Electricity Report

23 February to 1 March 2014

AUSTRALIAN ENERGY REGULATOR

Introduction

The AER is required to publish the reasons for significant variations between forecast and actual price and is responsible for monitoring activity and behaviour in the National Electricity Market. The Electricity Report forms an important part of this work. The report contains information on significant price variations, movements in the contract market, together with analysis of spot market outcomes and rebidding behaviour. By monitoring activity in these markets, the AER is able to keep up to date with market conditions and identify compliance issues.

Spotlight price spikes in Queensland during Summer 2013-14

Background

The Queensland region has experienced significant price volatility in the recent past, for various reasons. In our December 2012 report, *The impact of congestion on bidding and inter-regional trade in the NEM*, we wrote about volatile prices and significant negative settlement residues associated with congestion on the transmission lines between Calvale-Wurdong and Calvale-Stanwell during 2011 and 2012.

Similarly, in our Electricity Weekly report for the week 25 to 31 August 2013[1], we wrote about volatility in Queensland in mid to late August 2013. Our analysis revealed that high prices during this period were driven by relatively small increases in five-minute demand which was unable to be met by low-price generation in Queensland or imports in the relevant five minutes. This required the dispatch of generation priced at, or close to, the market price cap. These spikes in dispatch price occurred at relatively low levels of demand (around 6000 MW).

From December 2013 to the end of February 2014, spot price volatility was again a feature of the Queensland region, this time as a direct result of the rebidding strategies of some Queensland generators. Over this period (the summer period) the 5-minute price exceeded $1000/MWh on 50 occasions driven primarily by generators rebidding. That is, with very little warning, generators in Queensland were submitting rebids that shifted large quantities of capacity from low prices to prices greater than $10 000/MWh. Given the prevalence of the volatility and the potentially adverse impact this can have on the market, we consider it appropriate to explore the events in more detail as part of this weekly spotlight.

Summary / Conclusion

In analysing the circumstances surrounding these high priced periods we found:

- CS Energy's rebidding strategy triggered 34 of the 50 high price events in Queensland in the summer period.
- This strategy was occurred repeatedly across the summer period.

[1] This report can be found at http://www.aer.gov.au/node/18855

- The strategy relied on rebidding late in the trading interval and shifting capacity into price bands close to the market price cap, resulting in very little, or no, capacity being offered at prices between $500/MWh and $10 000/MWh.
- The most common reason given for these rebids late in the trading interval related to QNI being constrained, despite these constraints binding a number of dispatch intervals before the rebid and/or being flagged for some time in the predispatch systems. We note that flows north into Queensland can be limited due to a system normal constraint and can be as low as 200 MW depending on the output of Kogan Creek Power Station.
- In December and early January, the volumes and prices rebid by CS Energy caused significant changes to the merit order in the region. Consequently, the dispatch engine (NEMDE) set new targets, and other generators were ramped up while the CS Energy generators were ramping down. The CS Energy portfolio includes the Wivenhoe and Gladstone power stations which provide the vast majority of the ramping capability in the region and as such to meet the new targets, much higher priced capacity was dispatched to meet these new targets.
- Towards the end of the summer, some other market participants were also rebidding available capacity from low to high prices at times that sometimes coincided with those of CS Energy. Consequently, there was even less low and medium priced capacity available and prices spiked more frequently. As a secondary effect the widespread rebidding reduced the change to the merit order and less ramping appears to have been required.
- Generally the normal day ahead and trading interval pre-dispatch forecasts did not predict the prices spikes. The price spikes were of a short duration (5 or 10 minutes) and other market participants, in particular fast start plant and loads, could not respond. Depending on their offer price, the fast start generators may have received start instructions but, given the very short duration of the price spike they elected to either operate for longer periods in case price spikes occurred or rebid to higher prices to avoid the start.

The average price in Queensland for the summer period was $68.77/MWh. If the 50 short-term price spikes are excluded, the average price for the period drops by $14.66 to $56.10/MWh. As we have discussed in previous reports on the volatility in Queensland, variability in spot prices can influence forward contract prices which ultimately flow through to end consumers' bills.

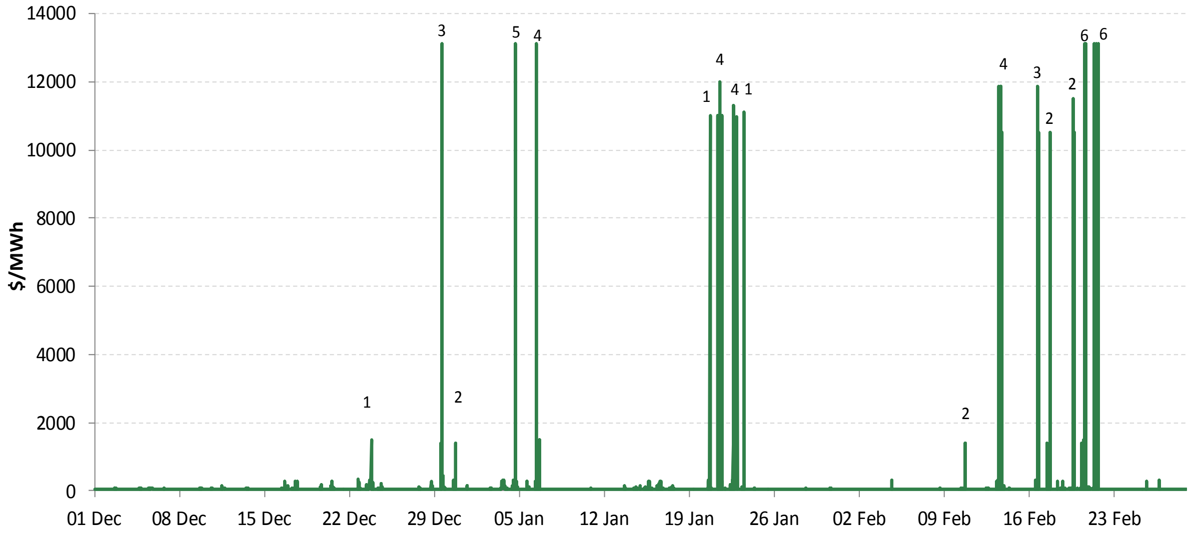
The behaviour highlighted in this analysis raises a number of concerns. Rebidding that produces short term price spikes (5 or 10 minutes in duration) close to the time of dispatch and/or late in a trading interval effectively precludes a competitive reaction from some generators and loads. Efficient market dispatch also relies on quality forecast information being available to all participants. The circumstances and rebidding behaviour identified in Queensland during the summer period makes the information contained in the forecasting systems less useful, compromising the efficiency of dispatch and resulting in artificially high spot prices.

The AER is examining whether rebidding during this period is consistent with the requirements of the Rules.

Analysis

Our analysis centred on the 50 occasions over the summer period where the dispatch price exceeded $1000/MWh as shown in Spotlight Figure 1. This pricing value was chosen as it represents a significant departure from the typical market price. The number of dispatch intervals where the spot price exceeded $1000/MWh is shown next to the price spikes.

Spotlight Figure 1: Dispatch price ($/MWh) in Queensland for the summer period



Our analysis considered a number of factors that could foreseeably contribute to the high prices. These included: demand, generator availability, rebidding, interconnector capability, and generator ramp rates.

Demand and Generator Availability

Demand during the period was as would have been expected given the weather conditions. Similarly, other than the reductions listed in the medium and short term projected assessment of system adequacy (MTPASA and STPASA), generator availability was consistent with expectations.

Rebidding

As the first step in our analysis we examined the relevant rebids. We observed that:

1. Timing and magnitude of the rebids was important.
   - many rebids became effective[2] close to the time of the high price
   - many rebids were made late in the trading interval
2. most rebid reasons related to the QNI interconnector being constrained or forecast to be so
3. the rebidding was repeated frequently.

Analysis of observations

1. Timing and magnitude analysis

The timing of the rebids with respect to the time that the high price is set is an important consideration as it affects the amount of forward notice that other participants have of a change in conditions. Two aspects of the timing; the time prior to dispatch and the time that the rebid occurs within the trading interval, are both important factors to consider.

For dispatch prices greater than $1000/MWh and where the rebid volume was greater than 100 MW[3], Spotlight Table 1 shows how many minutes prior to dispatch the rebids became effective and the average magnitude[4] of the rebid. Only events where the rebids were made within the trading interval were included[5], as these reduce the time for forecast systems to provide notice of the change to

[2] A bid becomes "effective" when it is first included in the process that determines pricing and dispatch outcomes that is when it is first included in the national market dispatch formulation.

[3] A rebid volume of $100/MWh was chosen to represent a significant volume change.

[4] Calculated as a simple average of the quantities rebid.

[5] One event was excluded where the rebids became effective more than 30 minutes before the high price.

participants and may have reduced the opportunity for the conventional range of generators and loads to react.

Spotlight Table 1: Timing and volume of rebid by participant for the summer period

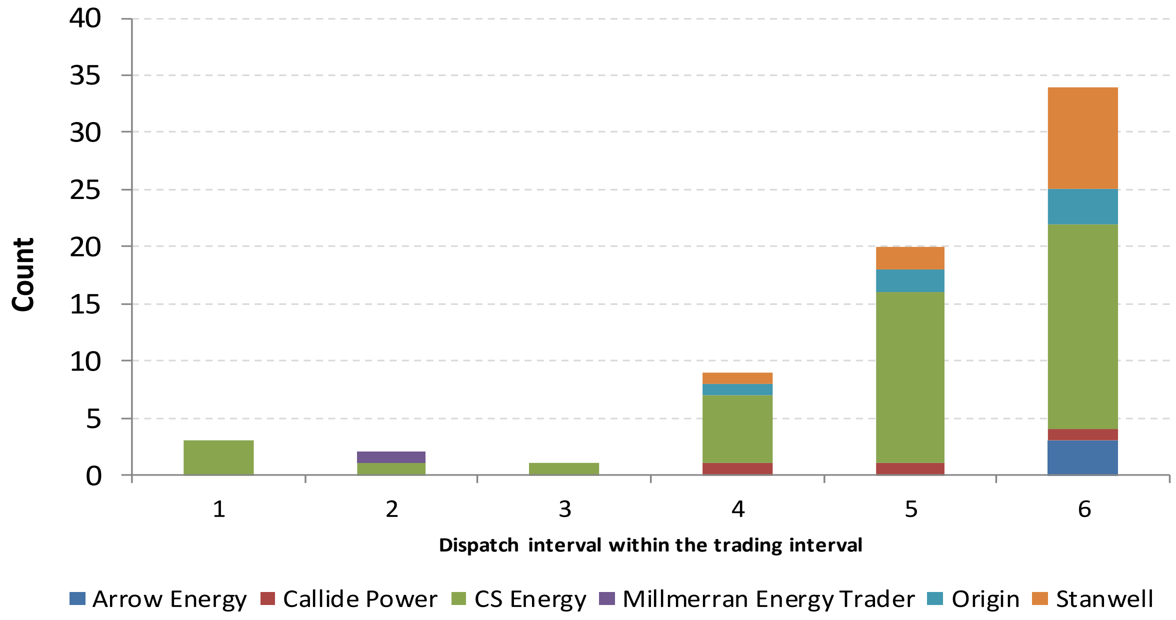
	Arrow Energy		Callide Power		CS Energy		Millmerran Energy Trader		Origin		Stanwell	
Minutes before the high price	No.	Ave Cap (MW)	No.	Ave Cap (MW)	No.	Ave Cap (MW)	No.	Ave Cap (MW)	No.	Ave Cap (MW)	No.	Ave Cap (MW)
0	3	141	2	113	34	305			3	137	9	284
5					6	507			2	113	3	414
10			1	160	3	223			1	175		
15					1	120						
25							1	110				
30					1	790						
all periods	**3**	**141**	**3**	**129**	**46**	**343**	**1**	**110**	**6**	**135**	**12**	**317**

- On 34 of the 50 occasions when the dispatch price exceeded $1000/MWh, CS Energy's rebids became effective in the same dispatch interval as the high price occurred (denoted by the 0 in the "Minutes before the high price" column). That is, these rebids significantly contributed to the high price. The next highest was Stanwell with nine occasions (both values are highlighted in red)
- CS Energy and Stanwell rebid the largest average volumes into high price bands - 343 MW and 317 MW respectively. This corresponds to approximately 10 per cent of the total capacity of their portfolios. – (highlighted in blue)
- the 305 MW (highlighted in orange) average capacity rebid by CS Energy 0 minutes prior to dispatch has a maximum rebid of 625 MW across the portfolio.
- on one occasion, 5 minutes prior to dispatch, CS Energy shifted 1100 MW in their rebid (highlighted in green). The next highest volume rebid by CS energy was 790 MW, 25 minutes prior to dispatch.

Rebidding late in a 30-minute trading interval arguably reduces the reliability of market forecasts by causing a change in price close to dispatch, and effectively reduces the opportunity for a response from other participants. This problem is exacerbated by the 5-30 issue where market dispatch provides 5 minute prices and dispatch instructions but settlement is calculated every 30 minutes based on the average of the six 5-minute dispatch intervals in the trading period. While this approach may be profitable for some participants it may impose costs on others and on consumers by increasing the wholesale market price. It may also potentially drive a greater need for risk management instruments that will also result in higher prices to consumers.

We examined when within a trading interval rebids became effective. Rebids became effective in the next available dispatch interval after the rebid is submitted, and as such it is largely controllable by the participant. Spotlight Figure 2 shows the timing of the rebids. If the rebid became effective in the first dispatch interval of the trading interval it is included in the "1" column, "2" if it was effective in the second dispatch interval, etc.

Spotlight Figure 2: Effective dispatch interval within the trading interval for the rebids



The figure shows that most of the rebids were made within the last three dispatch intervals of the relevant trading interval, potentially reducing the number of, and opportunity for, participants to effectively and viably react to the high price to those already operating.[6] It also reinforces the relative frequency of CS Energy rebids compared to the other participants.

Assuming the interconnector remained constrained; there are two potential groups of market respondents to these price spikes:

- Fast start plant, such as gas turbines, typically price their capacity close to the market price cap. As the price spikes were not forecast, fast start plant may have received start signals. However because of the time taken to bring these machines on line[7] they would be unlikely to be operating before the end of the trading interval in which the high price occurred. They would not therefore receive appropriate compensation for their generation.
- Other generators with sufficient ramp rate may have had:
  - little head room before they reached their maximum output level or been dispatched into a high priced band
  - may have been trapped or stranded by other operational mechanisms.
  - Been ramp rate constrained and not set price.

The rebidding behaviour by CS Energy effectively changed the market conditions in Queensland. As the summer progressed, many participants adapted their behaviours to suit these new conditions. Some generators elected to rebid capacity in a similar manner and time to CS Energy while others chose different approaches. The fast-start plant in particular appear to have elected to either:

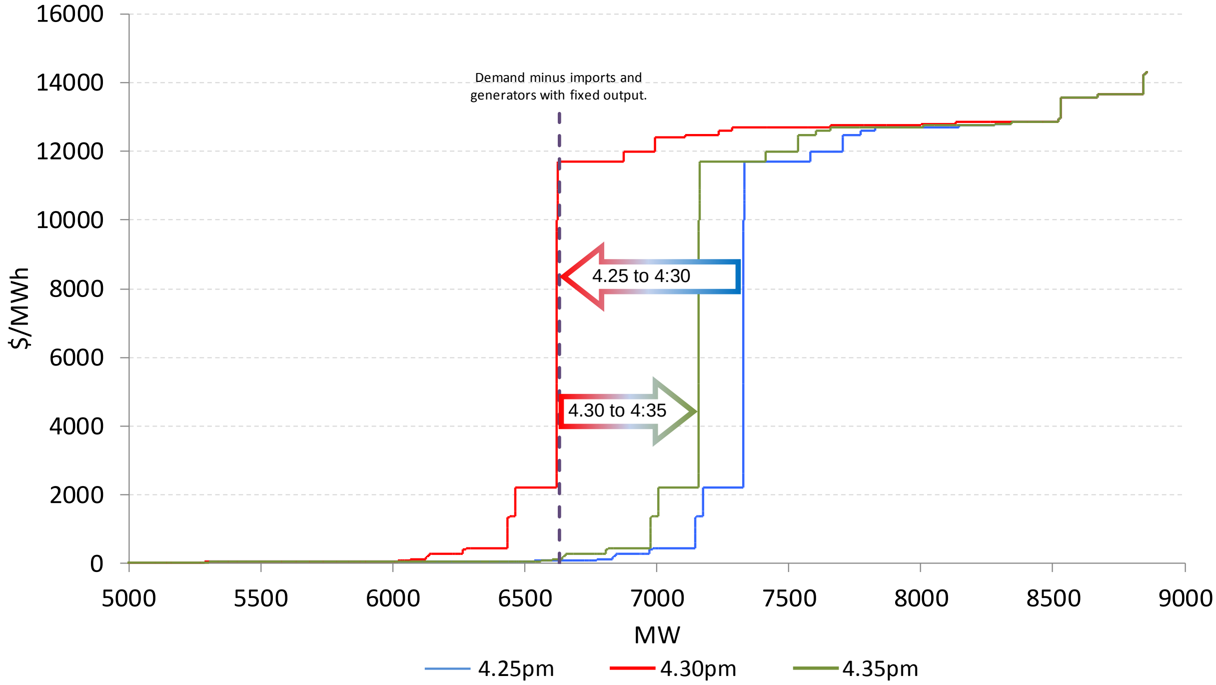
- operate for more hours at prices that may be less than their operating costs, in case a high price events occurred, or
- increase their offer prices closer to the market price cap.

[6] Fast start plant that is not already running

[7] This is known as a Fast Start Inflexibility Profile – each fast start plant is required to nominate the time it will take to start, get to operating speed, synchronise and get to minimum load.

The rebidding and subsequent response strategies have had a significant impact on the Queensland supply curve for the few dispatch intervals for which the rebids apply. Spotlight Figure 3 shows the effect that rebidding had on the supply curve in Queensland on 13 February for the 4.25 pm, 4.30 pm and 4.35 pm dispatch intervals. The Queensland demand curve (less QNI imports) is represented by the vertical dotted line. This day was chosen as it was relatively representative of the change to the supply curve before during and after the high price events.

Spotlight Figure 3: Queensland supply curve over three dispatch intervals - 13 February 2014



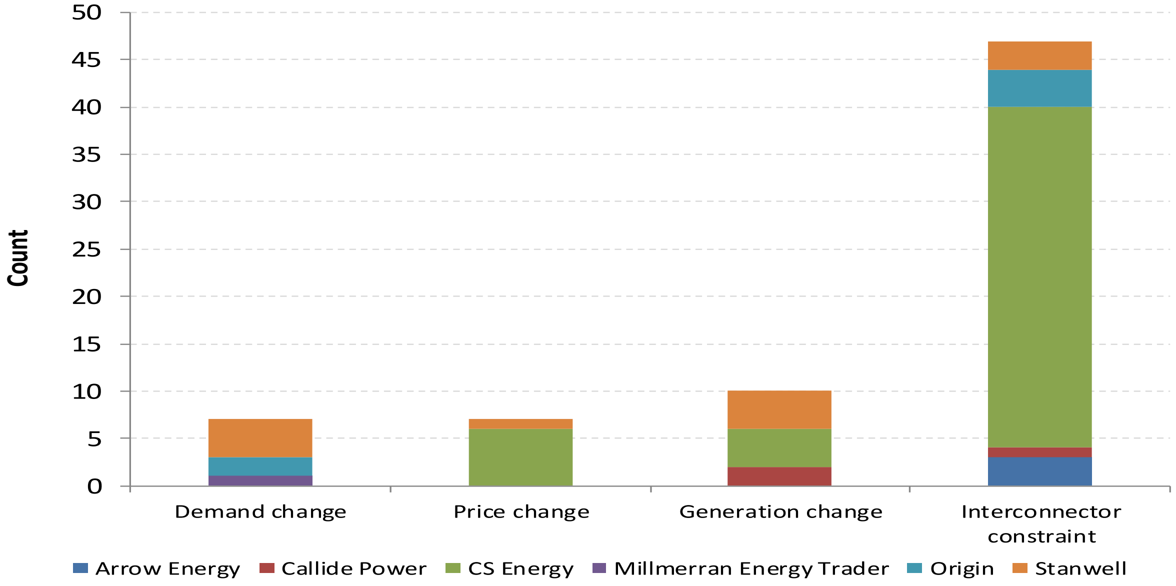
In this figure three participants (CS Energy, Callide Power[8] and Stanwell) rebid a total of around 700 MW of capacity from low prices to high prices which became effective for the dispatch interval ending 4.30 pm (last dispatch interval in the 4.30 pm trading interval). The impact of the rebidding is represented by the three supply curves. The price went from $84/MWh at 4.25 pm to $11 851/MWh at 4.30 pm then down to $120/MWh at 4.35 pm when the rebids were no longer effective. Clearly, in this case, a smaller quantity of capacity rebid would still have led to a high price but not one greater than $10 000/MWh.

2. Rebid reasons

Participants are required by the rules to submit a brief verifiable and specific reason whenever a rebid is submitted. Participants are obliged to honour their original offers and rebids if the material conditions and circumstances upon which the offer or rebid were based remain unchanged. We examined all relevant rebids and associated reasons to ensure they were consistent with the rules. That review is ongoing. Most of the rebid reasons during the period fell into four main categories, as shown in Spotlight Figure 4.

[8] CS Energy and InterGen each have control of 50% of the output of Callide Power

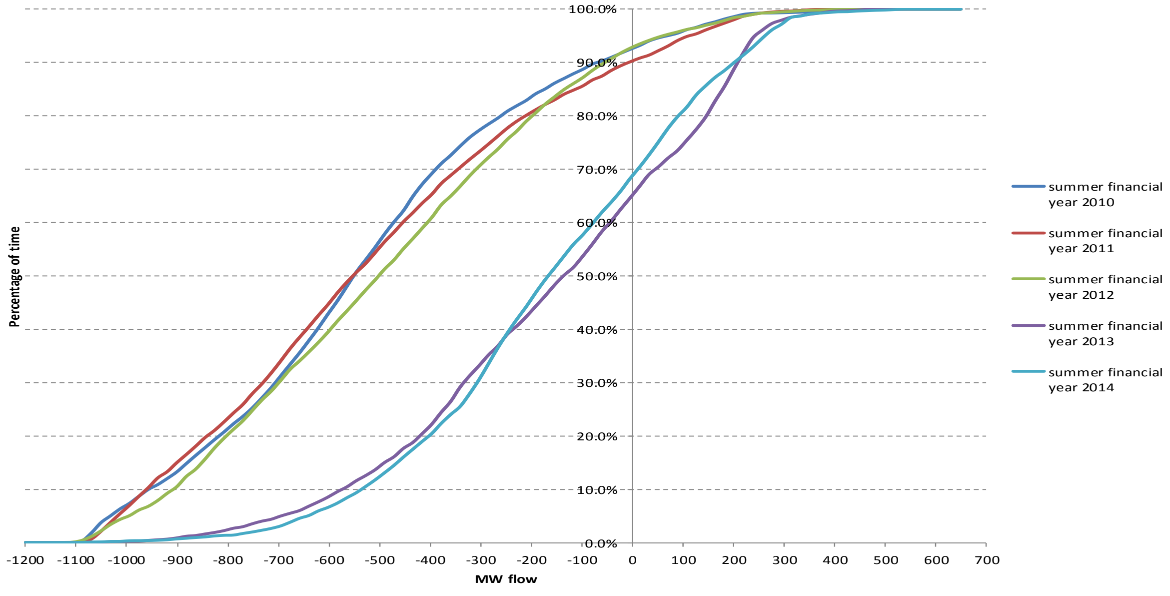
Spotlight Figure 4: Rebid reasons within a trading interval



Spotlight Figure 4 shows that most rebid reasons were related to constraints, or forecast constraints on the Queensland to New South Wales interconnector (QNI). There appears, however, to be little correlation between when the conditions related to the interconnector materially changed, or were forecast to change, and when rebids were submitted. Our analysis showed that on some occasions the interconnector was forecast to constrain some hours prior to dispatch, on others the network constraint appeared as close as in the preceding interval.

The system normal constraints that are important in this case are those that limit imports into Queensland across QNI to prevent voltage collapse in New South Wales in the event of the loss of the Kogan Creek generator. We determined that the flow duration curves for the 2012/13 summer period and those for the 2013/14 period were largely similar. Spotlight Figure 5 shows the flow duration curves for the summer periods for the last 5 years. The shift of the 2013 and 2014 curves to the right from the 2010, 2011 and 2012 financial years reflects a reduction in imports into Queensland following the withdrawal of generating capacity from the region.

Spotlight Figure 5: flow duration curve for QNI for summer periods over the last five years

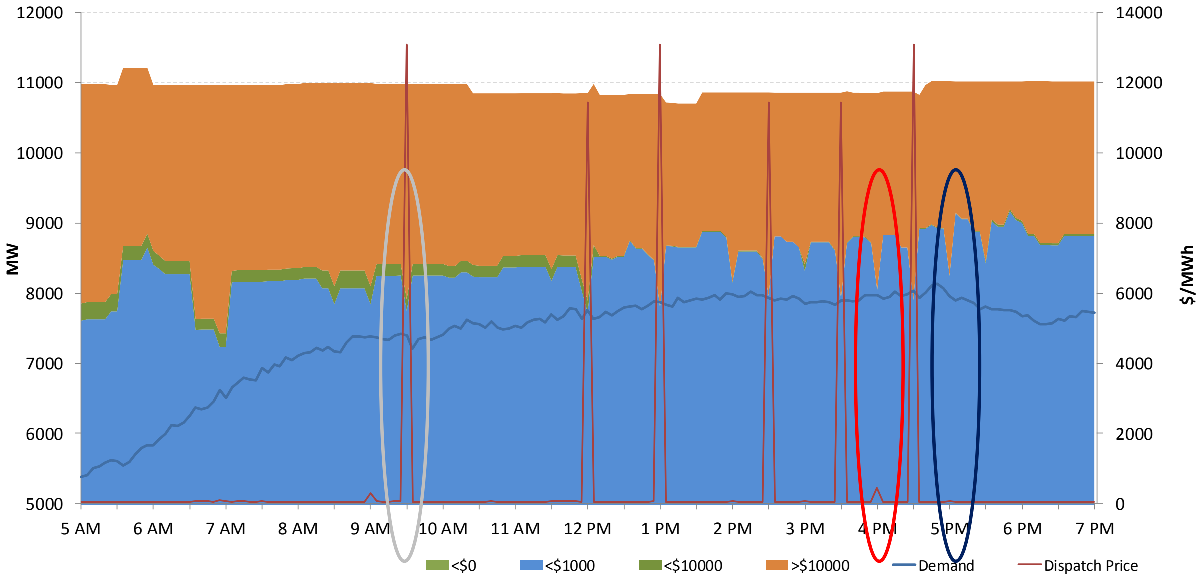


It is not unusual for this constraint to noticeably reduce the nominal capacity of QNI into Queensland. Our analysis, however, shows that this constraint bound slightly less frequently over 2013/14 summer period compared to the same time the previous year and during those periods of constraint the import limit into Queensland was slightly higher.

3. *Frequency of rebidding*

To provide an example of the repeated nature of the rebidding by CS energy, on 21 February the dispatch price exceeded $1000/MWh on six occasions. Spotlight Figure 6 shows the price of capacity offered into the market (in price bands) in Queensland as well as the dispatch price and total demand.

Spotlight Figure 6: Queensland closing offers, price and total demand on 21 February



This figure highlights that prior to mid-day there was around 150 MW priced between $1000/MWh and $10 000/MWh but from mid-day that capacity had been rebid into lower priced bands. The sawtooth shape of the blue area on the chart shows that capacity was repeatedly moved from less than $1000/MWh to greater than $10 000/MWh for short periods. While the spikes in the red dispatch price line show those that were successful at lifting the price it also shows that many attempts were unsuccessful.

For example:

- In the 9.00 am trading interval (inside the grey oval) gas turbines owned by Alinta and AGL started and rebid their capacity down from around $100/MWh to $0/MWh. Effective 8.55 am CS Energy rebid around 300 MW from around $50/MWh to greater than $12 000/MWh, successfully increasing the price as a number of other units, in the mid-price range were ramp up constrained.

- In the 4.00 pm trading interval (inside the red oval) the CS Energy rebidding was marginally successful as it lifted the price to around $300/MWh

- In the 5.00 pm trading interval (inside the blue oval) the rebidding by CS Energy failed to lift the price significantly.

This represents a small subset of events that occurred during the summer period but is typical of the behaviour that was repeated on many other days.

Ramp rates

Ramp rates determine how quickly a generator can change its output in a given time frame. If a generator rebids into high price bands and, as a result has its output reduced, then assuming other factors remain unchanged, another generator needs to increase its output to compensate. If there isn't enough generation available to ramp up to compensate then higher priced generation will need to be dispatched causing higher prices. Spotlight Table 2 shows the actual available ramp up and down rates in Queensland by participant over the summer period.

Spotlight Table 2: Queensland participants ramp rates

Participant	Average Ramp Rate up MW/minute	Average Ramp Rate Down MW/minute
AGL Energy	34	34
Alinta Energy	24	24
Arrow Energy	33	24
Callide Power Trading[9]	8	8
CS Energy	283	289
Ergon Energy	3	3
Millmerran Energy Trader	2	2
Origin Energy	51	49
QGC Sales	3	3
RTA Yarwun	0	0
Stanwell Corporation	71	60
Total	512	496
Summary by plant Type		
Peak	94	92
Base	95	102
Intermediate	323	302
Total	512	496

Spotlight Table 2 shows that the CS Energy portfolio has over half of the ramping capability in Queensland, a potentially significant factor in ensuring the success of its rebidding strategy. It also shows that ramping capability of the base load generators (those that are typically always on) in the State is quite limited. Most of the ramp rate capability comes from intermediate generation (those that are typically on during peak times and will respond to modest prices) and a majority of this is at CS Energy's Wivenhoe station which has ramp rates of 240 MW/min. In situations when CS Energy shifted large volumes of available generation into high price bands, the remaining available generators were often unable to respond adequately to avoid high prices being set.

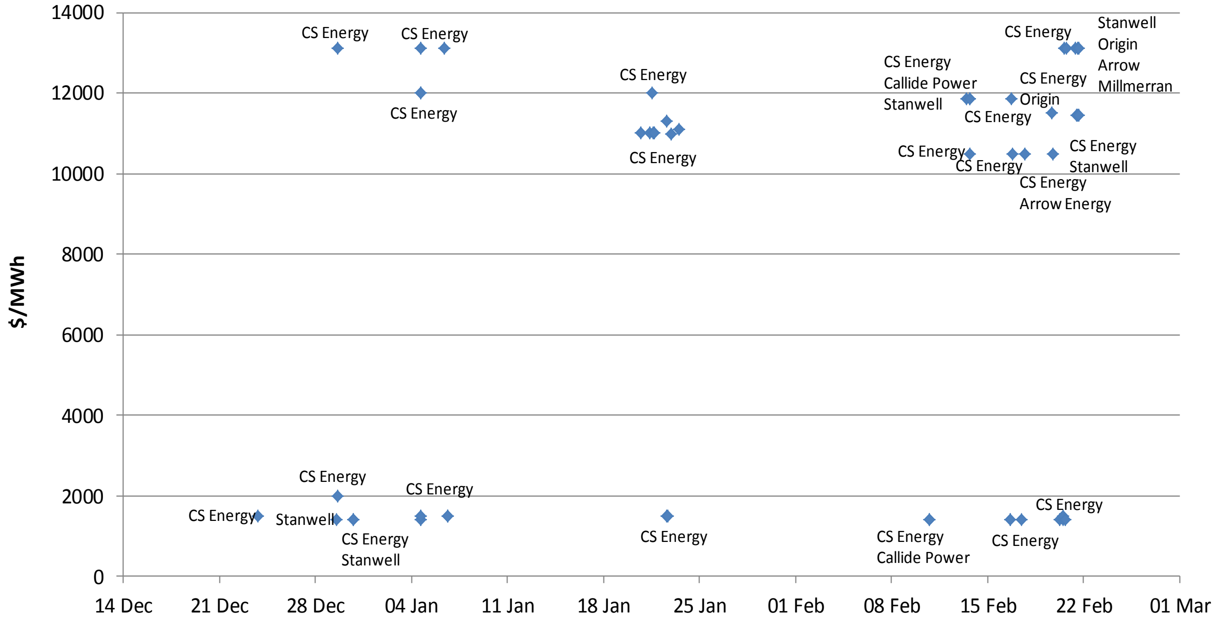
The CS Energy portfolio includes Gladstone and Wivenhoe, both of which have significant ramping capability. When CS Energy rebids the capacity of these generators up to high prices there is effectively less plant available to ramp up in response. When this occurs the slower to ramp generators are constrained and higher priced generators are dispatched.

During December, when CS Energy was the dominant participant rebidding operating capacity into high prices, other base and intermediate plant was ramped up to their limit to compensate. This situation changed over time and in February, when CS Energy and other participants with base and intermediate plant engaged in similar strategies. As a result there was even less low priced capacity that could be ramped up, leading to more frequent and higher prices.

[9] CS Energy and InterGen each have control of 50% of the output of Callide Power

Spotlight Figure 7 shows which participants rebid significant amounts of capacity into high prices for the 50 events being analysed.

Spotlight Figure 7: Dispatch price above $1000/MWh and major rebidding participant



This figure shows that during December and January the majority of the high price events were triggered by rebids from CS Energy. Their behaviour significantly changed the shape of the supply curve in the region and would have been evident to other participants. In response to these changing conditions, participants developed a range of different strategies including similar volume and price rebidding approaches. In February, rebidding capacity from low to high prices by other participants at or very close to the same time as CS Energy led to more frequent price spikes by exacerbating the paucity of capacity in the middle price ranges. The absence of other Queensland participants seems to indicate that while the new strategies of some participants were similar to those of CS Energy others chose different strategies to protect their positions or plant. Notably the rebidding in February did not result in as significant a change in the merit order as had been evident earlier in the summer and appears to have reduced the output adjustments and ramping that the rebidding would normally trigger.

The AER is closely reviewing the rebidding behaviour during this period to verify the rebid reasons and assessing the material conditions relied upon to support those rebids.

Spot market prices

Figure 1 shows the spot prices that occurred in each region during the week 23 February to 1 March 2014.

Figure 1: Spot price by region ($/MWh)

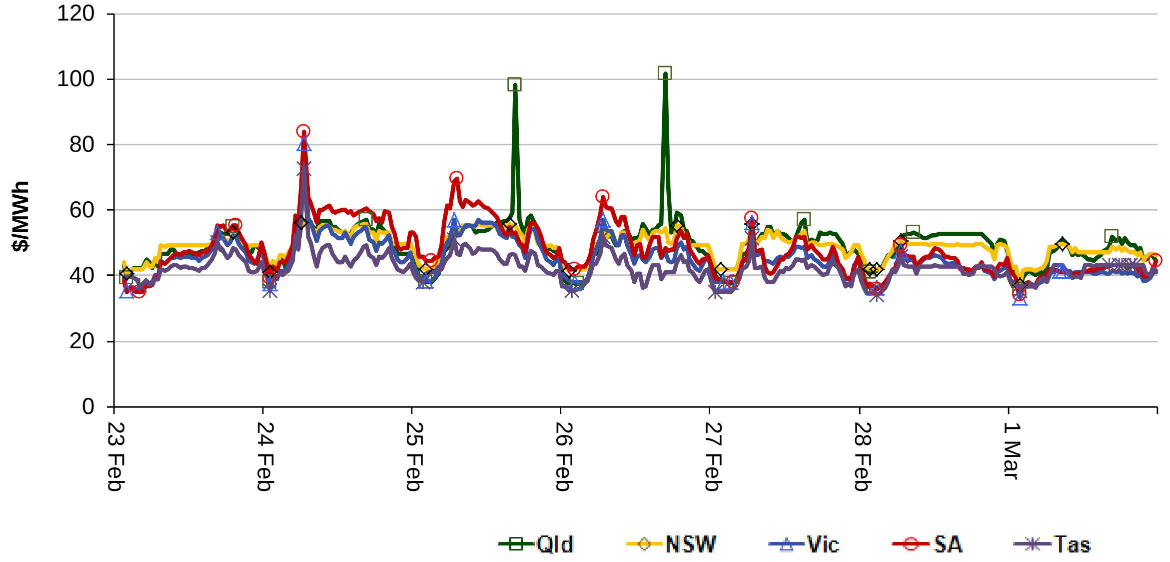


Figure 2 shows the volume weighted average (VWA) prices for the current week (with prices shown in Table 1) and the preceding 12 weeks, as well as the VWA price over the previous 3 financial years.

Figure 2: Volume weighted average spot price by region ($/MWh)

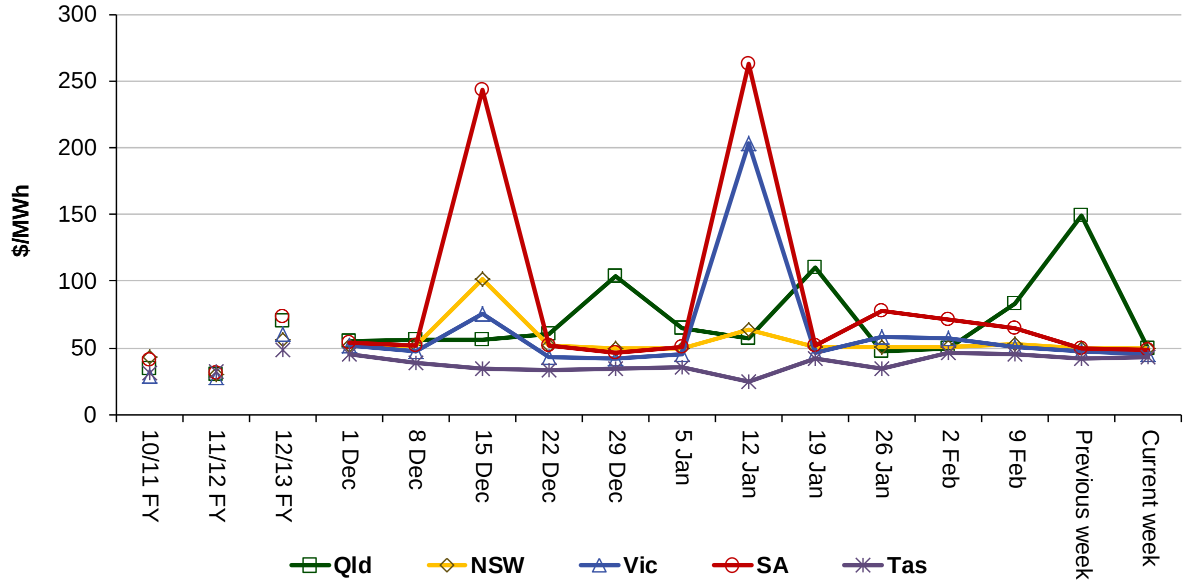


Table 1: Volume weighted average spot prices by region ($/MWh)

Region	Qld	NSW	Vic	SA	Tas
Current week	50	50	46	48	43
12-13 financial YTD	70	56	61	73	49
13-14 financial YTD	65	55	57	76	43

Longer-term statistics tracking average spot market prices are available on the AER website.

Spot market price forecast variations

The AER is required under the National Electricity Rules to determine whether there is a significant variation between the forecast spot price published by the Australian Energy Market Operator (AEMO) and the actual spot price and, if there is a variation, state why the AER considers the significant price variation occurred. It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions. A key focus is whether the actual price differs significantly from the forecast price either four or 12 hours ahead. These timeframes have been chosen as indicative of the time frames within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours).

There were 7 trading intervals throughout the week where actual prices varied significantly from forecasts. This compares to the weekly average in 2013 of 97 counts and the average in 2012 of 60. Reasons for the variations for this week are summarised in Table 2. Based on AER analysis, the table summarises (as a percentage) the number of times when the actual price differs significantly from the forecast price four or 12 hours ahead and the major reason for that variation. The reasons are classified as availability (which means that there is a change in the total quantity or price offered for generation), demand forecast inaccuracy, changes to network capability or as a combination of factors (when there is not one dominant reason). An instance where both four and 12 hour ahead forecasts differ significantly from the actual price will be counted as two variations.

Table 2: Reasons for variations between forecast and actual prices

	Availability	Demand	Network	Combination
% of total above forecast	8	0	0	25
% of total below forecast	0	67	0	0

Note: Due to rounding, the total may not be exactly 100 per cent

Generation and bidding patterns

The AER reviews generator bidding as part of its market monitoring to better understand the drivers behind price variations. Figure 3 to Figure 7 show, the total generation dispatched and the amounts of capacity offered within certain price bands for each 30 minute trading interval in each region.

Figure 3: Queensland generation and bidding patterns

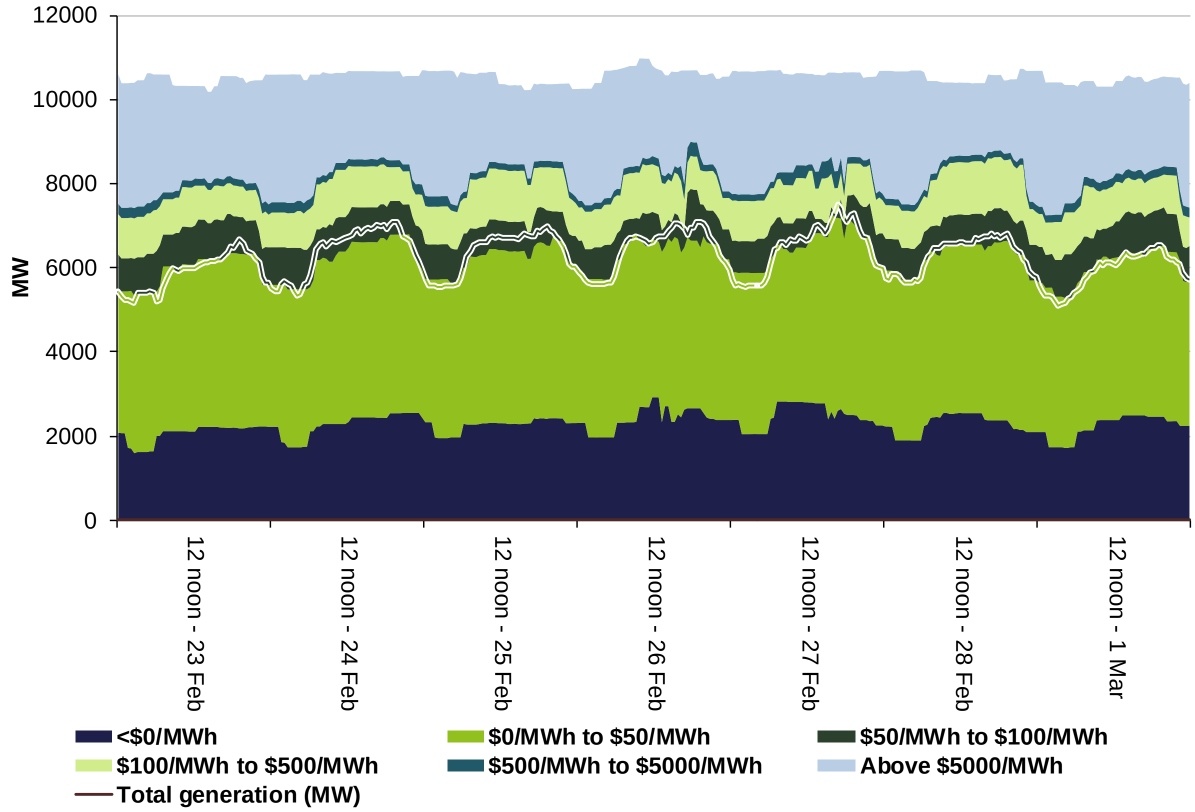


Figure 4: New South Wales generation and bidding patterns

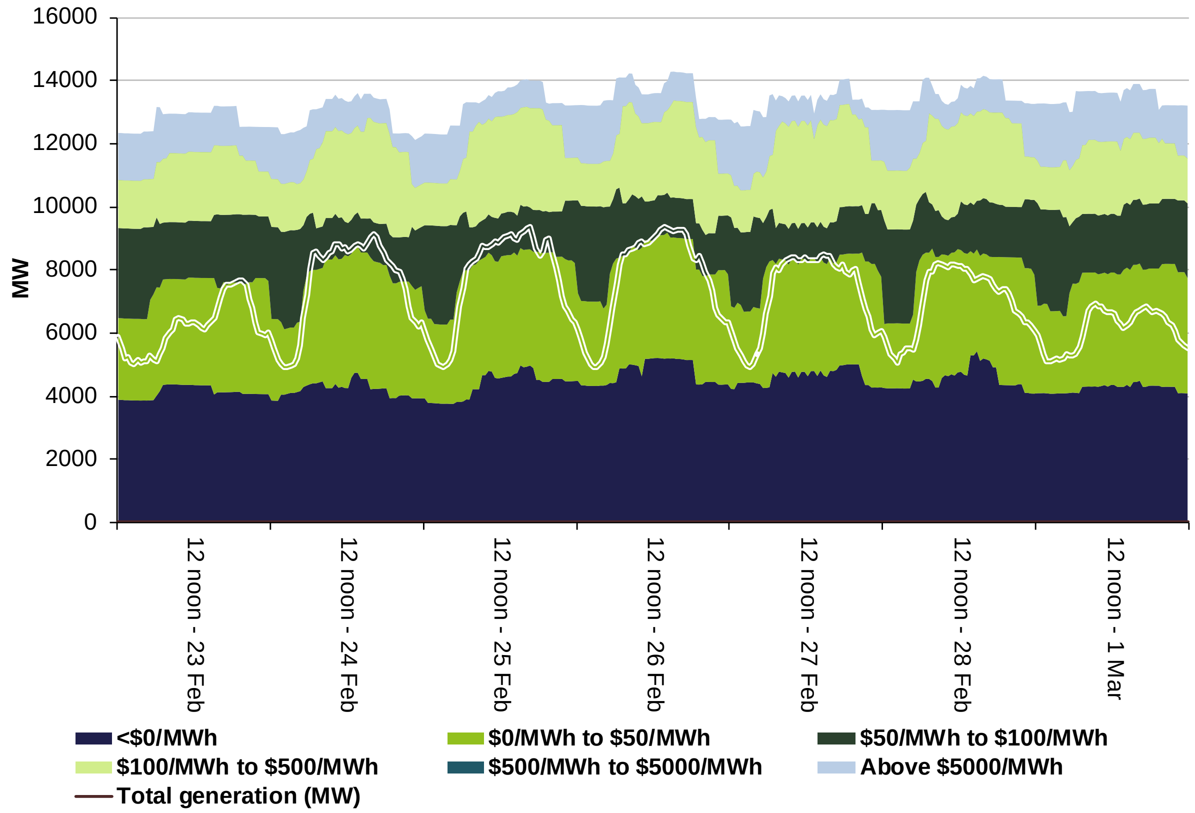


Figure 5: Victoria generation and bidding patterns

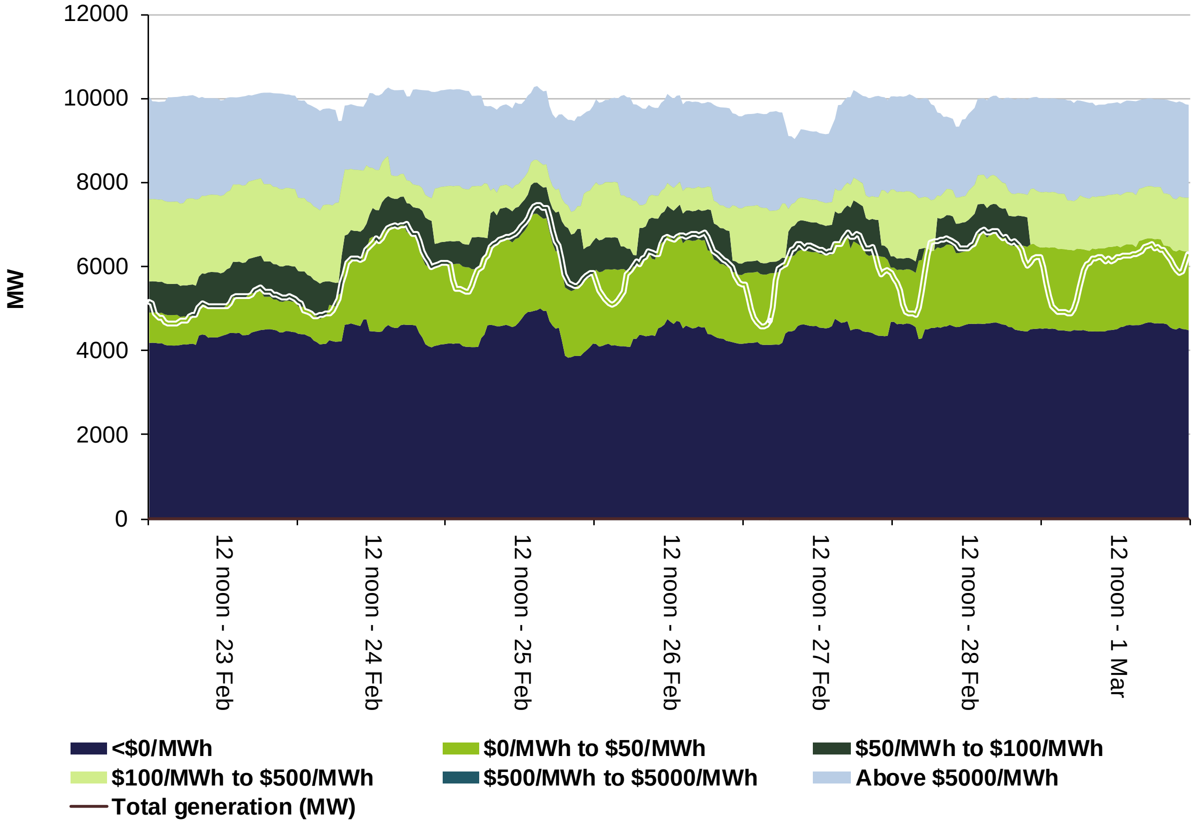


Figure 6: South Australia generation and bidding patterns

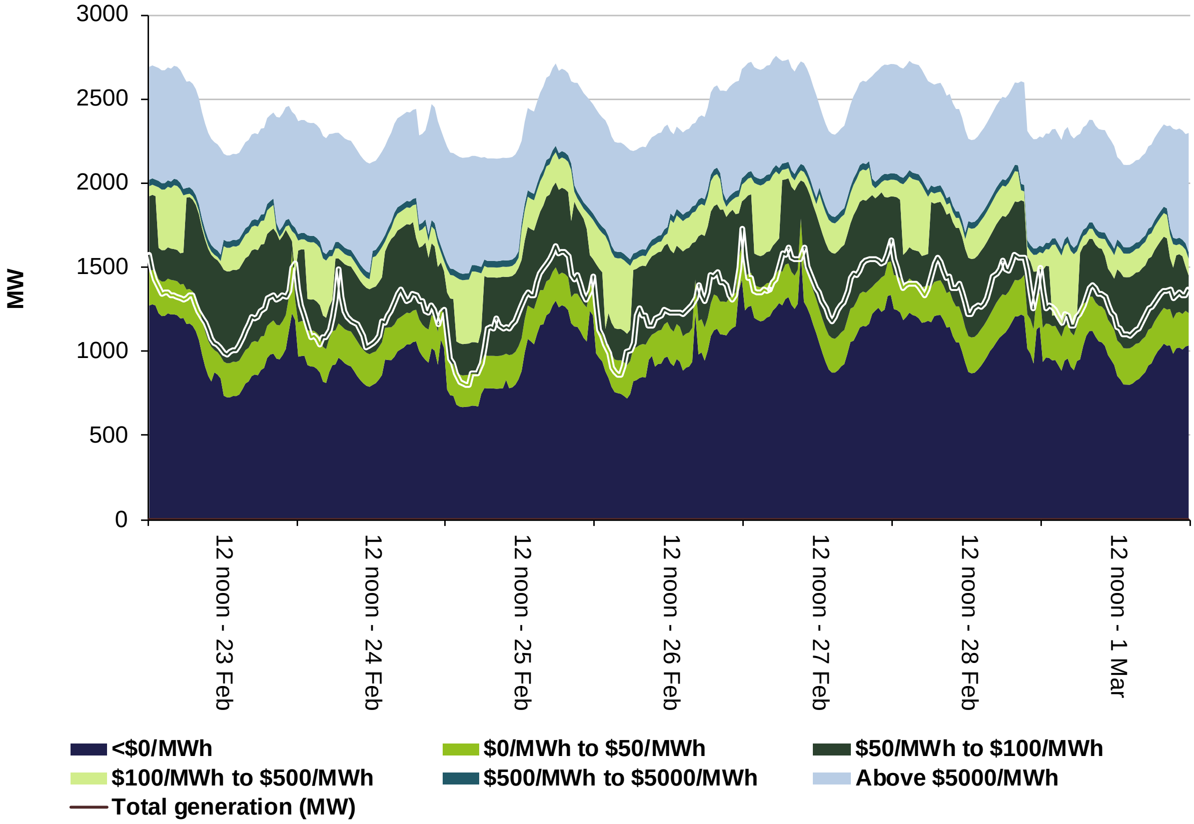
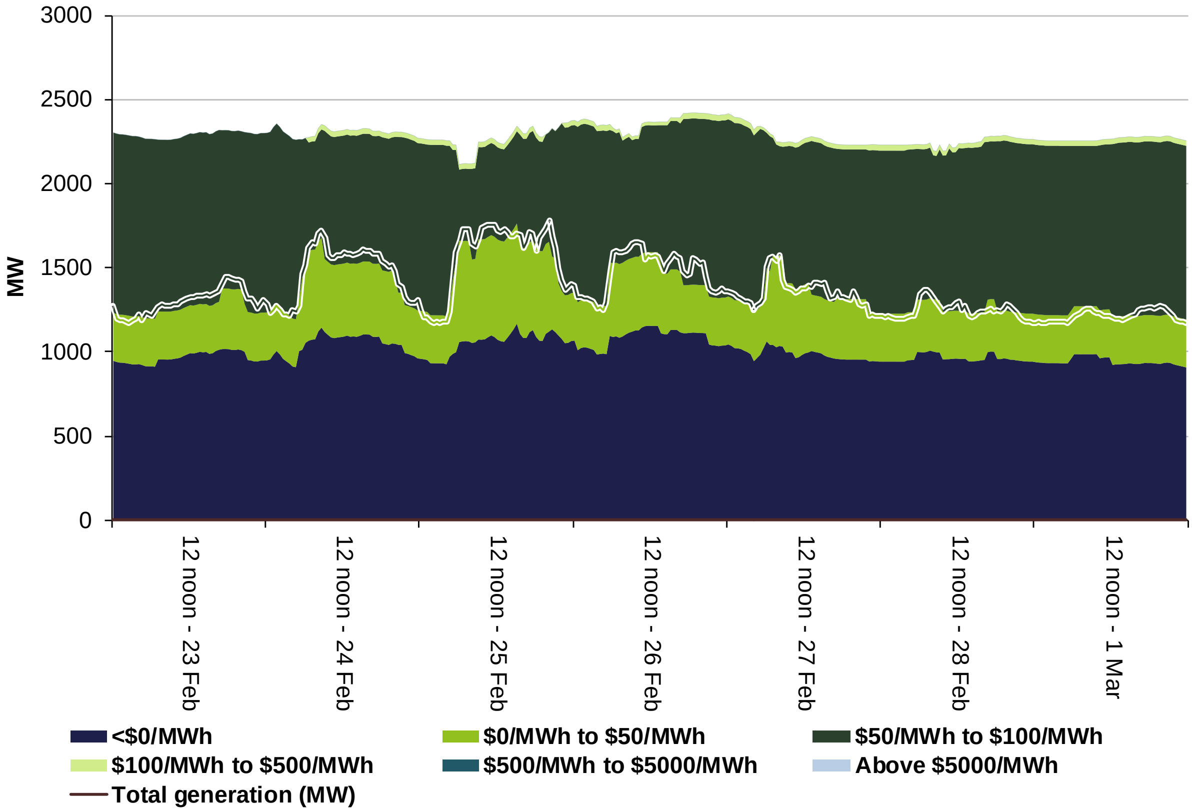


Figure 7: Tasmania generation and bidding patterns



Frequency control ancillary services markets

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within the frequency operating standards. Raise and lower regulation services are used to address small fluctuations in frequency, while raise and lower contingency services are used to address larger frequency deviations. There are six contingency services:

- *fast services*, which arrest a frequency deviation within the first 6 seconds of a contingent event (raise and lower 6 second)

- *slow services*, which stabilise frequency deviations within 60 seconds of the event (raise and lower 60 second)

- *delayed services*, which return the frequency to the normal operating band within 5 minutes (raise and lower 5 minute) at which time the five minute dispatch process will take effect.

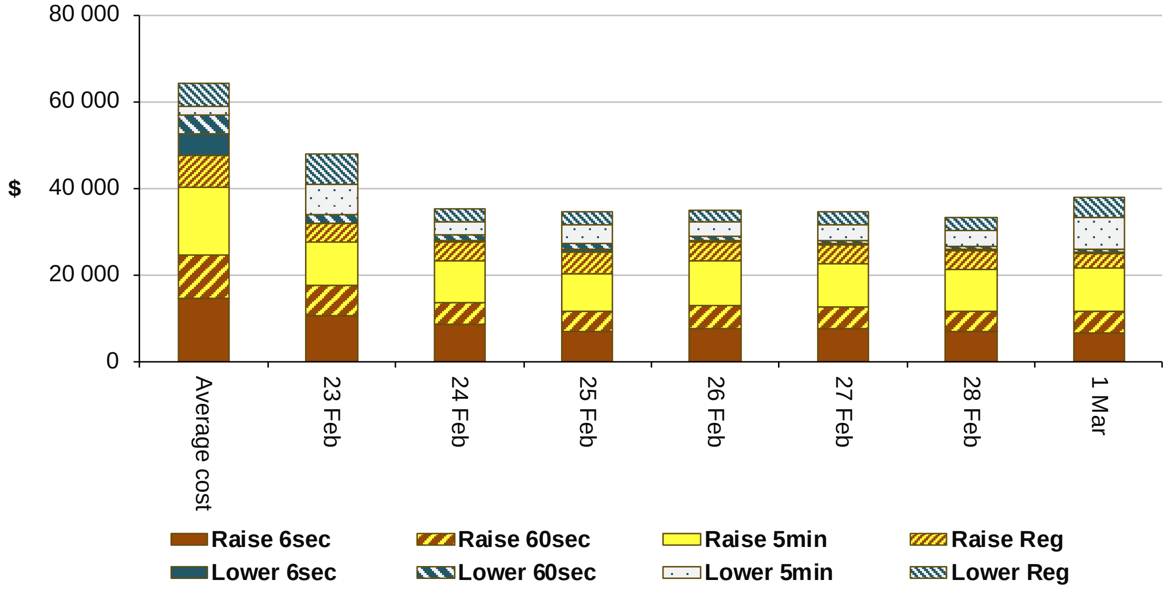
The Electricity Rules stipulate that generators pay for raise contingency services and customers pay for lower contingency services. Regulation services are paid for on a “causer pays” basis determined every four weeks by AEMO.

The total cost of FCAS on the mainland for the week was $235 500 or less than 1 per cent of energy turnover on the mainland.

The total cost of FCAS in Tasmania for the week was $22 000 or less than 1 per cent of energy turnover in Tasmania.

Figure 8 shows the daily breakdown of cost for each FCAS for the NEM, as well as the average cost since the beginning of the previous financial year.

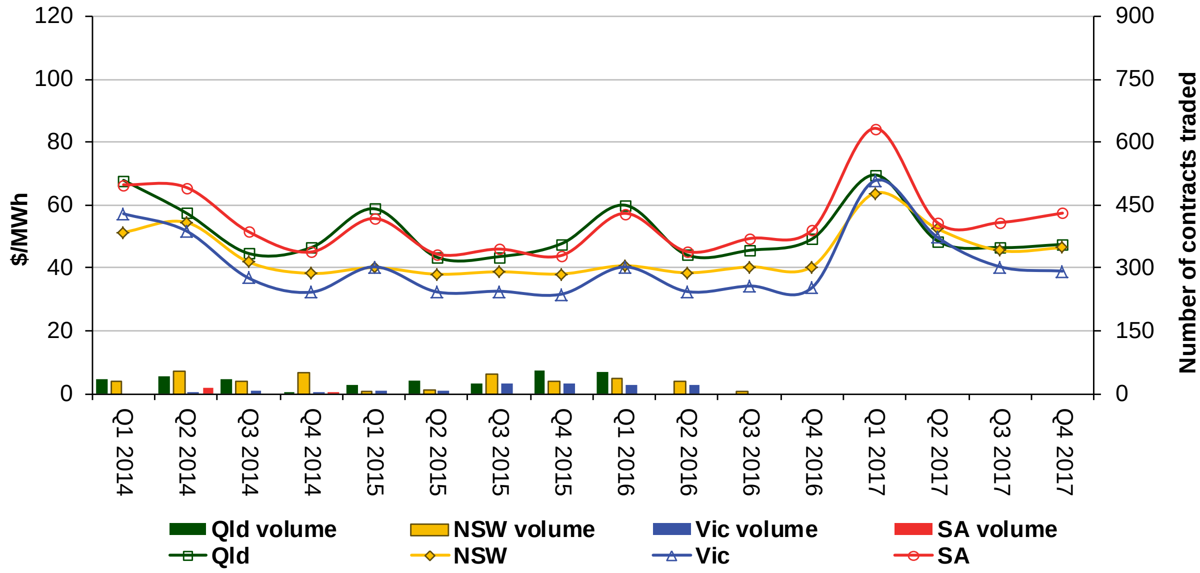
Figure 8: Daily frequency control ancillary service cost



Financial markets

Figure 9 shows for all mainland regions the prices for base contracts (and total traded quantities for the week) for each quarter for the next four financial years.

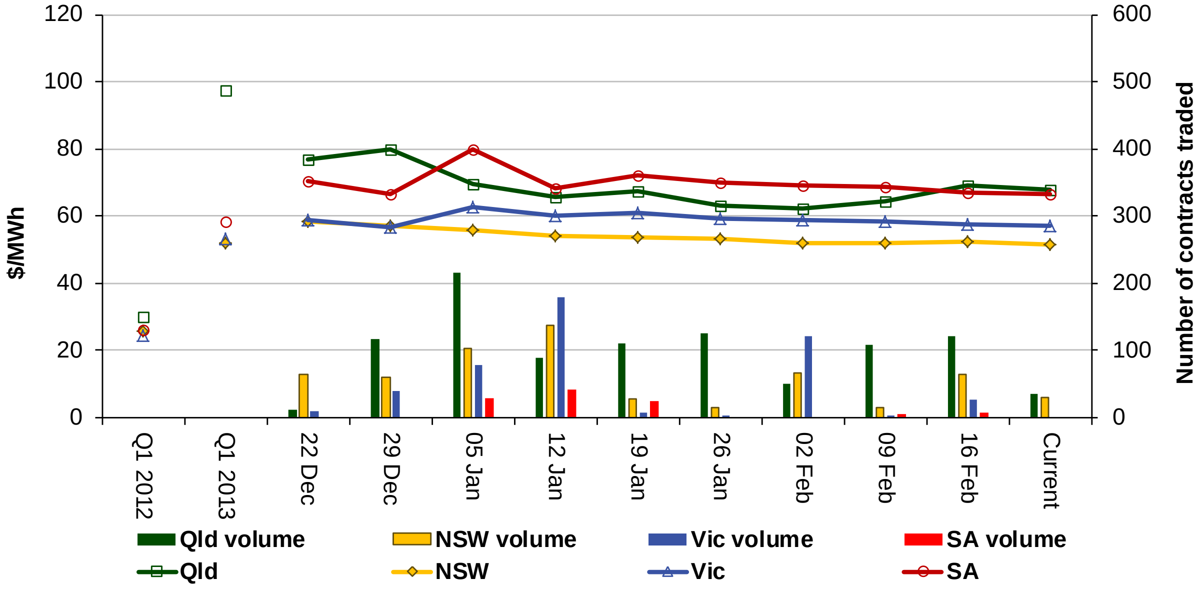
Figure 9: Quarterly base future prices Q1 2014 – Q4 2017



Source: ASXEnergy.com.au

Figure 10 shows how the price for each regional Quarter 1 2014 base contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2012 and quarter 1 2013 prices are also shown. The AER notes that data for South Australia is less reliable due to very low numbers of trades.

Figure 10: Price of Q1 2014 base contracts over the past 10 weeks (and the past 2 years)



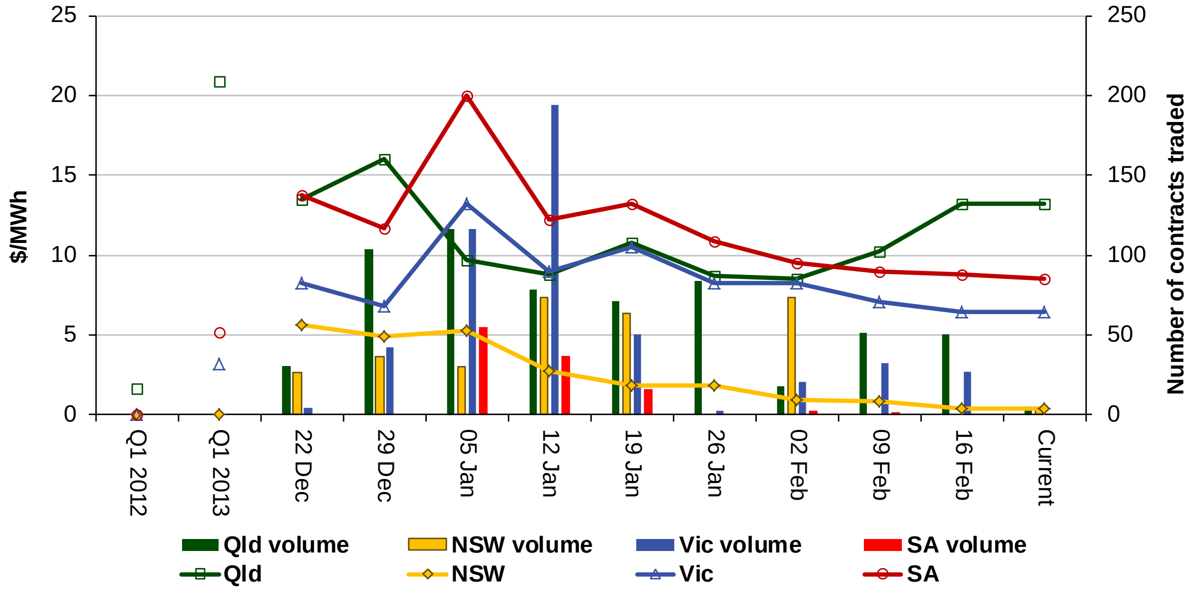
Note: Base contract prices are shown for each of the current week and the previous 9 weeks, with average prices shown for yearly periods 1 and 2 years prior to the current year

Source: ASXEnergy.com.au

Prices of other financial products (including longer-term price trends) are available in the Performance of the Energy Sector section of our website.

Figure 11 shows how the price for each regional Quarter 1 2014 cap contract has changed over the last 10 weeks (as well as the total number of trades each week). The closing quarter 1 2012 and quarter 1 2013 prices are also shown.

Figure 11: Price of Q1 2014 cap contracts over the past 10 weeks (and the past 2 years)



Source: ASXEnergy.com.au

Australian Energy Regulator

March 2014