the price is high in region 1 the flow in the first case will inevitably be counter price. This is because generation in region 2 cannot be exported to region 1 because it is competing with G1 C behind the constraint.

The occurrence of counter price flows does not mean that the cost of meeting aggregate demand is necessarily higher by allowing the export of G1 C to region 2.

This is evident in Figure 3 which shows the supply curves for each region. The red supply curve in region 2 is the supply curve for the case where no energy is exported from region 1 to region 2.

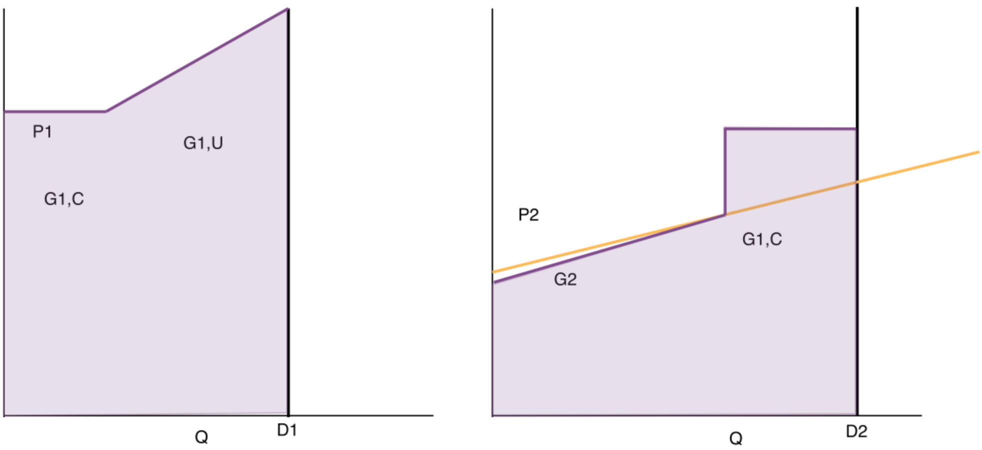
Figure 3 **Cost of supplying aggregated demand - 1**



In this case the flow is counter price but generation that would be constrained off in region 1 if it were not interconnected should be dispatched into region 2 as its cost is lower than the cost of generation in region 2. Generation in region 2 cannot flow into region 1 because it is behind the constraint. Under a least cost dispatch, counter price flow will occur anyway unless AEMO prevents it by clamping.

In this case preventing the export of G1 C to region 2 would result in a higher cost of supply. However depending on the relative supply costs of G1 C compared to G2, allowing the export of G1 C to region 2 could result in a higher cost of meeting aggregate demand as shown in Figure 4. Again the red supply curve in region 2 is the supply curve for the case where no energy is exported from region 1 to region 2.

Figure 4 **Cost of supplying aggregated demand - 2**



In this case the flow is counter price but generation that would be constrained off in region 1 if it were not interconnected would not be dispatched into region 2 as its cost is higher than the cost of generation in region 2. By allowing the export of G1 C to region 2, the cost of supplying total demand D1 + D2 is higher.

It is not the case therefore that productive efficiency losses are necessarily associated with counter price flows. In fact in many cases the effect will be immaterial.

It is not valid to conclude that changes in the merit order of dispatch necessarily imply productive efficiency losses. While dispatch outcomes in the NEM might be expected in many cases to conform with the "merit order of dispatch" as the stacking of generator dispatch offers in increasing order of offer price, the optimisation of dispatch in the NEM is a co-optimisation of dispatch in the energy and ancillary services markets subject to a variety of constraints. The AER has not provided an estimate of productive efficiency losses attributable to rebidding of ramp rates.

Two relevant modelling studies concerned with projecting productive efficiency in the context of congestion pricing arrangements that remove the incentives for disorderly bidding are those undertaken by Intelligent Energy Systems (IES) for AEMO[9] and by Roam Consulting for the AEMC[10]. IES concluded that "the economic efficiency benefits of the SACP model in terms of saved fuel costs are very small" (p.25). Roam Consulting concluded "the observed cost increase resulting from disorderly bidding should remain small compared with total system costs" (p.80).

4.4 Effectiveness of interconnectors

The AER considers that "disorderly bidding greatly reduces the effectiveness of interconnectors making it more difficult for retailers and generators to hedge across region boundaries"[11]. In general, while the inter-regional revenues obtainable through settlement residue auctions provide a degree of risk mitigation to the larger generators and retailers, their non-firmness renders them an inadequate hedging instrument for smaller retailers without diversified supply portfolios. However disorderly bidding is held to "reduce the effectiveness of interconnectors", the removal of the effect is not likely to change the status of the inter-regional revenues from a form of risk mitigation to an effective inter-regional hedge. The lack of "firmness" of the "existing inter-regional product [12] is referred to by the AEMC in the context of inter-regional access under the Optional Firm Access Model . This lack of firmness is cited by the AEMC as "one of the key problems with the current transmission arrangements".

The AER considers that inter-regional trade will be assisted should its rule change be implemented and refers to a reduction in counter-price flows on interconnectors. The history of the NEM shows that there is considerable basis risk in buying in one region and selling in another. The availability of settlement residues associated with the inter-regional interconnectors at best provides risk mitigation. As an inter-regional hedge, settlement residues are non-firm because they depend on the interconnector flow. The biggest risk is always when flow is constrained (at full rated capacity or below) and inter-regional prices separate markedly. The implementation of AER's rule change proposal is not likely to have a material impact on the price and availability of hedges for inter-regional trading.

The AER has identified "high cost recent examples" of counter price flows in the NEM and reported associated negative settlement residues[13].

9 Modelling the SACP (Shared Access Congestion Pricing) Model, IES 23 April 2012

10 Modelling Transmission Frameworks Review, Roam Consulting 28 February 2013.

11 Request for Rule Change, p.1

12 TFR p.75.

13 Special Report – The impact of congestion on bidding and inter-regional trade in the NEM, AER, December 2012, p.17.

The AER has provided also examples of where the rebidding of ramp rates in concert with rebidding generation contributed to counter price flows. However the AER has not provided an estimate of the effect which is attributable to the rebidding of ramp rates.

AER has exhibited some trend analysis of residues and SRA proceeds[14] and has made considerations on that basis. There are three relevant questions. The first is whether the efficacy (or firmness) of settlement residues as an inter-regional hedge has reduced over time. The second is, if so, what has been the role of rebidding of ramp rates. But the third is the reliance participants have had on SRAs anyway. It is doubtful that they ever occupied a major role in the hedge portfolios of other than the major retailers. If so a decline in the value of SRAs has no effect on hedging costs. This third question is taken up in Chapter 5.

14 Ibid, p.20.

5 Inter-regional trading in the NEM

5.1 Spot and contract markets

The NEM provides a mandatory gross pool through which, with minor exceptions all electricity is traded. This means that bilateral contracts between generators and retailers (which existed prior to the NEM as bulk supply and power purchase agreements, and in net pool markets such as the wholesale market in Western Australia are settled without reference to spot prices) must take the form of financial contracts referenced to regional electricity spot prices.

In discussions about the NEM, disagreements occur as to which of these markets – the spot market or the contract market is the primary market. To avoid confusion it is necessary to be clear about the sense in which one of these markets might be regarded as primary. There is a simple sense in which the spot market is the primary market which arises directly from the mandatory gross pool aspect of the market design. The point is often made that electricity is an unusual commodity because it cannot be stored and therefore must be consumed at the instant it is supplied. For this reason the electricity spot market is implemented as a close to real-time market with five minute dispatch intervals and prices and regional references prices calculated for each half-hourly trading interval.

Electricity as a physical commodity is the electricity traded each half-hour in the pool. Electricity cannot be purchased physically for future delivery. By necessity then, electricity contracts take the form of financial derivative contracts. The term derivative is used because the contract derives its value from an underlying asset, in this context physical electricity traded in the pool. This suggests that the spot market is the primary market and the contract market the secondary or derivative market.

But there is an alternative way of thinking about things. Electricity generators, retailers and end users are not primarily interested in trading electricity on the half-hourly NEM interval settlement basis. Rather they are interested in multi-year electricity supply and purchase contracts. This was the case prior to the implementation of the NEM and has continued to be the case after the implementation of the NEM - of course with the NEM enabling competition in the provision of these contracts. Consistent with this view, the market in these contracts is the primary market and the electricity spot market simply an access arrangement to allow for the dispatch of generation on a competitive basis.

As explained, the NEM design has necessitated these contracts assuming the form of financial contracts. These contracts also tend to be referred to as hedge contracts as they have the effect of converting a market participant's exposure from floating to fixed price. However they are also the means of synthesising the old-style multi-year electricity supply or purchase contracts. The fact the NEM has always been relatively highly hedged or contracted does say something about risk in the spot market and participants' risk preferences. But it also says that participants prefer to trade electricity largely in the form of multi-year contracts. On this view the multi-year contract market is the primary market and the electricity spot market a means for the competitive dispatch of generation.

The most traded electricity derivative contract in the NEM is the fixed for floating price swap. The seller of the swap pays the floating price and receives the fixed price. The buyer of the swap pays the fixed price and receives the floating price.

Generators and retailers in the NEM are natural counterparties to this swap as sellers and buyers respectively as it allows both to achieve a fixed price in respect of the notional swap quantity once the payments they receive under the swap are applied to their physical positions in the NEM's spot market. Further, by locking in a fixed price for the duration of the swap contract, to the extent to which the generator is able to be dispatched to the notional quantity, and the swap quantity matches the retailer's customer load, both generator and retailer lock in a gross margin for their businesses which is their commercial objective. They are effectively insulated from changes in electricity spot and contract prices and are therefore not concerned with the "mark-to-market" value of the swap contract which is the primary concern of any speculative traders of these contracts.

In general a generator will want to maximise the quantity of multi-year supply contracts it enters into subject to there being a sufficiently high probability of having sufficient generation dispatched against the aggregate contract quantity - not strictly at all times but when spot prices are very high. There are two risks to consider here. The first is the availability of sufficient generation capacity within the generation portfolio. The second is the possibility of being constrained-off by transmission constraints within the region in which the generator is located. At this point it is worth noting that the NEM is a regional rather than a nodal market.

5.2 Inter-regional and intra-regional constraints

At the present time the NEM's regions are defined in terms of jurisdictional boundaries. The transmission links between regions which are referred to as inter-regional interconnectors are generally weaker than intraregional transmission links in that they are more frequently constrained. This is unsurprising in view of state-level responsibility for the development of the regional power systems prior to the NEM. Such interconnection that was in place prior to the NEM served to support some limited sharing of capacity and energy interchange. While the introduction of the NEM has resulted in increased utilisation and some upgrading of the transfer capacity of existing interconnectors, and the construction of new interconnectors both as market and prescribed network services, in general a generator will not seek to sell supply contracts outside of the region in which it is located. This is because

1. the potential price differences between regions are too large to take on such a position without managing or mitigating the locational basis risk and
2. inter-regional settlement residues, assuming they can be accessed through the periodic auctions, are not sufficiently firm to adequately mitigate this risk.

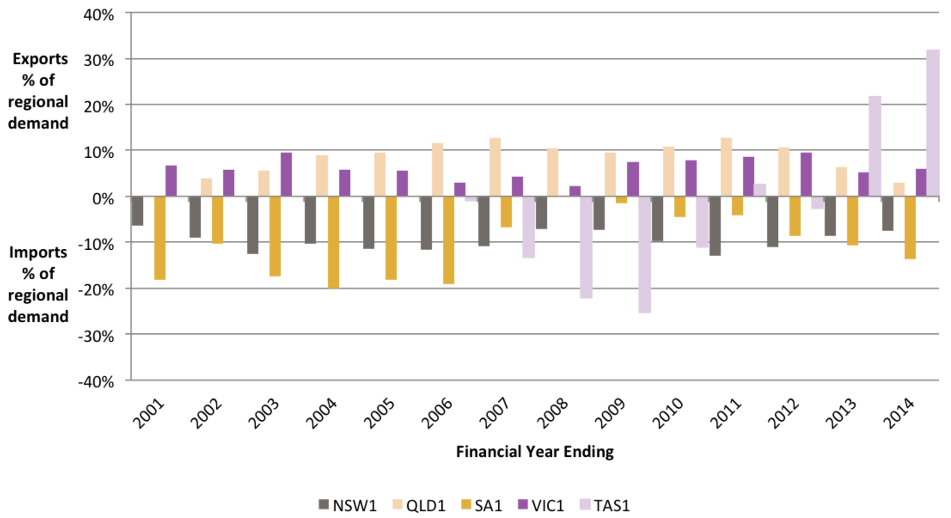
Within a region a generator might be subject to transmission constraints. As explained these can be expected to bind relatively less frequently than inter-regional transmission constraints. In the NEM's regional market, intraregional transmission constraints can have the effect of preventing a particular generator from being fully dispatched in accordance with its dispatch offer. If the regional reference price is relatively high this typically means it will be dispatched at a lower level than the level it desired to be dispatched at (it is constrained down). However, this generator will still receive the regional reference price in respect of its lower dispatch quantity. In a nodal market the risk would be greater. This is because not only would the transmission constraint result in the generator being constrained down, but the nodal price received by the generator for what it does generate would be typically much lower than the regional reference price (or more correctly its nodal equivalent) due to increased competition in generation behind the constraint.

For these reasons then 1) the fact that typically intraregional constraints bind less frequently than inter-regional constraints and 2) the fact that generators located in a region receive the regional reference price (albeit adjusted by a static marginal loss factor), generators within a region have firmer access to their regional reference price than generators in other NEM regions. This has important implications for the impact of arrangements for congestion management on the efficiency of the spot and contract markets.

5.3 NEM regional imports and exports

Figure 5 shows imports and exports of energy from each of the NEM's regions expressed as a percentage of regional demand. In general energy imports and exports have represented less than 10% of regional demand. The exceptions are South Australia which prior to experiencing significant development of its wind energy potential regularly imported some 20% of its requirements from Victoria, and Tasmania which imported more than 20% of its requirements to address low hydro-electric storage levels from 2007 to 2010, and high exports in 2013 and 2014 to take advantage of carbon price uplifted wholesale electricity prices in Victoria.

Figure 5 **NEM regional imports and exports**

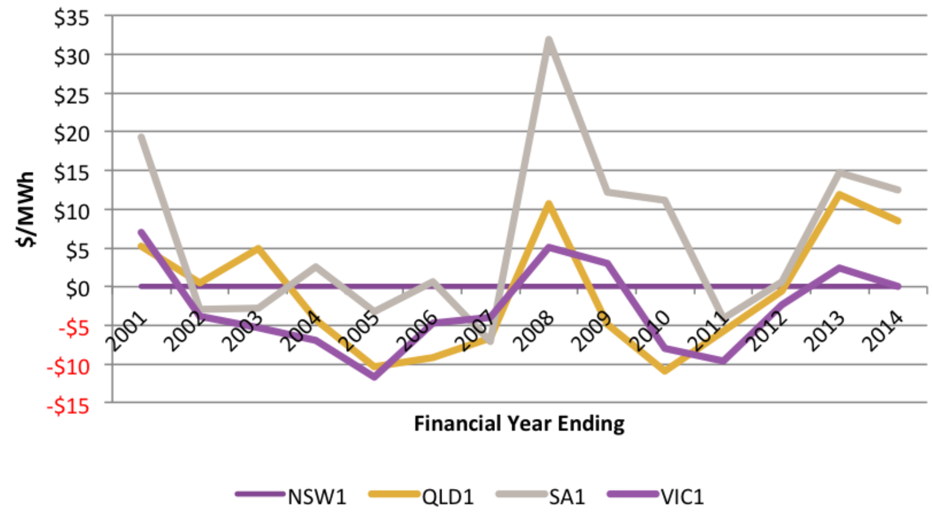


With the exception of Hydro Tasmania, which has the means to support a contract and retail position in Victoria using its generation in Tasmania and the inter-regional revenues it holds on the Tasmanian – Victorian interconnector Basslink, it is doubtful that the electricity imports and exports between the major NEM regions – Queensland, New South Wales and Victoria, which are relatively small compared to regional demand are evidence of generators contracting in other regions. Indeed, if it is supposed that the NEM is 90% contracted, the energy transferred across interconnectors is most probably largely "balancing energy".

5.4 Inter-regional price differences in the NEM

Inter-regional price differences in the NEM are potentially too large to allow a generator to generate in one region and sell a contract in another. Figure 6 shows average annual regional spot prices in the NEM since 2001 relative to New South Wales.

Figure 6 **Average annual regional spot price differences in the NEM**



Furthermore, inter-regional settlement residues, assuming they can be obtained by the generator, are not sufficiently firm to provide substantial mitigation of this risk. As mentioned the exception to this may be Hydro Tasmania which not only holds the inter-regional residues of Basslink and has the right to instruct Basslink to submit network dispatch offers, but by virtue of its dominant position in the Tasmanian region also exercises substantial control on the direction and quantum of flow on the interconnector.

While the South Australian average annual spot price has experienced marked separation from the other NEM average annual spot prices, the differences between the spot prices of the larger NEM regions also show at times significant variation. Over the period shown, the annual average Queensland spot price has varied from the New South Wales price in the range of -$11 to $12/MWh and the Victorian price in the range of -$12 to $7/MWh.

5.5 Financial firmness of inter-regional interconnectors

Suppose a generator is located in NSW and has entered a contract with strike price S referenced to the NSW spot price PNSW with notional quantity Q. Assuming the generator generates quantity Q it receives spot market revenue of Q x PNSW and pays its contract counterparty Q x (PNSW - S). Its net revenue is Q x S.

Suppose that instead the generator enters a contract with strike price S referenced instead to the QLD spot price PQLD with notional quantity Q. In this case, again supposing the generator generates quantity Q it receives as before spot market revenue Q x PNSW but pays its contract counterparty Q x (PQLD - S). If PNSW> PQLD then it earns from the spot market more than the floating payment to its counterparty. In general this implies that the flow on the inter-regional interconnector is from Queensland to New South Wales (lower price region to higher price region). If PQLD > PNSW, what the generator earns from the spot market is lower than the floating payment to its counterparty and the generator will want to hedge or mitigate this exposure. It can do this most directly by swapping the amount Q x PNSW which it receives for generating in the spot market for the amount Q x PQLD which is the amount it would receive if it were located in Queensland.

An ideal counterparty would be a Queensland generator which wished to sell a contract referenced to the NSW price. It is doubtful that presently in the NEM such circumstances are common. The purchase of units of the inter-regional settlement residues that accrue during times of flow from NSW to QLD on the inter-regional interconnector would provide some mitigation of the risk. However the quantity is not firm because it depends on the flow on the link. Figure 7 and Figure 8 show the financial firmness of the Victoria – NSW and NSW – QLD inter-regional interconnectors. The firmness is a ratio calculated in financial rather than quantity terms. It is calculated as the ratio of the value of the settlement residues to the payment that would be received if the price differences at times of flow from one region to another were always calculated in respect of the full notional capacity of the interconnector.

Figure 7 **Financial firmness of interconnectors – VIC-NSW**

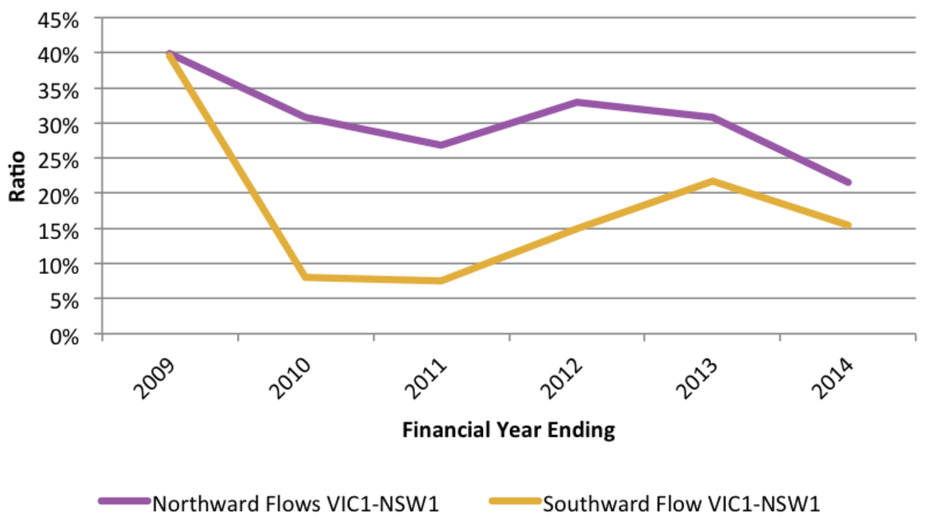
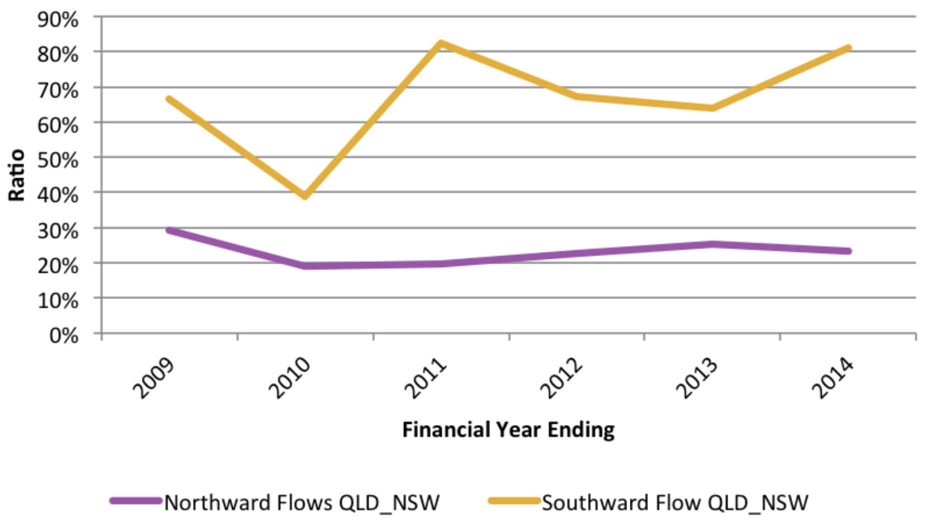


Figure 8 **Financial firmness of interconnectors – NSW-QLD**

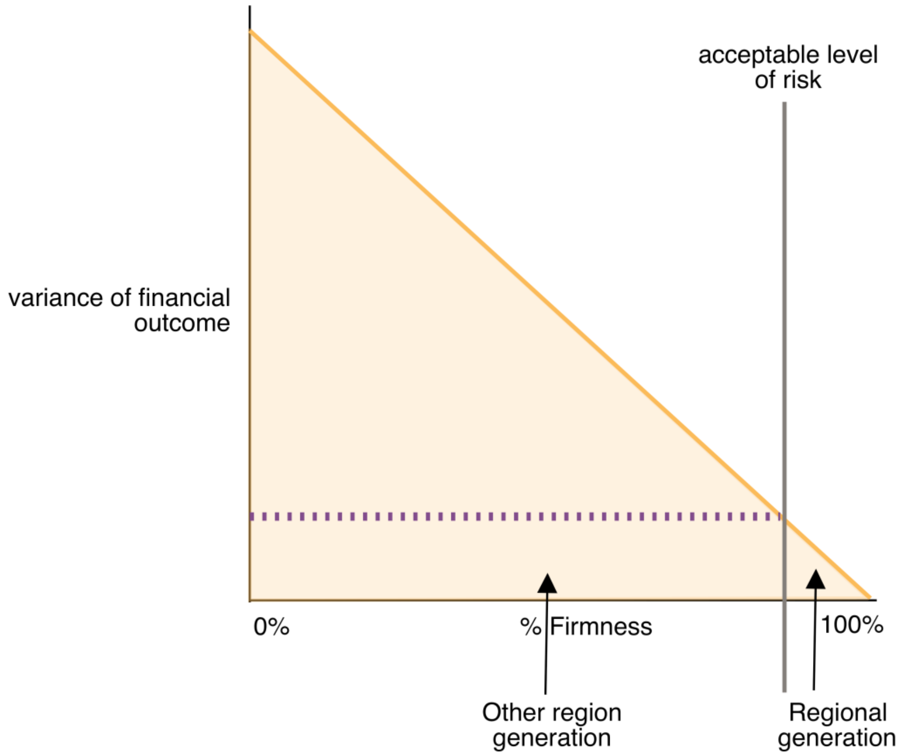


5.6 Congestion and the contract market

In considering the impact of the proposed rule change on the contract market it is necessary to consider separately the effect on generators in the region where congestion occurs and generators in other regions. Forcing flexible generators to be constrained off by requiring them to make their maximum ramp rates available to AEMO may, as AER claims, reduce the incidence of counter-price flows and improve the firmness of inter-regional settlement residues. However it will also have the effect of reducing the firmness of access of the affected generators in the region to the regional reference price. The net effect is that the supply of firm contract quantity within the region is likely to be reduced. This is because firm contracts will generally be offered only when backed by sufficiently high firmness of supply.

This is shown in Figure 9. A reduction in the firmness of relatively firm access to the regional reference price may result in contract quantity being withdrawn or offered with a substantially increased price. On the other hand, an increase in the firmness of relatively non-firm inter-regional settlement residues is unlikely to support a firm contract offer.

Figure 9 **Firmness of access to regional reference price**



With fully firm access to the regional reference node there will be no variance in target financial outcome. With increasing non-firmness, the variance will increase as the distribution of financial outcome is a mixture of the zero variance associated with full firmness and the variance of spot prices. There will generally be an acceptable level of risk expressed in terms of a low variance of financial outcome (and corresponding high level of firmness) at which the generator will be prepared to offer a firm contract at the regional reference node.

In general, this acceptable level of risk is met for generators located within the region. However it is not likely to be met for generators located outside a region with access to inter-regional revenues of marginally improved firmness.