

Market analysis



3 – 9 SEPTEMBER 2006

Spot prices for the week averaged between \$22/MWh in Queensland and \$37/MWh in Tasmania.

Turnover in the energy market was \$115 million. The total cost of ancillary services for the week was \$300 000, or 0.3 per cent of energy market turnover.

Significant variations between actual prices and those forecast 4 and 12 hours ahead occurred in 51, or 15 per cent of all trading intervals. Demand forecasts produced 4 and 12 hours ahead varied from actual by more than 5 per cent in 16 per cent of all trading intervals across the market. These variations were most frequent in South Australia, occurring in almost a third of all trading intervals.

Energy prices

Figure 1 sets out the national demand and spot prices in each region for each trading interval. Figure 2 compares the volume weighted average price with the averages for the previous week, the same quarter last year and for the previous financial year.

Figure 1: national demand and spot prices

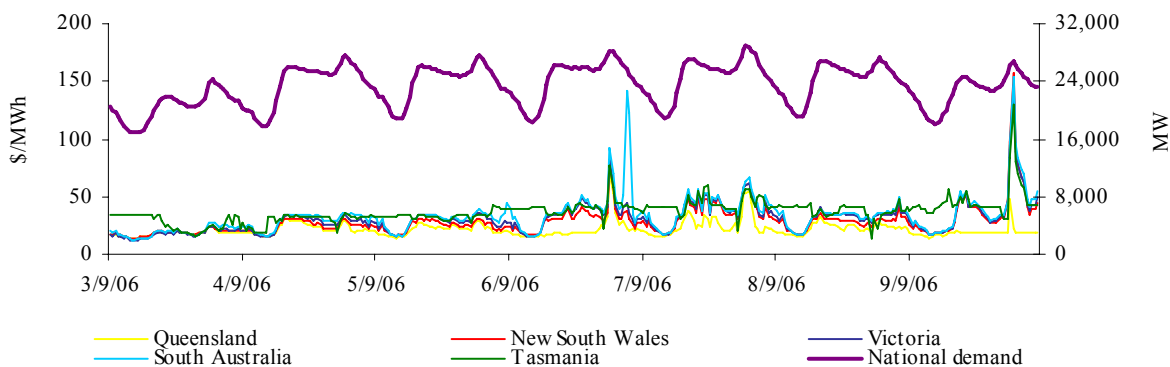


Figure 2: volume weighted average spot price for energy market (\$/MWh)

	QLD	NSW	VIC	SA	TAS
Last week	22	30	32	35	37
Previous week	24	28	31	33	35
Same quarter last year	22	29	30	34	100
Financial year 2005 - 06	31	43	36	44	59
% change from previous week*	▼8%	▲6%	▲3%	▲5%	▲7%
% change from same quarter last year**	▲1%	▲4%	▲6%	▲3%	▼63%

*The percentage change between last week's average spot price and the average price for the previous week.

**The percentage change between last week's average spot price and the average price for the same quarter last year.

Figures 3 to 7 show the weekly correlation between spot price and demand.

Figure 3: Queensland

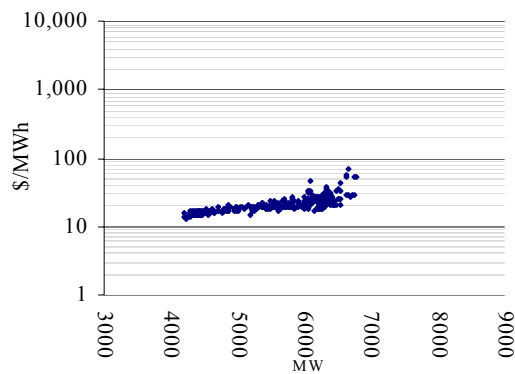


Figure 4: New South Wales

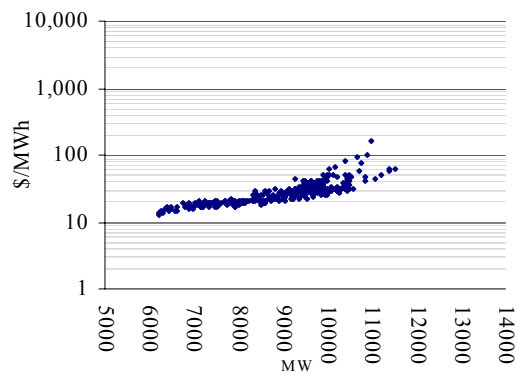


Figure 5: Victoria

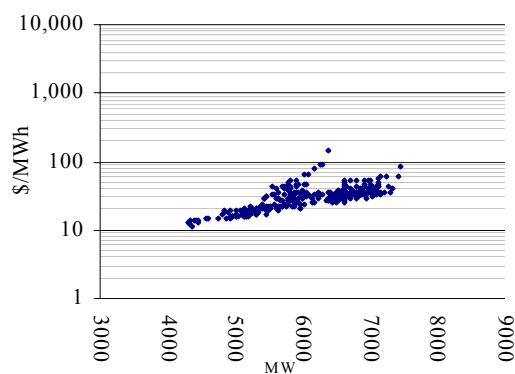


Figure 6: South Australia

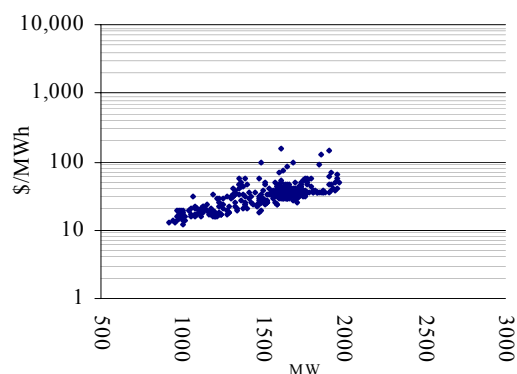
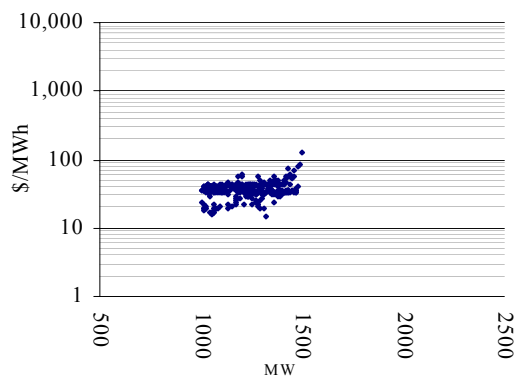


Figure 7: Tasmania



The maximum spot price in Queensland was \$70/MWh. This occurred at 6.30 pm on Wednesday. Elsewhere, maximum spot prices for the week ranged from \$131/MWh in Tasmania to \$158/MWh in New South Wales, all occurring at 7 pm on Saturday. Figure 8 compares the weekly price volatility index with the averages for the previous week and the same quarter last year.

Figure 8: volatility index during peak periods

	QLD	NSW	VIC	SA	TAS
Last week	0.46	0.50	0.45	0.49	0.35
Previous week	0.61	0.39	0.42	0.37	0.24
Same quarter last year	0.64	0.86	0.86	0.83	0.81

A definition of the price volatility index is available on the AER website.
<http://www.aer.gov.au/content/index.phtml/tag/MarketSnapshotLongTermAnalysis>

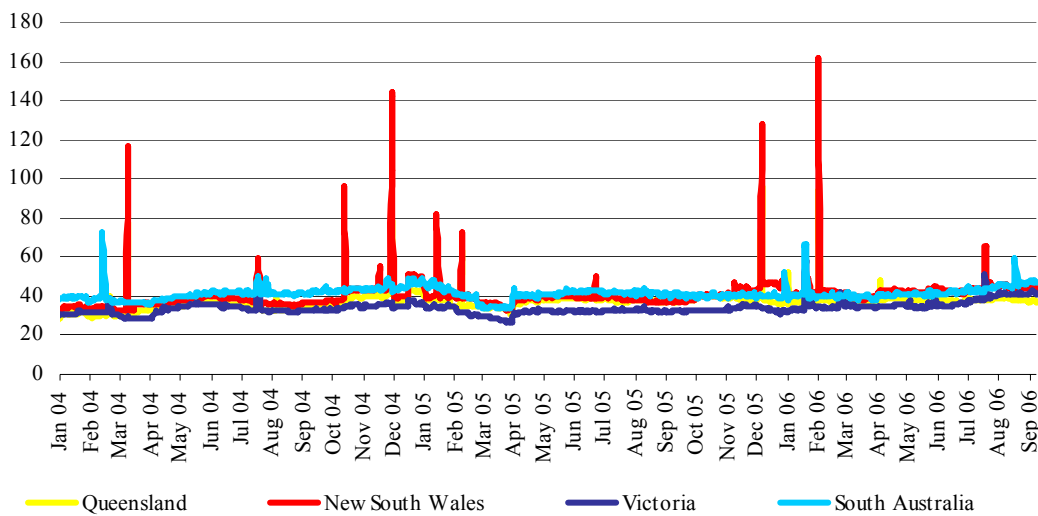
Figure 9 sets out the d-cyphaTrade wholesale electricity price index (WEPI)* for each region throughout the week excluding Tasmania. Figure 10 sets out the WEPI since 1 January 2004.

Figure 9: d-cyphaTrade WEPI for the week

	Monday	Tuesday	Wednesday	Thursday	Friday
Queensland	38.23	37.96	37.54	37.43	37.19
New South Wales	44.27	44.66	44.19	44.86	43.83
Victoria	42.76	41.96	41.92	41.67	41.25
South Australia	48.10	47.23	46.87	48.27	46.83

* A definition of the wholesale electricity price index is available on the d-cyphaTrade website
http://www.d-cyphatrade.com.au/products/wholesale_electricity_price_i

Figure 10: d-cyphaTrade WEPI



Reserve

There was no low reserve conditions forecast.

Figures 11 to 15: spot price, net import and limit at time of weekly maximum demand

Figure 11: Queensland

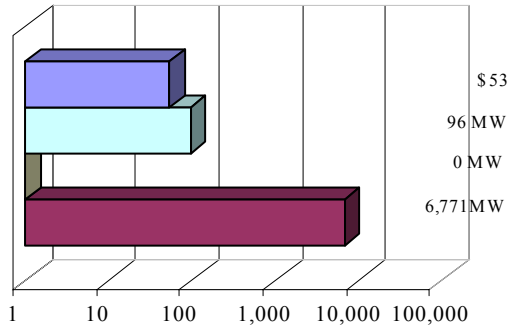


Figure 12: New South Wales

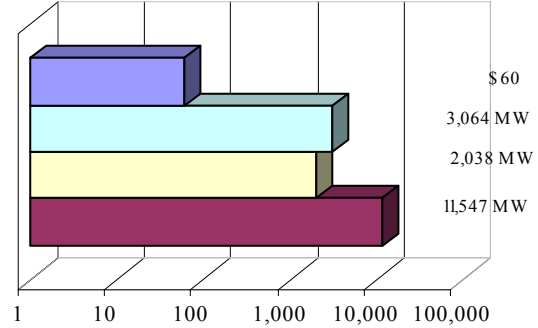


Figure 13: Victoria

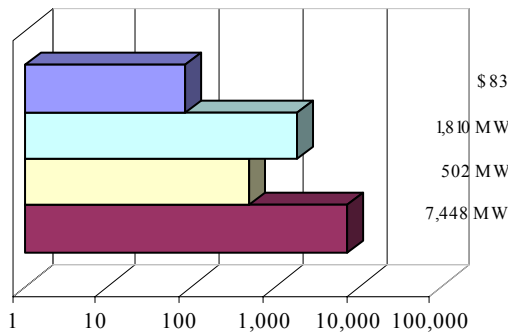


Figure 14: South Australia

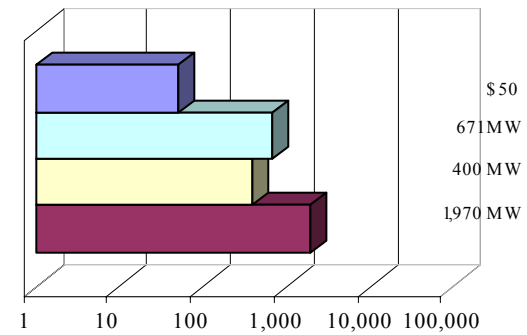
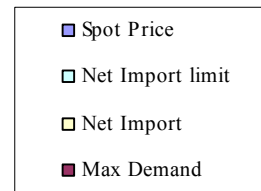
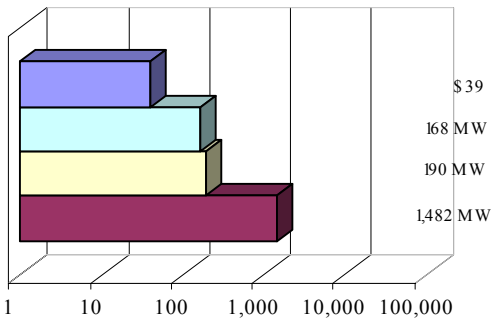


Figure 15: Tasmania



Price variations

There were 51 trading intervals where actual prices significantly varied from forecasts made 4 and 12 hours ahead of dispatch. Figures 16 to 20 show the difference in actual and forecast price versus the difference in actual and forecast demand. The figures highlight the relationship between price variation and demand forecast error. The information is presented in terms of the percentage difference from actual. Price differences beyond 100 per cent have been capped.

Figure 16: Queensland

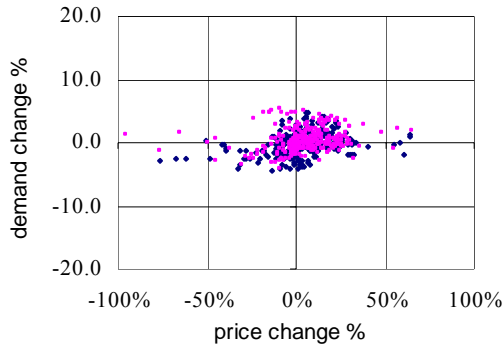


Figure 17: New South Wales

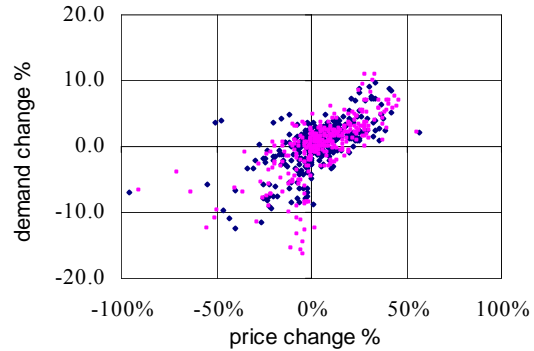


Figure 18: Victoria



Figure 19: South Australia

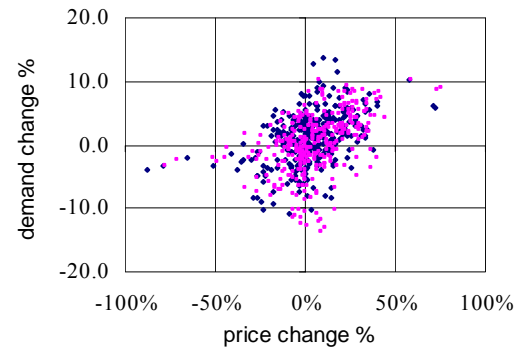


Figure 20: Tasmania

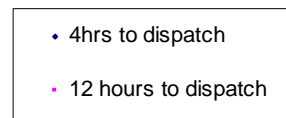
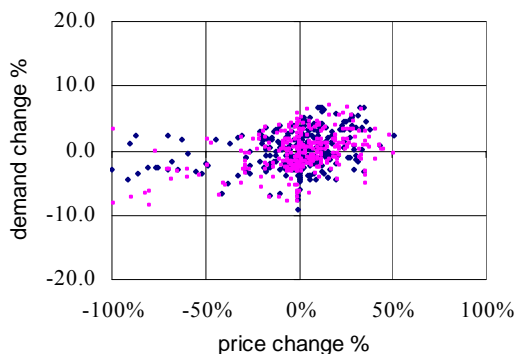
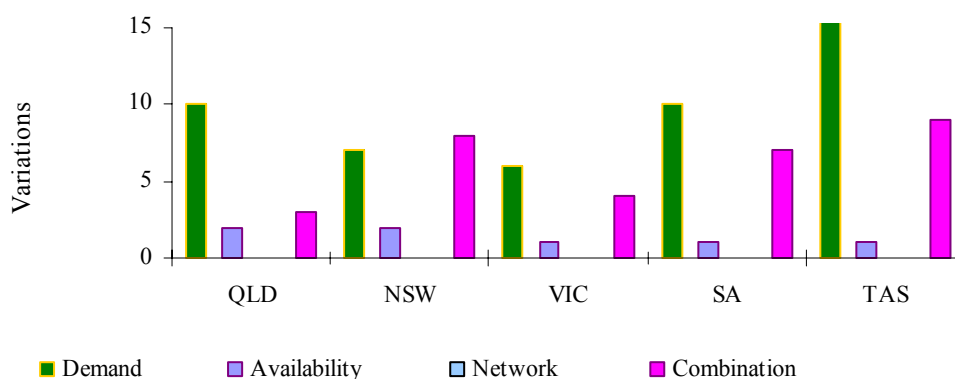


Figure 21 summarises the number and most probable reason for variations between forecast and actual prices.

Figure 21: reasons for variations between forecast and actual prices



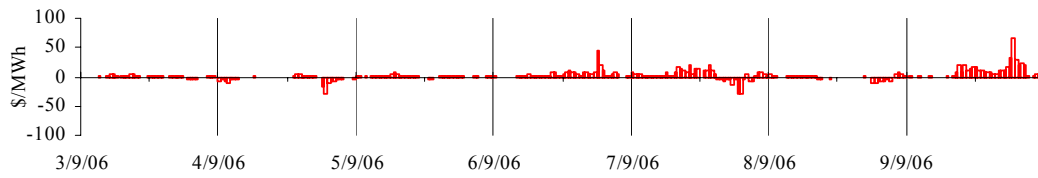
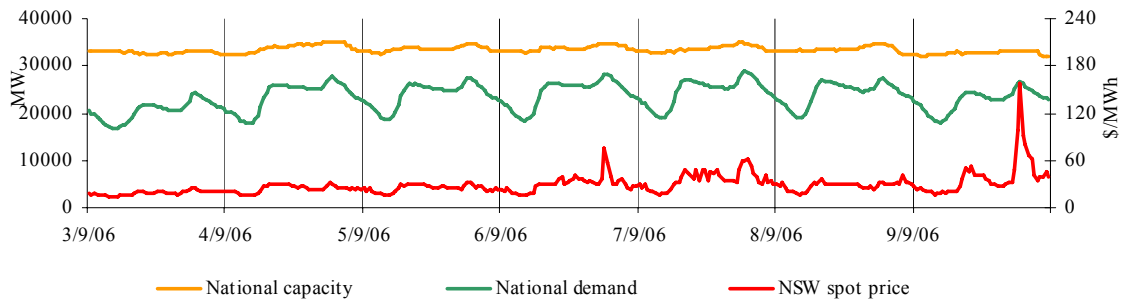
Price and demand

Figures 22 – 56 set out details of spot prices and demand on a national and regional basis. They include the actual spot price, actual demand and variation from forecasts made 4 and 12 hours ahead of dispatch.

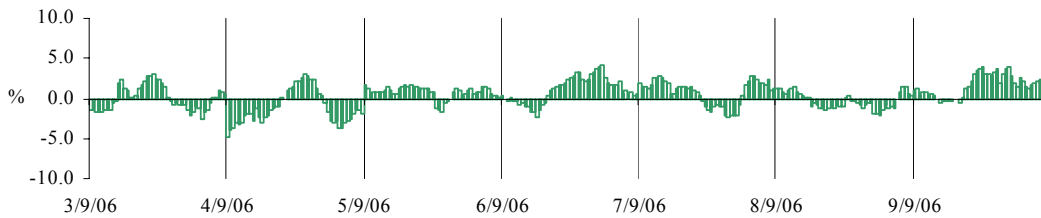
The regions within the national market are regularly aligned, with conditions in one region reflected across all others. The national market outcomes section highlights pricing events that occurred when spot prices were generally aligned across all regions of the national electricity market – the New South Wales spot price has been used to represent a pseudo national price under these conditions.

On a regional basis the differences between the maximum temperature and the temperature forecast at around 6.00 pm the day before are also included. In each section, the occurrences of all prices for the week greater than three times the average have been presented. The price forecast is compared to the demand and availability forecasts made 4 and 12 hours ahead, with significant changes to these forecasts explained.

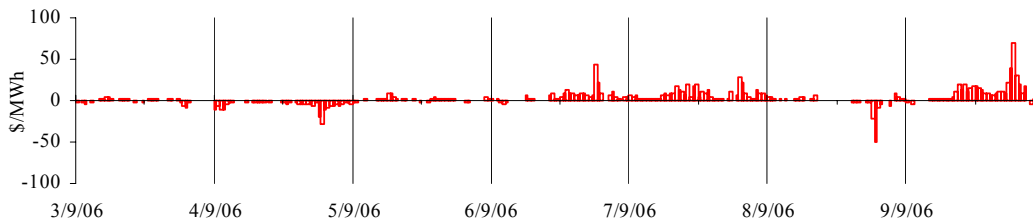
Figures 22-26: National market outcomes



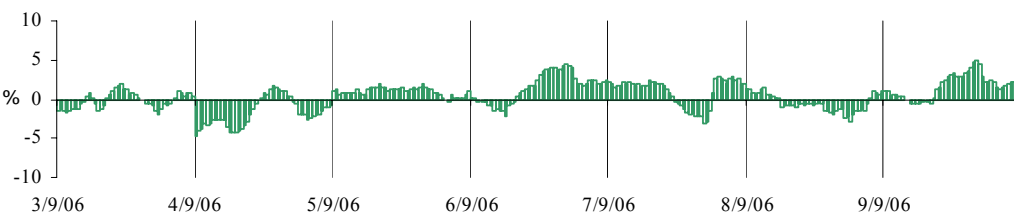
□ NSW price difference (actual - forecast) - 4hrs



□ National Demand difference (actual - forecast) - 4hrs



□ NSW price difference (actual - forecast) - 12 hrs



□ National Demand difference (actual - forecast) - 12hrs

National market outcomes

There were three occasions where spot prices were generally aligned nationally and the New South Wales price¹ was greater than three times the New South Wales weekly average price of \$30/MWh.

Saturday, 9 September

6:30 pm	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	97.29	64.39	58.20
Demand (MW)	26262	25887	25694
Available capacity (MW)	33259	33642	33629
7:00 pm	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	157.94	90.85	89.18
Demand (MW)	26668	25989	25998
Available capacity (MW)	33304	33644	33606
7:30 pm	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	92.24	62.24	60.82
Demand (MW)	26177	25613	25624
Available capacity (MW)	33306	33636	33605

Conditions at the time saw national demand up to 680 MW higher than forecast four hours ahead.

At 4.34 pm Macquarie Generation reduced the capacity of Liddell unit four by 235 MW, 180 MW of which was priced at less than \$10/MWh. The rebid reason given was “16:34 Feed pump limit.” At the same time, Macquarie Generation rebid 160 MW of capacity at Bayswater from prices above \$9300/MWh to below \$15/MWh. The rebid reason given was “16:30 Adjustment due to LD4”.

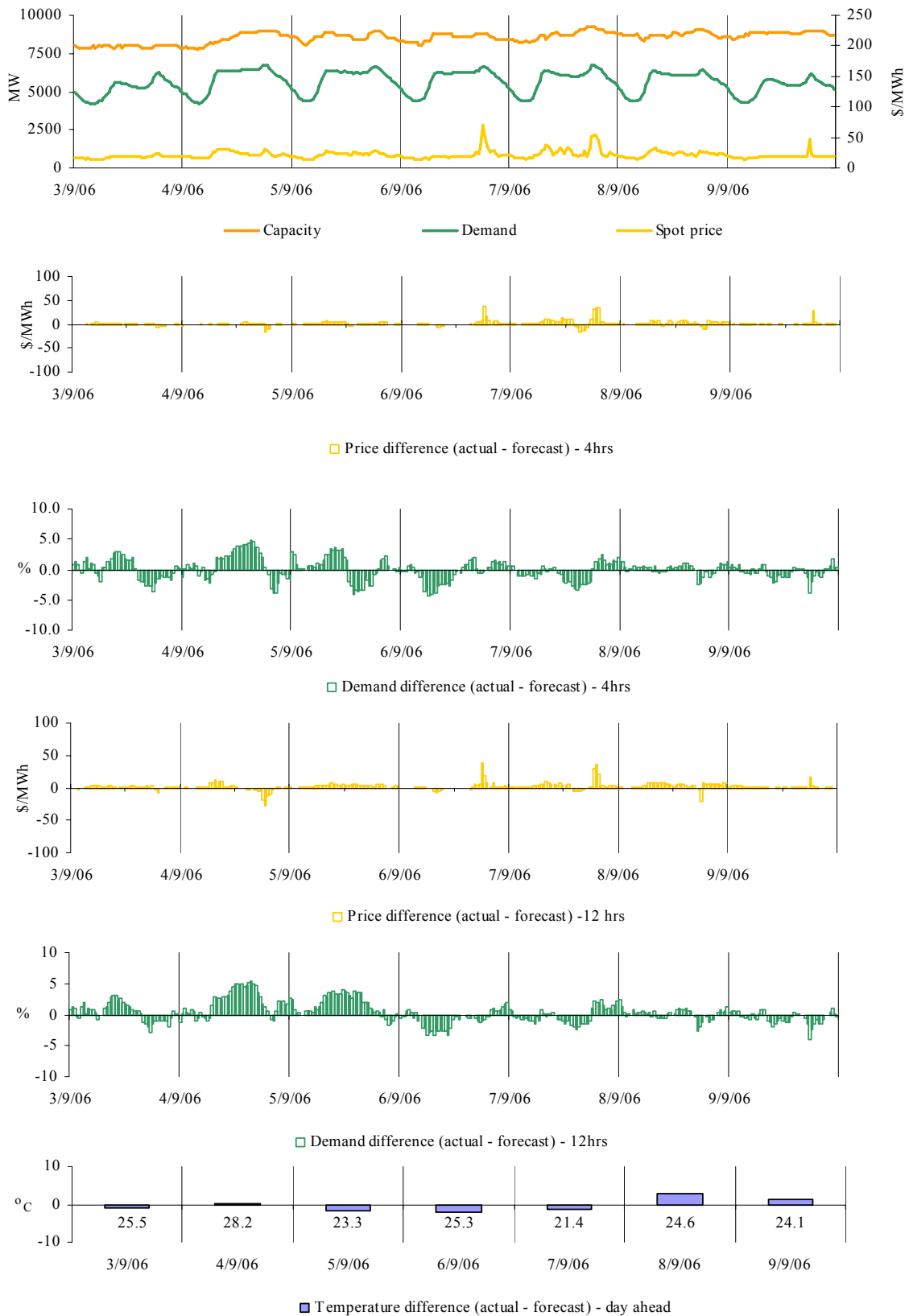
At 5.52 pm Macquarie Generation rebid 600 MW of capacity at Bayswater from prices below \$100/MWh to above \$9000/MWh. The rebid reason given was “1750 Load expected to vary from forecast”.

At 6.07 pm AGL rebid 160 MW of capacity at Somerton from prices above \$9000/MWh to zero. The rebid reason given was “1756N Predispatch-forecast price change::higher”.

There was no other significant rebidding.

¹ The New South Wales spot price has been used to represent a pseudo national price under these conditions.

Figures 27-32: Queensland actual spot price, demand and forecast differences



There was one occasion where the spot price in Queensland was greater than three times the weekly average price of \$22/MWh.

Wednesday, 6 September

6:30 pm	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	69.74	31.06	31.59
Demand (MW)	6653	6681	6719
Available capacity (MW)	8788	8767	8768

Conditions at the time saw demand and available capacity in Queensland close to forecast. Prices were higher than forecast and aligned across the market with national demand 700 MW higher than forecast four hours ahead.

Flows south across the Queensland to New South Wales interconnector were around 150 MW higher than forecast.

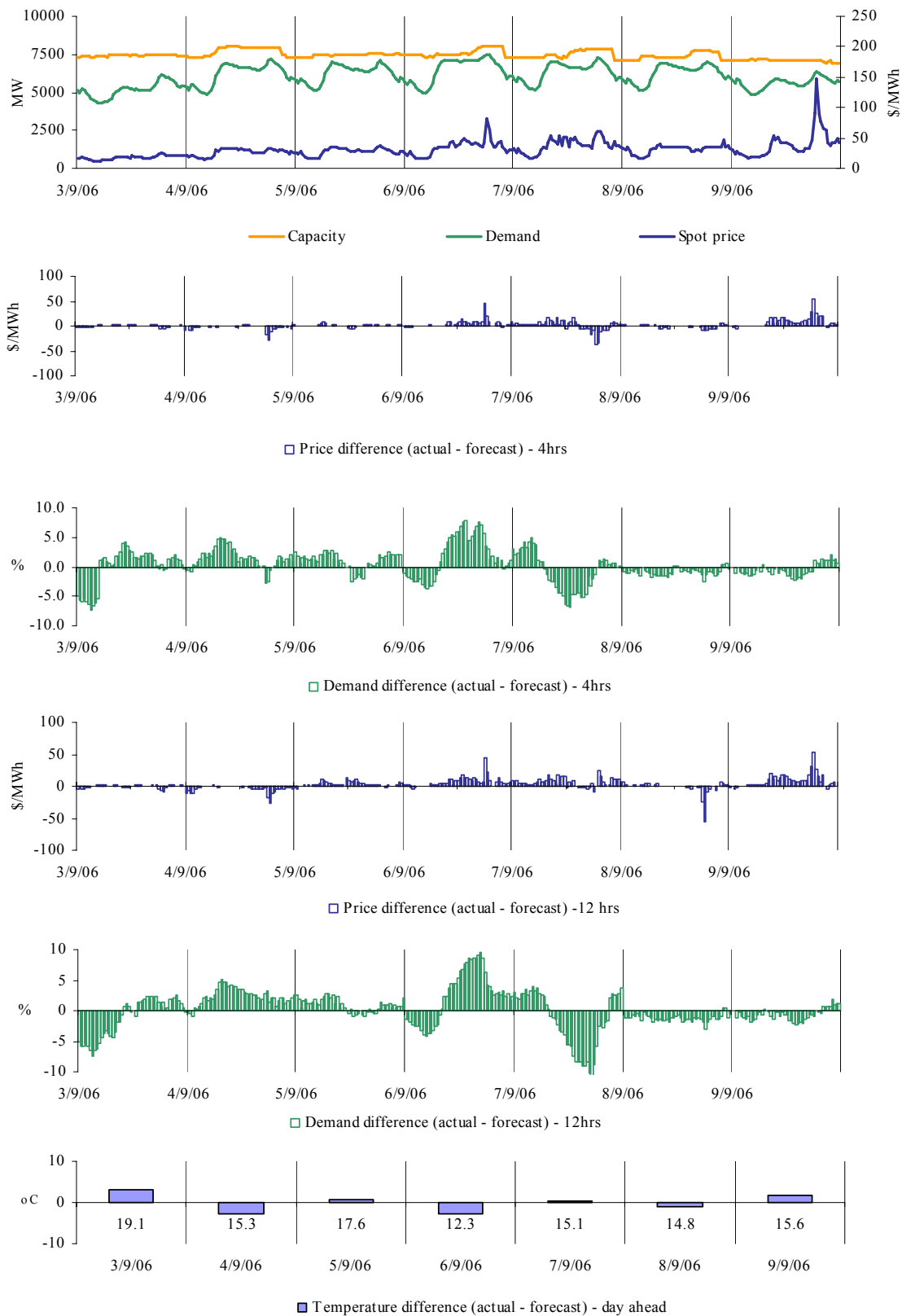
There was no significant rebidding.

Figures 33-38 New South Wales actual spot price, demand and forecast differences



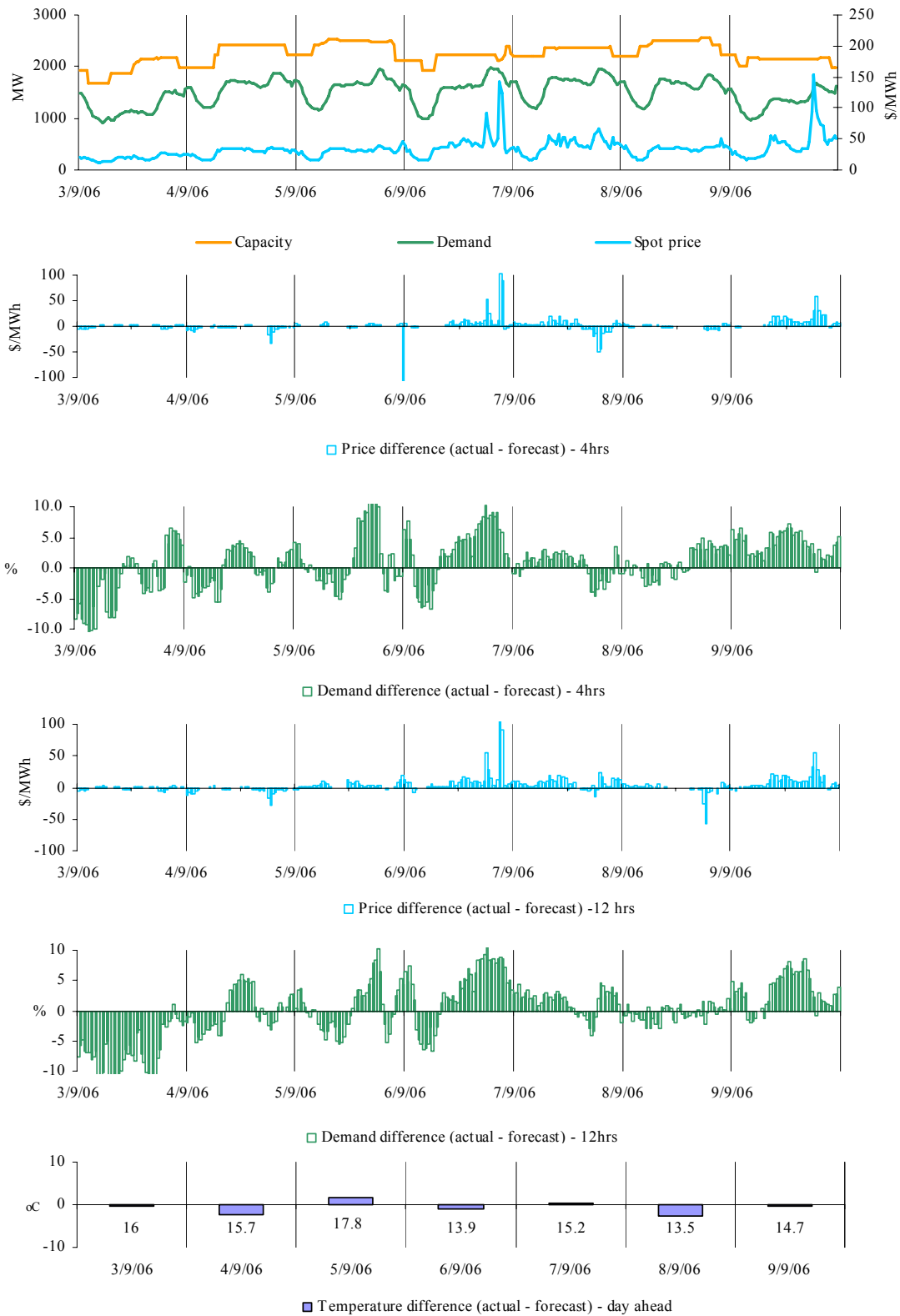
There were three occasions where the spot price in New South Wales was greater than three times the weekly average price of \$30/MWh. At the time, prices were aligned across the market. The circumstances of these events are detailed under the national market outcomes section.

Figures 39-44: Victoria actual spot price, demand and forecast differences



There was one occasion where the spot price in Victoria was greater than three times the weekly average price of \$32/MWh. At the time, prices were aligned across the market. The circumstances of this event are detailed under the national market outcomes section.

Figures 45-50: South Australia actual spot price, demand and forecast differences



There were three occasions where the spot price in South Australia was greater than three times the weekly average price of \$35/MWh. One of these occurred when prices were generally aligned across all regions and is detailed in the national market outcomes section. The remaining two occasions are presented below.

Wednesday, 6 September

9:30 pm	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	142.25	40.65	34.00
Demand (MW)	1911	1792	1740
Available capacity (MW)	2131	2176	2391
10:00 pm	Actual	4 hr forecast	12 hr forecast
Price (\$/MWh)	123.33	34.00	33.27
Demand (MW)	1859	1751	1698
Available capacity (MW)	2146	2236	2391

Conditions at the time saw demand in South Australia up to 120 MW higher than forecast four hours ahead. Flows across MurrayLink were at the limit of 220 MW and around 110 MW higher than that forecast. The Heywood interconnector was as forecast at its nominal limit of 460 MW.

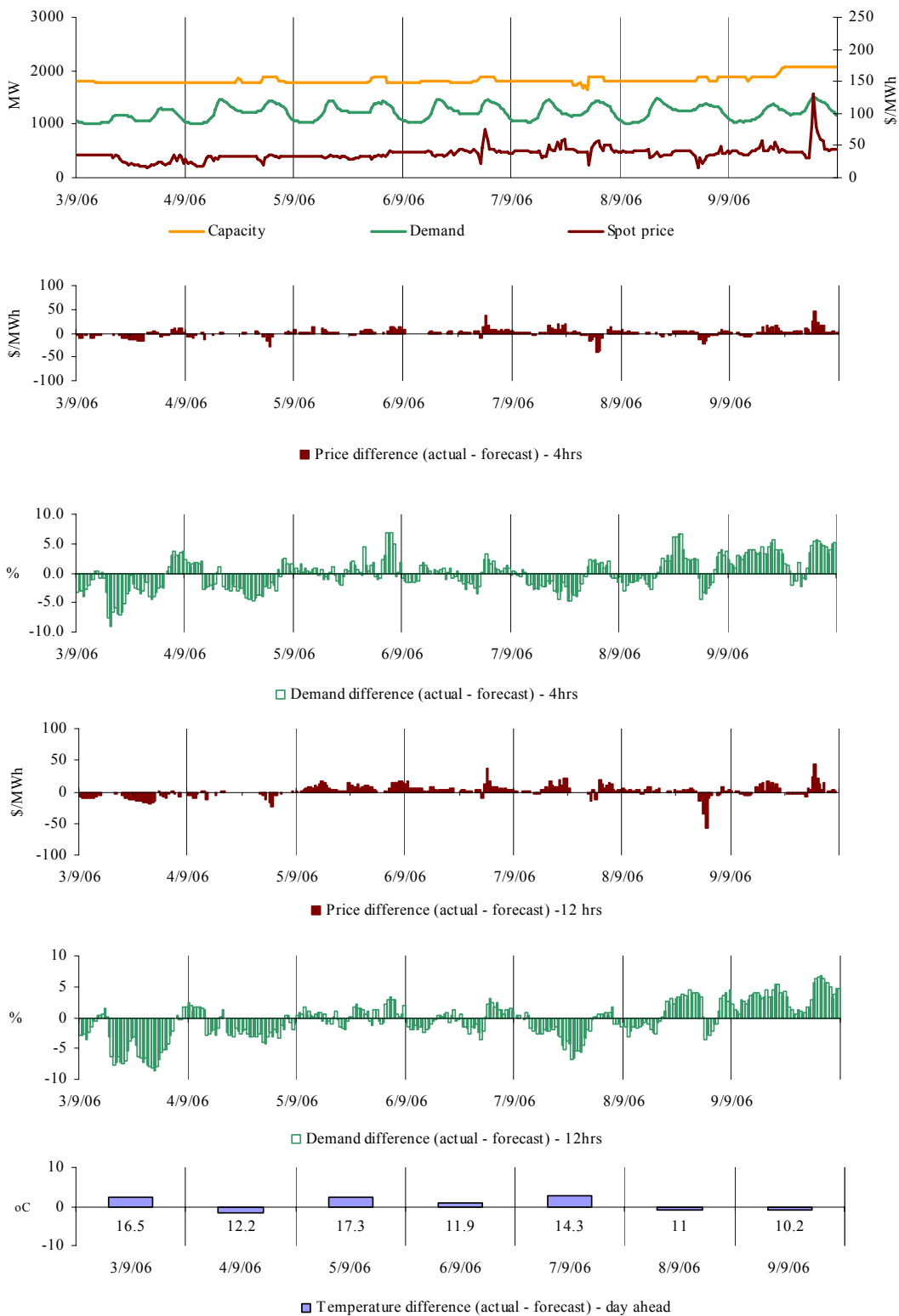
Delays in the return to service of unit one at Northern Power Station saw a reduction in available capacity throughout the evening. All of this capacity was priced below \$15/MWh. The rebid reasons given included “Delay in RTS NPS”.

International Power’s Pelican Point power stations had scheduled a 90 MW reduction in output during the 9.30 pm trading interval. This change was forecast to occur over the half hour. Pelican Point reduced output over two dispatch intervals. As a result, the 5-minute price increased slightly at the beginning of the trading interval with an increase in flows into South Australia across MurrayLink.

At 9.07 pm, TRU Energy rebid 280 MW of capacity at Torrens Island from prices of less than \$40/MWh to above \$145/MWh. The rebid reason given was “Market conditions – Gen response to IC conditions”.

There was no other significant rebidding.

Figures 51-56: Tasmania actual spot price, demand and forecast differences



There was one occasion where the spot price in Tasmania was greater than three times the weekly average price of \$37/MWh. At the time, prices were aligned across the market. The circumstances of this event are detailed under the national market outcomes section.

Figures 57 – 61 set out for each region the extent of capacity offered into the market within a series of price thresholds. Actual price and generation dispatched in a region are overlaid.

Figure 57: Queensland closing bid prices, dispatched generation and spot price

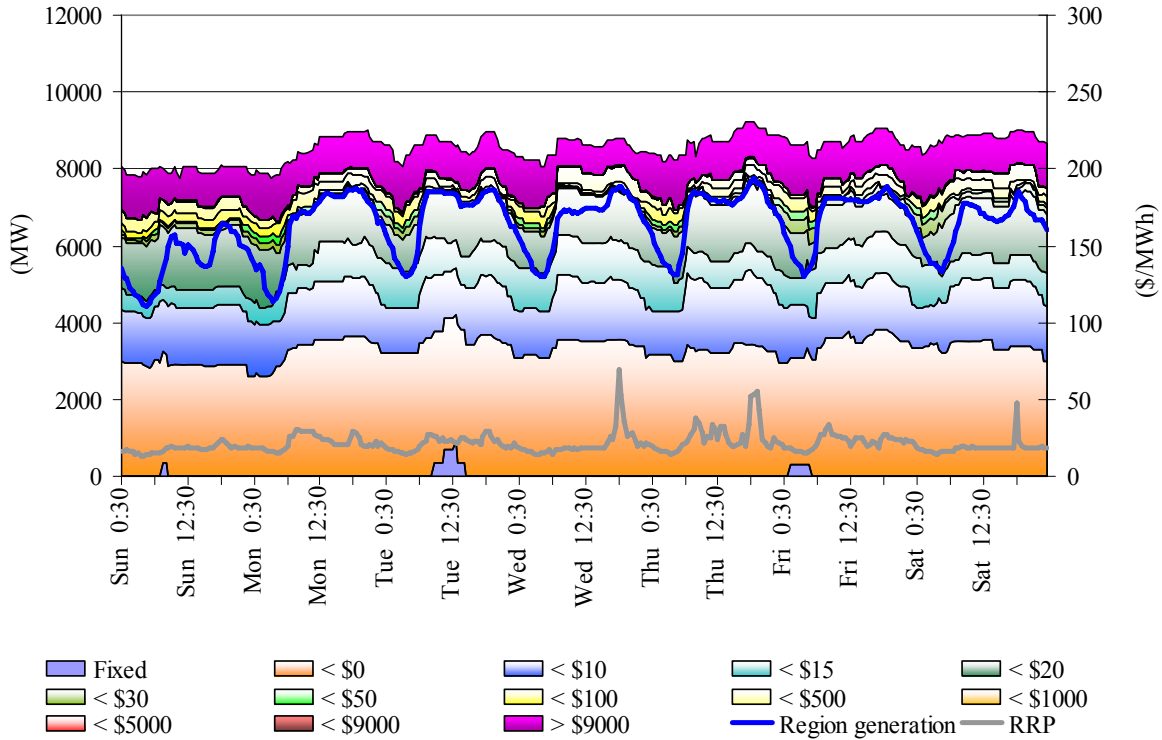


Figure 58: New South Wales closing bid prices, dispatched generation and spot price

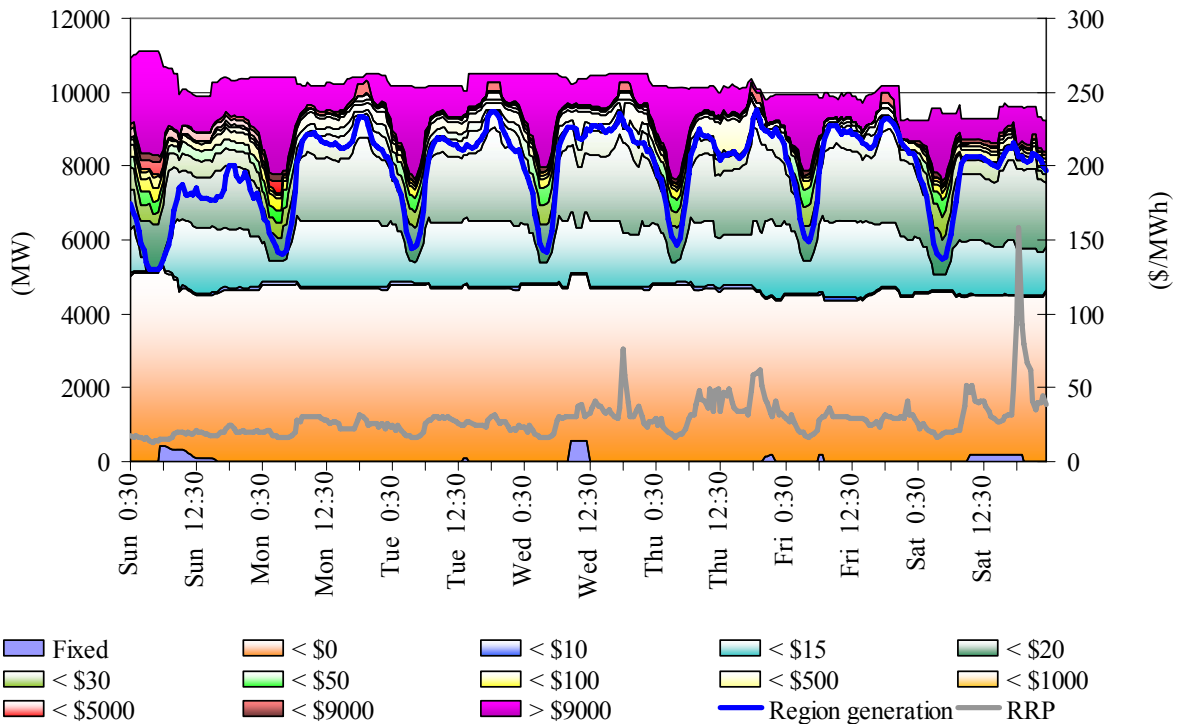


Figure 59: Victoria closing bid prices, dispatched generation and spot price

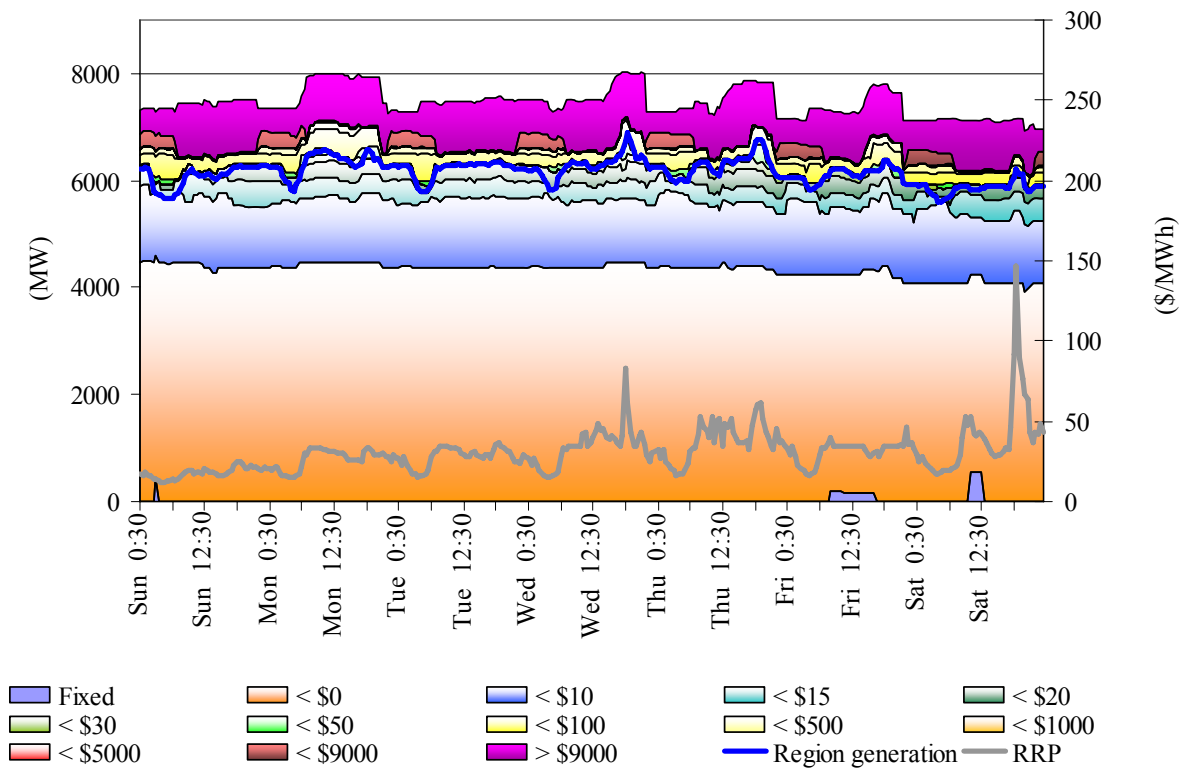


Figure 60: South Australia closing bid prices, dispatched generation and spot price

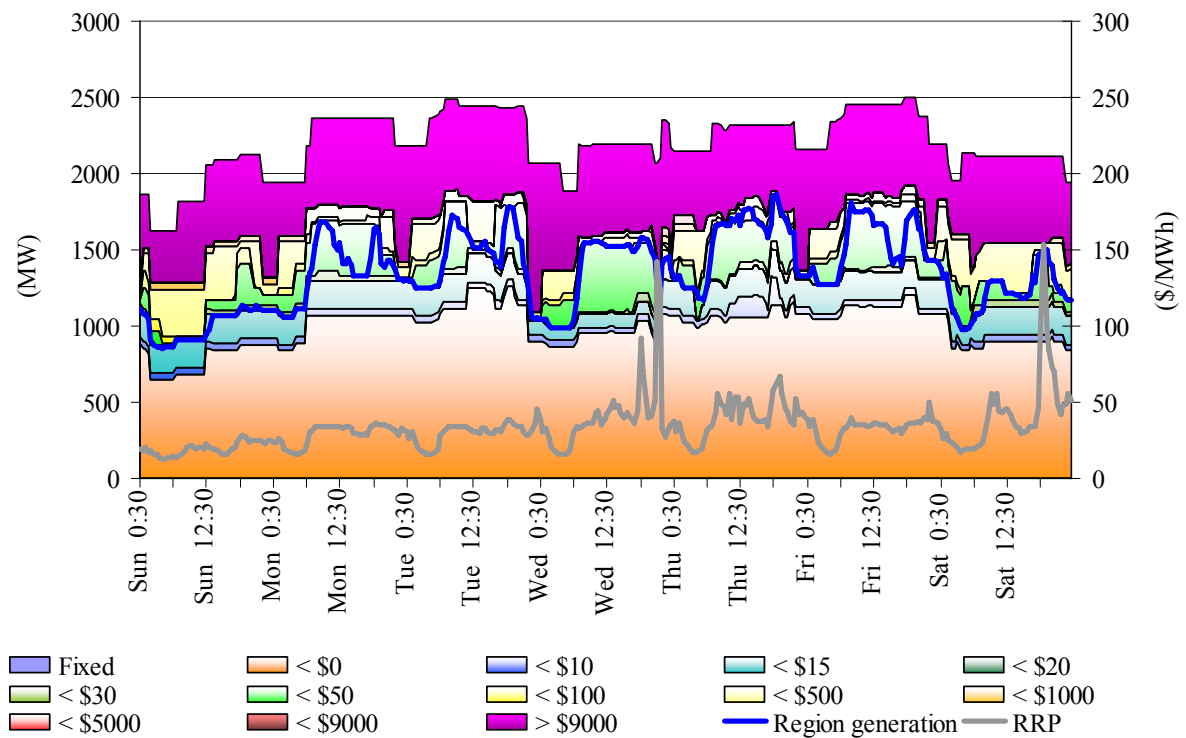
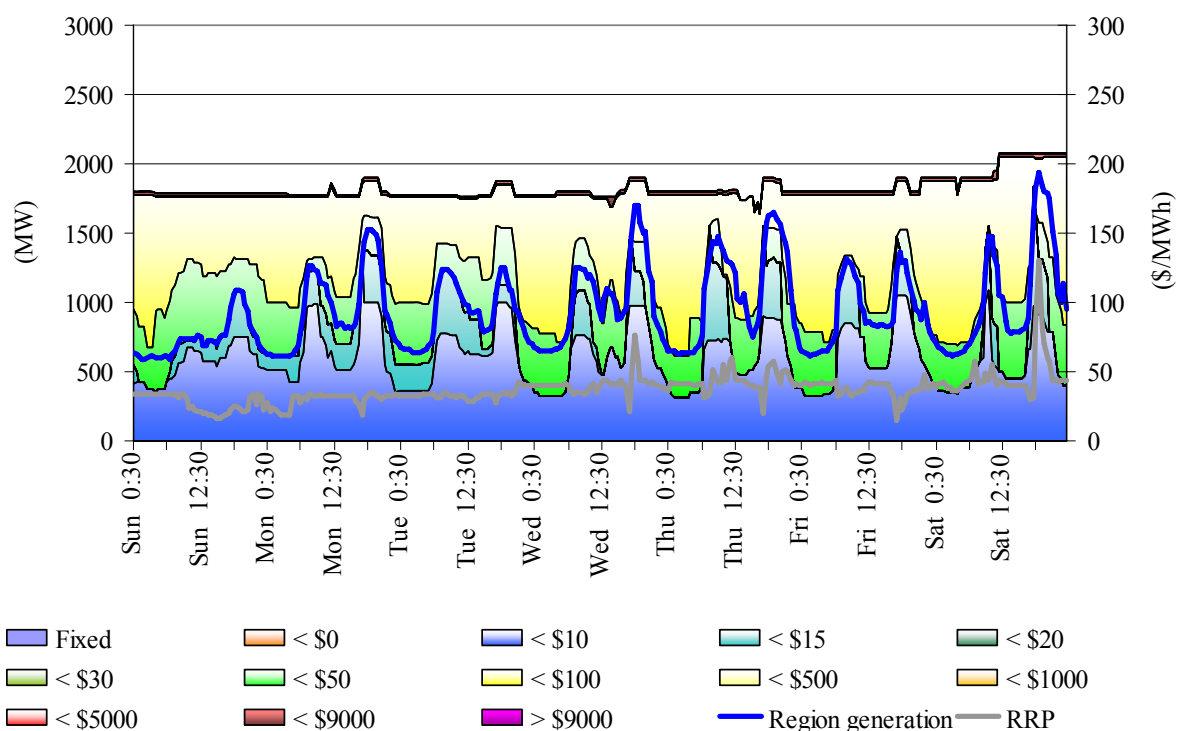


Figure 61: Tasmania closing bid prices, dispatched generation and spot price



Ancillary service market

The total cost of ancillary services on the mainland for the week was \$217 000 or 0.2 per cent of the energy market. Locally sourced lower FCAS were required in Queensland on Wednesday following a planned network outage in northern New South Wales affecting QNI. The costs for locally sourced ancillary services were around \$20 000 during this outage. Figure 62 summarises the volume weighted average prices and costs for the eight frequency control ancillary services across the mainland.

Figure 62: frequency control ancillary service prices and costs for the mainland

	Raise 6 sec	Raise 60 sec	Raise 5 min	Raise reg	Lower 6 sec	Lower 60 sec	Lower 5 min	Lower reg
Last week (\$/MW)	1.46	0.15	0.69	2.95	1.31	0.59	1.22	1.03
Previous week (\$/MW)	0.86	0.11	0.65	1.89	0.93	0.42	0.75	0.90
Last quarter (\$/MW)	1.76	0.73	1.15	1.54	0.39	2.28	5.00	1.93
Market Cost (\$1000s)	\$56	\$5	\$38	\$64	\$4	\$6	\$29	\$15
% of energy market	0.05%	0.01%	0.04%	0.06%	0.01%	0.01%	0.03%	0.01%

The total cost of ancillary services in Tasmania for the week was \$83 000 or 1.0 per cent of the total turnover in the energy market in Tasmania. Figure 63 summarises for Tasmania the prices and costs for the eight frequency control ancillary services.

Figure 63: frequency control ancillary service prices and costs for Tasmania

	Raise 6 sec	Raise 60 sec	Raise 5 min	Raise reg	Lower 6 sec	Lower 60 sec	Lower 5 min	Lower reg
Last week (\$/MW)	4.47	0.85	2.50	2.90	0.05	0.26	0.49	1.01
Previous week (\$/MW)	3.57	0.81	2.20	2.21	0.07	0.30	0.49	0.89
Last quarter (\$/MW)	7.89	1.05	1.05	1.58	4.43	1.06	1.06	1.97
Market Cost (\$1000s)	\$20	\$12	\$28	\$12	\$0	\$2	\$3	\$6
% of energy market	0.26%	0.15%	0.37%	0.16%	0.01%	0.03%	0.03%	0.08%

Figure 64 shows the daily breakdown of cost for each frequency control ancillary service.

Figure 64: daily frequency control ancillary service cost

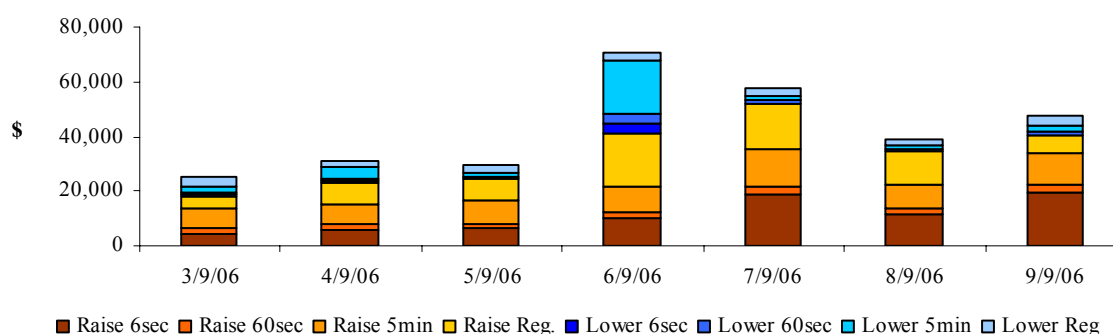
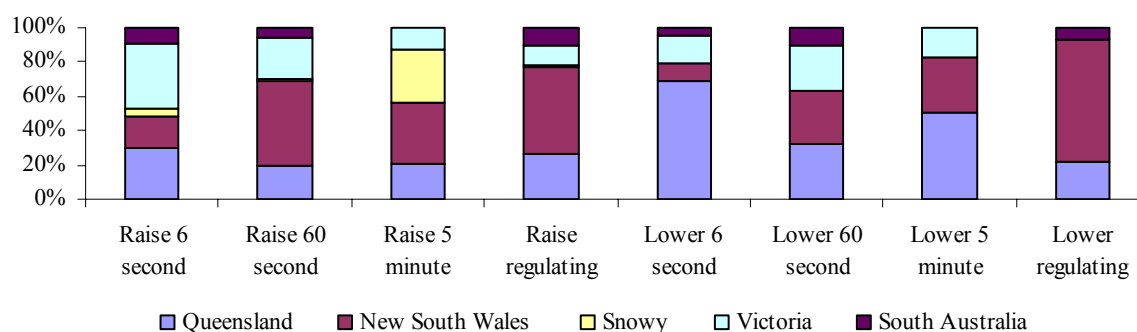


Figure 65 shows the contribution, on a percentage basis, that frequency control ancillary service providers are utilised (in each mainland region) to satisfy the total requirement for each service.

Figure 65: regional participation in ancillary services on the mainland



Figures 66 and 67 show 30-minute prices for each frequency control ancillary service throughout the week.

Figure 66: prices for raise services

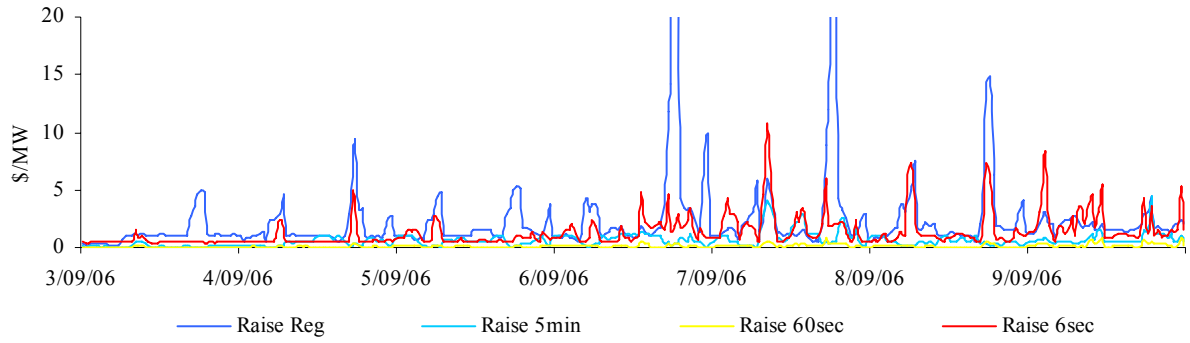


Figure 66A: prices for raise services – Tasmania

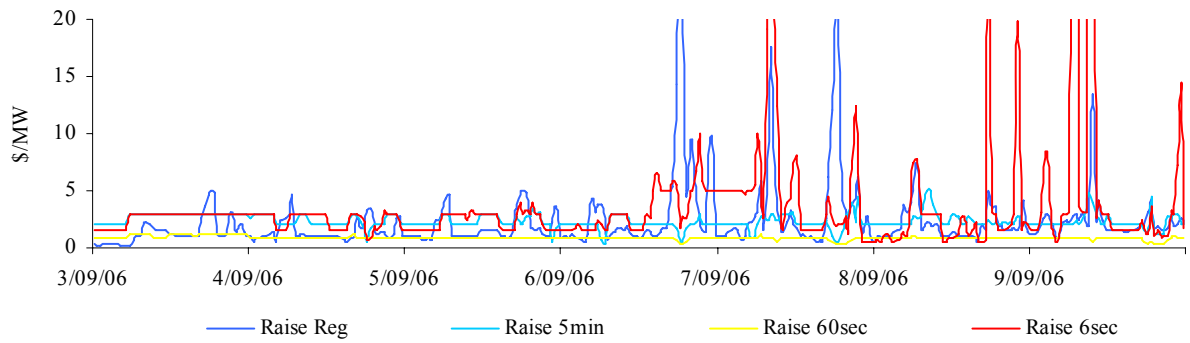


Figure 67: prices for lower services

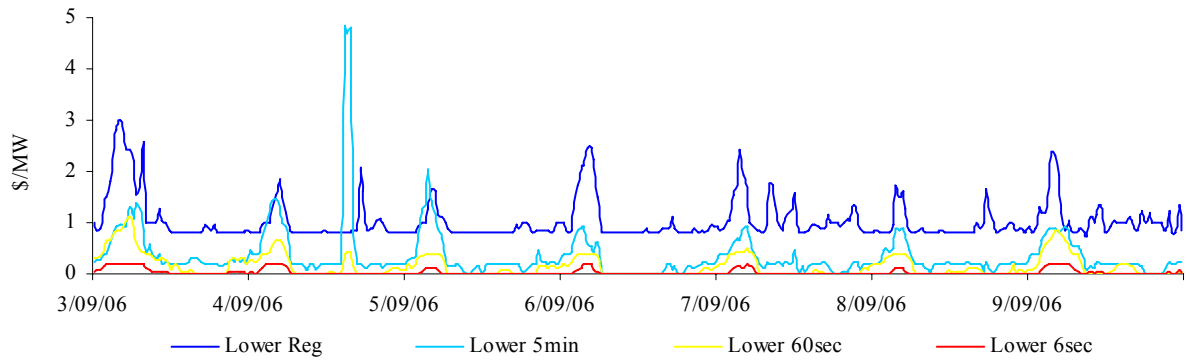
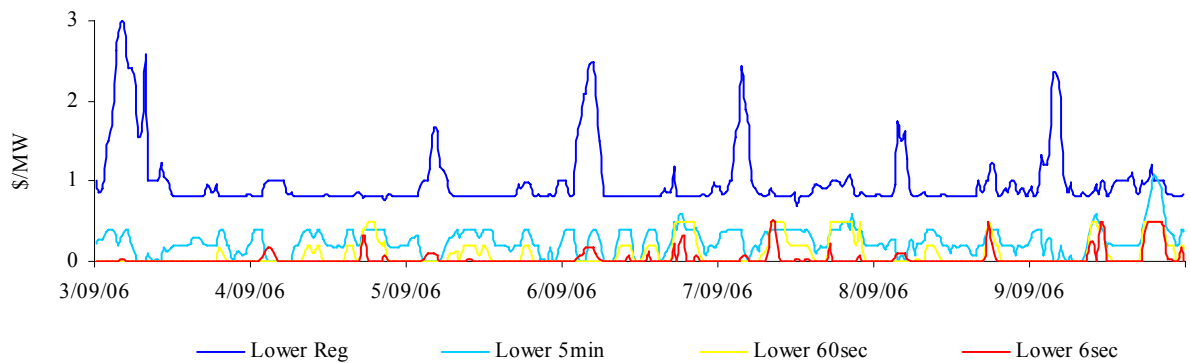


Figure 67A: prices for lower services – Tasmania



Figures 68 and 69 present for both raise and lower frequency control services the requirement, established by NEMMCO, for each service to satisfy the frequency standard.

Figure 68: raise requirements

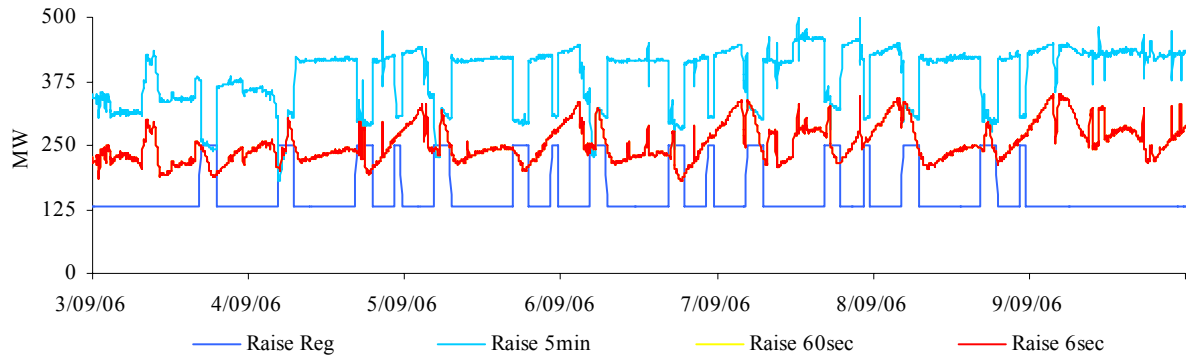


Figure 68A: raise requirements – Tasmania

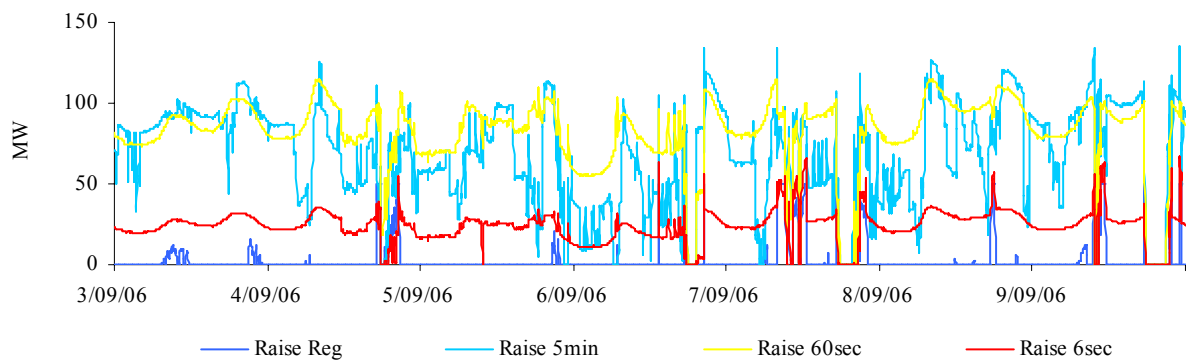


Figure 69: lower requirements

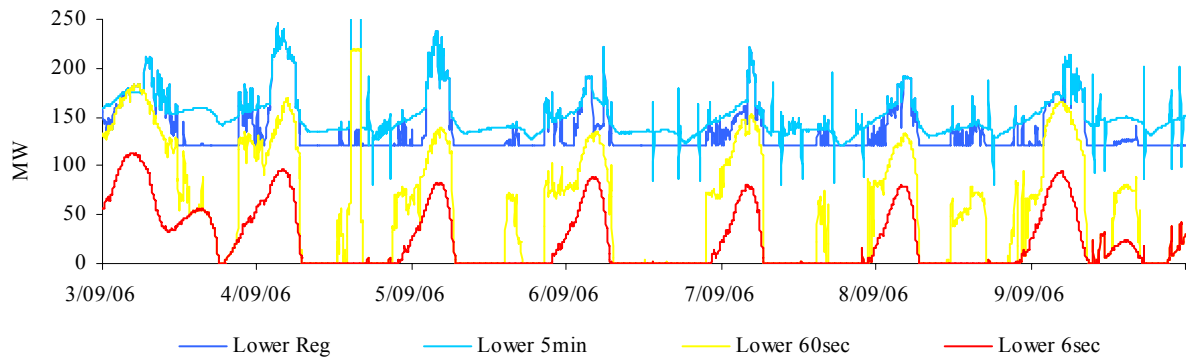


Figure 69A: lower requirements – Tasmania

