Market analysis

18–24 February 2007

Spot prices for the week averaged between $50/MWh in Queensland and $77/MWh in South Australia. High temperatures across the mainland saw demand approach record levels every day of the week.

Turnover in the energy market was $261 million. The total cost of ancillary services for the week was $340 000, or 0.1 per cent of energy market turnover.

Significant variations between actual prices and those forecast 4 and 12 hours ahead occurred in 186 or over a half of all trading intervals. Demand forecasts produced 4 and 12 hours ahead varied from actual by more than 5 per cent in around a quarter all trading intervals across the market. These variations were most frequent in South Australia, occurring in almost two thirds 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

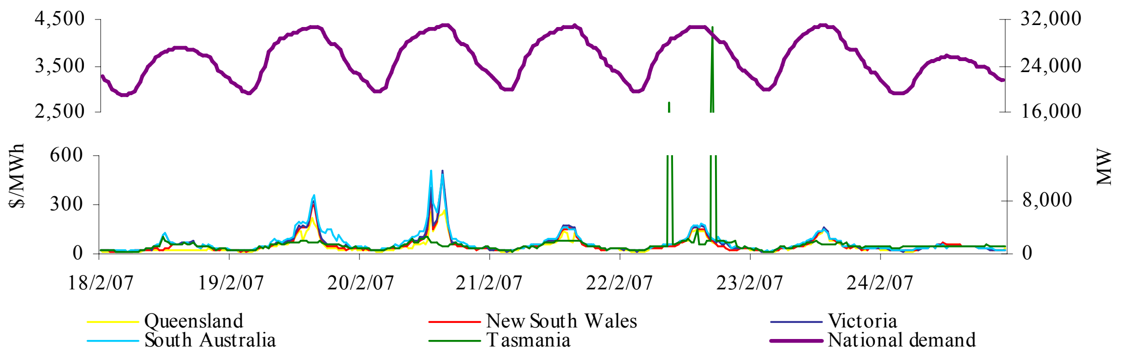


Figure 2: volume weighted average spot price for energy market ($/MWh)

	QLD	NSW	VIC	SA	TAS
Last week	50	61	68	77	71
Previous week	35	53	58	68	54
Same quarter last year	39	46	53	58	33
Financial year to date	35	39	46	51	42
% change from previous week *	▲41%	▲15%	▲17%	▲13%	▲31%
% change from same quarter last year **	▲28%	▲33%	▲28%	▲34%	▲116%
% change from year to date ***	▼2%	▼24%	▲15%	▲5%	▼42%

*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.
***The percentage change between the average spot price for the current financial year to date and the average spot price over the similar period for the previous financial year.

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

Figure 3: Queensland

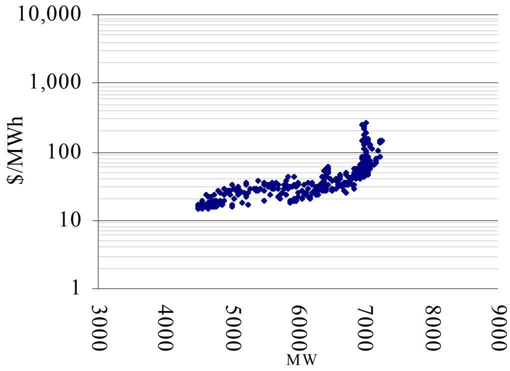


Figure 4: New South Wales

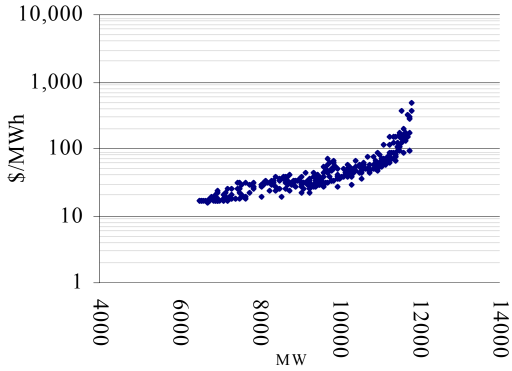


Figure 5: Victoria

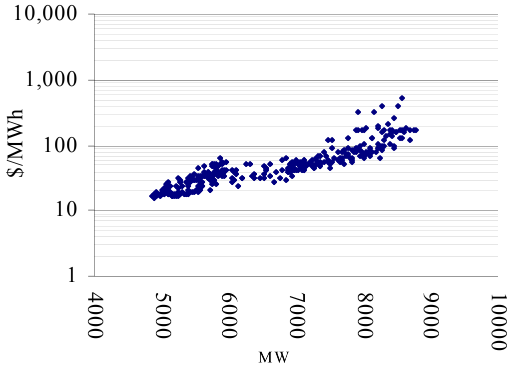


Figure 6: South Australia

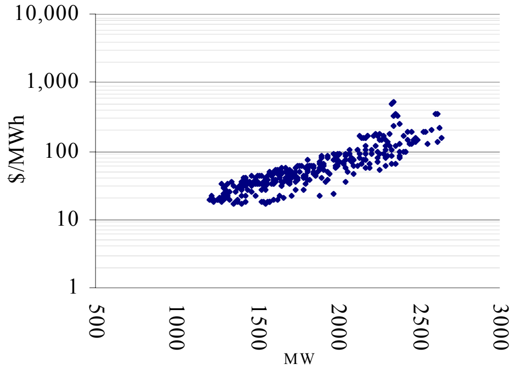
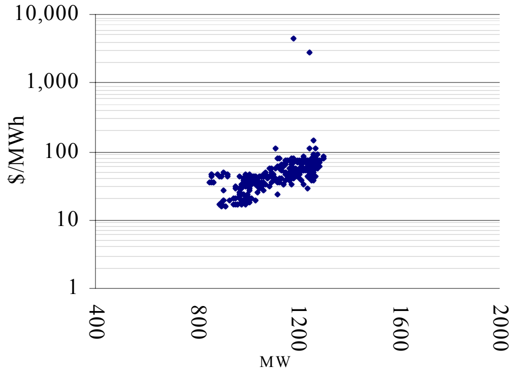


Figure 7: Tasmania



The maximum spot prices for the week ranged from \$260/MWh in Queensland to \$4332/MWh in Tasmania following loss of a number of transmission lines during a thunderstorm. 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	2.18	2.35	2.08	1.59	0.62
Previous week	1.69	1.35	1.25	1.34	0.95
Same quarter last year	1.07	0.96	0.96	0.94	0.29

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

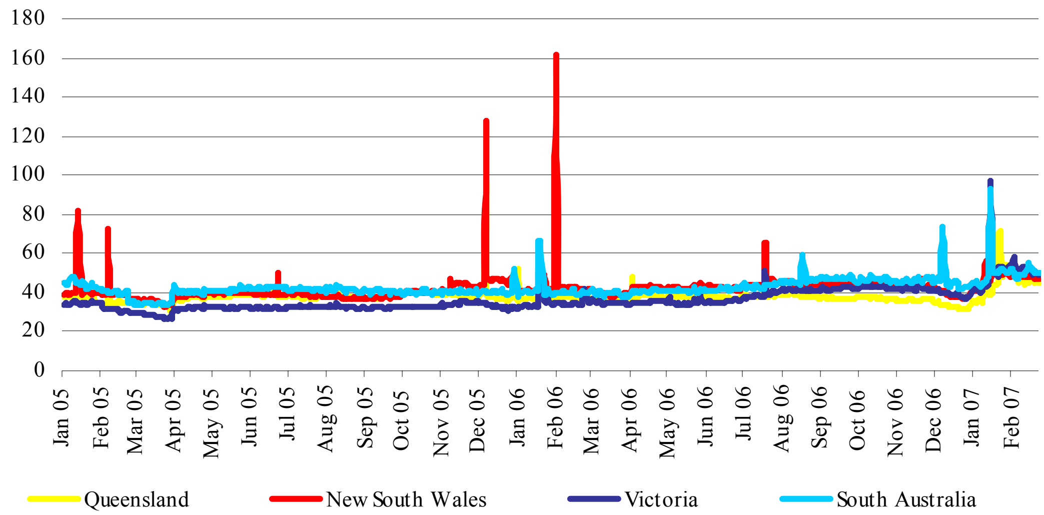
Figure 9 sets out the d-cyphaTrade wholesale electricity price index (WEPI)* for each region throughout the week excluding Tasmania. Figure 10 sets out the WEPI since 1 January 2005.

Figure 9: d-cyphaTrade WEPI for the week

	Monday	Tuesday	Wednesday	Thursday	Friday
Queensland	45.51	45.45	45.41	45.67	44.63
New South Wales	48.08	47.63	46.59	47.48	47.50
Victoria	49.08	51.32	51.28	50.28	49.29
South Australia	51.24	51.13	49.78	50.32	49.93

* The 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
The WEPI applies for working days only.

Figure 10: d-cyphaTrade WEPI



Reserve

Low reserves were forecast in South Australia, between Sunday and Thursday.

Figures 11 to 14 show spot price, net imports and limits at the time of weekly maximum demand.

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

Figure 11: Queensland

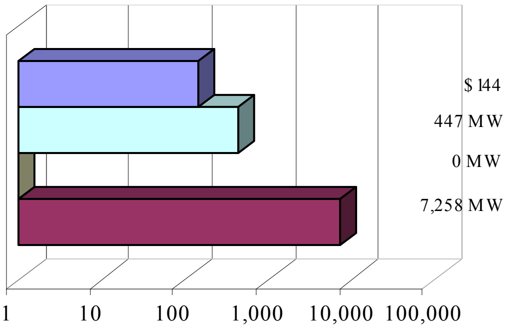


Figure 12: New South Wales

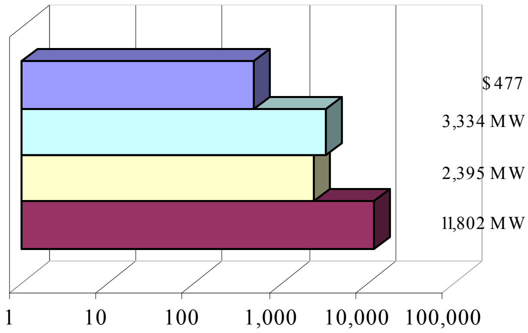


Figure 13: Victoria

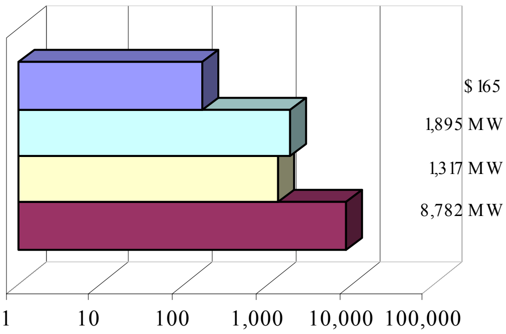


Figure 14: South Australia

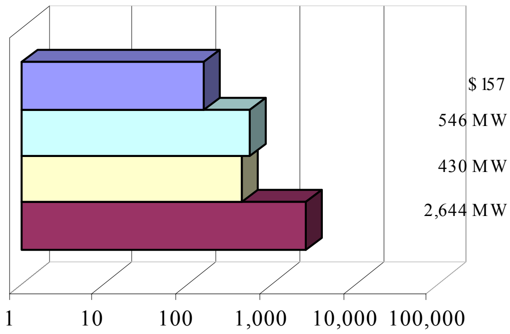
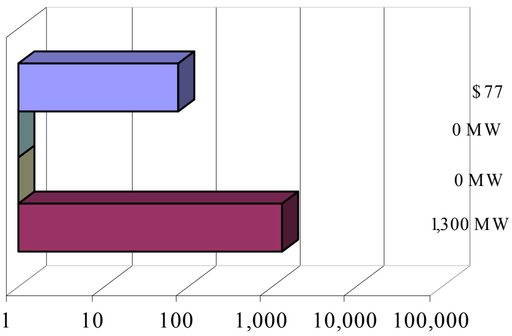
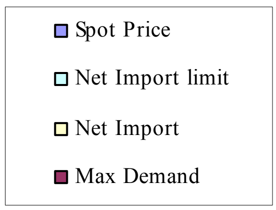


Figure 15: Tasmania





Price variations

There were 186 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

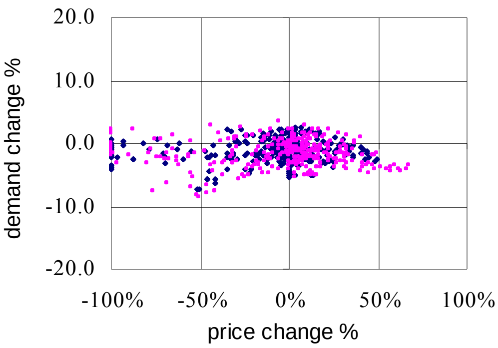


Figure 17: New South Wales

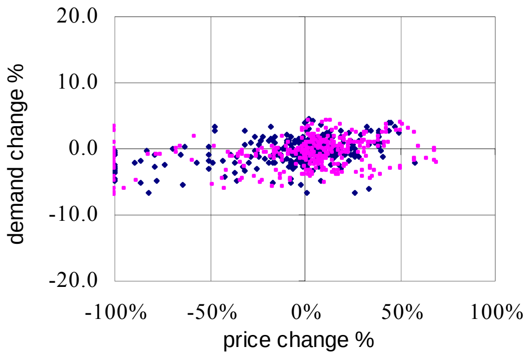


Figure 18: Victoria

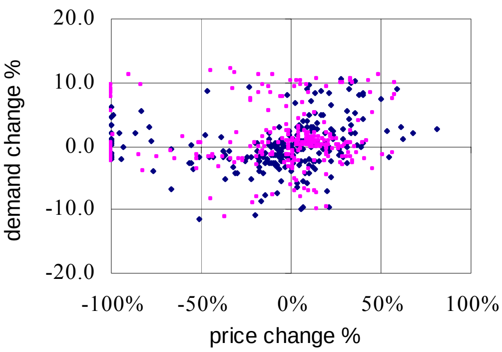


Figure 19: South Australia

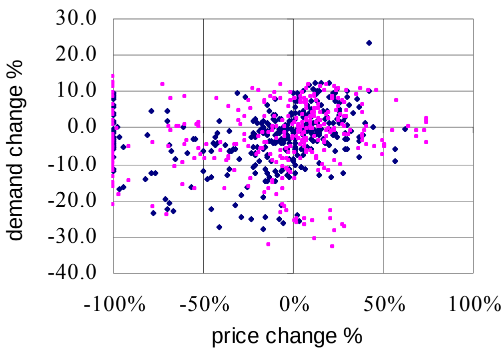


Figure 20: Tasmania

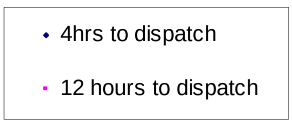
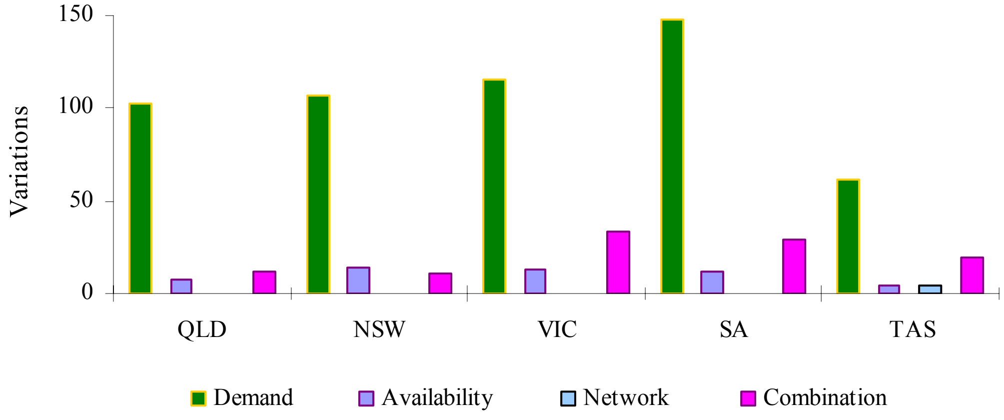


Figure 21 summarises the number and most probable reason for variations between forecast and actual prices.

Figure 21: reasons for variations between forecast and actual prices



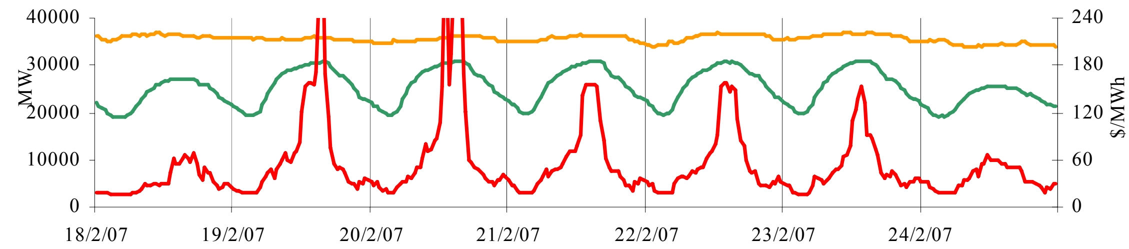
Price and demand

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.

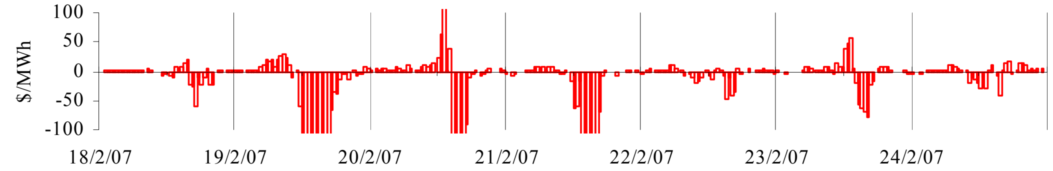
Spot prices within the national market are regularly aligned, with conditions in one region reflected across all others. The national market outcomes section highlights pricing events that occurred when spot prices were generally aligned across all regions of the national electricity market – the New 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.

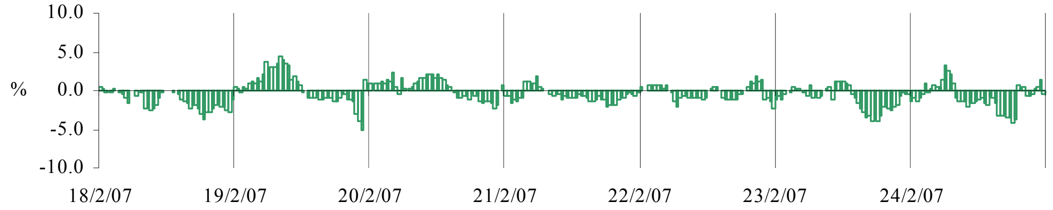
Figures 22-26: National market outcomes



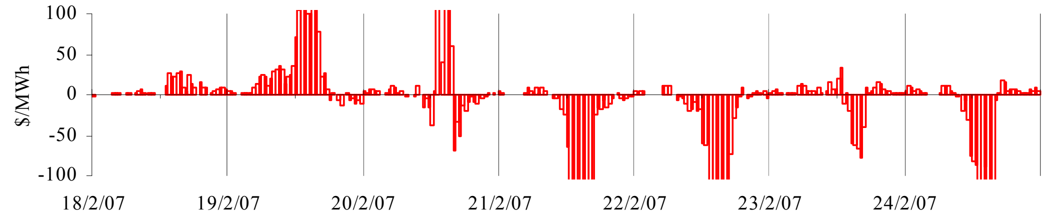
National capacity — National demand — NSW spot price



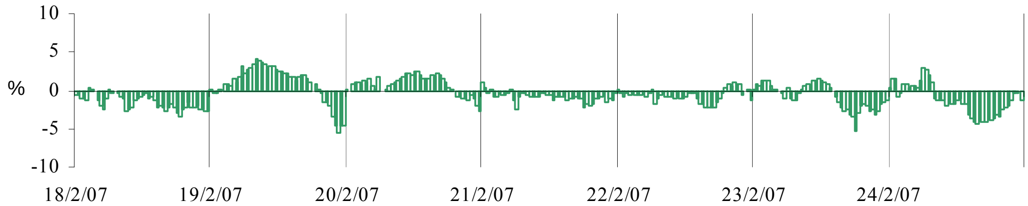
NSW price difference (actual - forecast) - 4hrs



National Demand difference (actual - forecast) - 4hrs



NSW price difference (actual - forecast) -12 hrs



National Demand difference (actual - forecast) - 12hrs

There were seven occasions where spot prices were nationally aligned and the New South Wales price[1] was greater than three times the New South Wales weekly average price of $61/MWh.

Monday, 19 February

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	287.24	1500.00	90.53
Demand (MW)	30 618	30 996	30 245
Available capacity (MW)	35 927	35 911	36 785
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	296.51	6750.51	91.07
Demand (MW)	30 849	31 187	30 313
Available capacity (MW)	35 960	35 787	36 785

Conditions at the time saw demand slightly lower than forecast four and 12 hours ahead but still at near-record levels. Prices were significantly lower than forecast four hours ahead.

Over a series of rebids by Enertrade from early in the morning, capacity at Collinsville and Gladstone was reduced by 184 MW, and then through increased availability or band shifting across the portfolio, the capacity presented at prices of less than $200/MWh was increased by up to 170 MW. The rebid reasons given included “Correct error in previous bid:revise mw avail”, “Rearrangement pre/post outage::change MW distrib” and “Plant problem::change availability”.

Over two rebids at 3.50 am and 7.11 am, Macquarie Generation reduced the availability of Bayswater unit four to zero. This reduced the available capacity priced at less than $20/MWh by 550 MW. The rebid reasons given were “Adjustment due to BW04”, SCC Failure” and “Unit O/S profile”.

A rebid at 4.56 am, reduced the availability of Delta Electricity’s Mount Piper unit two, which was returning to service that day, by 300 MW. All but 40 MW of this capacity was priced at less than $20/MWh. The rebid reason given was “Return to service::Unit RTS”.

From 7.11 am, TRUenergy increased the availability of capacity at Torrens Island priced below $200/MWh by up to 330 MW. Much of this capacity was previously priced above $9000/MWh, with some coming from increases in availability following the commitment of the A2 unit. The rebid reasons given included “Market conditions – Gen response to PD conditions” and “Plant conditions – Adj to unit commitment”.

From 7.45 am Origin Energy rebid 366 MW of capacity from prices above $9000/MWh into prices of zero across its portfolio. The rebid reasons given were “Change in PDS”.

From 7.56 am, AGL Hydro rebid as much as 540 MW of capacity into prices of zero. As much as 310 MW of this capacity had previously been priced above $9000/MWh. The rebid reasons given included “Predispatch – forecast price change:prices” and “Plant limitations::Pondage constraints”.

From 8.53 am, Stanwell rebid 150 MW of capacity from prices of less than $20/MWh into prices around $270/MWh. The rebid reason given was “Portfolio optimisation”.

From 10.12 am, Tarong Energy reduced the capacity priced at less than $20/MWh by 108 MW through a combination of rebids that reduced available capacity and shifting capacity into prices of around $300/MWh. The rebid reasons given included “Avoid mill

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

cycling::volume profile change”, Tarong North Ash problems” and “Response to interconnector constraint::volume profile”.

At 11.51 am, Callide Power Trader rebid 194 MW of capacity from prices of less than $20/MWh to above $9000/MWh. The rebid reason given was “Optimisation decision::change MW dist”.

From midday, International Power shifted as much as 156 MW of capacity in South Australia into prices of less than $100/MWh from prices above $9000/MWh. The rebid reasons given included “Commit unit due to PD price change” and “Change in price forecast, demand above forecast”.

At 1.32 pm 220 MW of capacity at Yallourn was shifted from prices below $5/MWh to above $9000/MWh. The rebid reasons give was “PD conditions changed @ hour ending 1300”. The forecast price for Victoria had fallen over two predispatch forecasts from $9000/MWh to $1700/MWh just prior to this rebid.

There was no other significant rebidding.

Tuesday, 20 February

1:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	360.15	153.42	153.48
Demand (MW)	30 427	30 031	29 854
Available capacity (MW)	35 704	36 000	35 821
2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	193.25	156.12	152.34
Demand (MW)	30 640	30 473	30 186
Available capacity (MW)	36 010	35 736	36 123
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	313.63	470.68	154.20
Demand (MW)	30 788	30 817	30 321
Available capacity (MW)	36 191	35 788	36 123
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	477.06	2500.00	234.69
Demand (MW)	30 999	31 102	30 375
Available capacity (MW)	36 299	35 927	36 123
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	364.55	5488.23	305.22
Demand (MW)	31 000	31 297	30 434
Available capacity (MW)	36 201	35 916	36 149

Conditions at the time saw demand at near-record levels and close to forecast. Prices were aligned across the mainland with Tasmania exporting as much as 565 MW.

Over a number of rebids from 6.42 am, AGL Hydro shifted as much as 484 MW of capacity into prices of less than $100/MWh. Most of this capacity had been priced at more than $9000/MWh. The rebid reasons given included “Portfolio optimisation:changed energy band” and “Plant failure:STN unit return to service”.

From 8.33 am, Origin Energy rebid as much as 510 MW of capacity, from across its portfolio, into prices of zero from above $9000/MWh. The rebid reasons given were “Change in PDS” and “Change in PDS and availability”.

Following an earlier 110 MW availability reduction at around 8 am, Millmerran unit two was shutdown at 9.30 am. All of this capacity had been priced at less than zero. The rebid reason given was "Changed plant conditions" and "Forced outage".

From 8.07 am, Delta Electricity reduced the availability of Vales Point unit five by 160 MW due to plant issues related to temperature and milling. At Wallerawang 80 MW of capacity was rebid into prices above $9000/MWh from below $20/MWh. The rebid reason given was "Prod change MP2/Price higher than expected:band shift". A further 100 MW of capacity was rebid at Wallerawang from prices below $255/MWh to above $9000/MWh. The rebid reason given was "Price higher than expected::band shift".

Over a number of rebids from 8.39 am, TRUenergy increased the capacity available at lower prices at Torrens Island. In total, around 310 MW of capacity was added at prices of less than $200/MWh through a combination of the commitment of Torrens Island A unit two at 10.42 am and rebidding from prices above $9000/MWh. The rebid reasons given were "Market conditions-gen response to PD conditions"

From 9.38 am, Tarong Energy shifted 105 MW of capacity from prices of less than $150/MWh to prices around $300/MWh and $4000/MWh. The rebid reasons given were "Interconnector limit::Volume profile change", "Dispatch deviation from predispatch::volume profile" and "Response to transmission constraint:volume profile". At times, actual export capability across QNI into New South Wales was 200 MW lower than forecast.

From 10.46 am, International Power rebid as much as 156 MW of capacity from prices above $5000/MWh into prices of less than $100/MWh across its portfolio in South Australia. The rebid reasons given included "Change in price forecast" and "Fuel management".

At 11.53 am, Macquarie Generation shifted 180 MW of capacity from prices of less than $20/MWh to above $4000/MWh. The rebid reason given was "Load expected to vary from forecast".

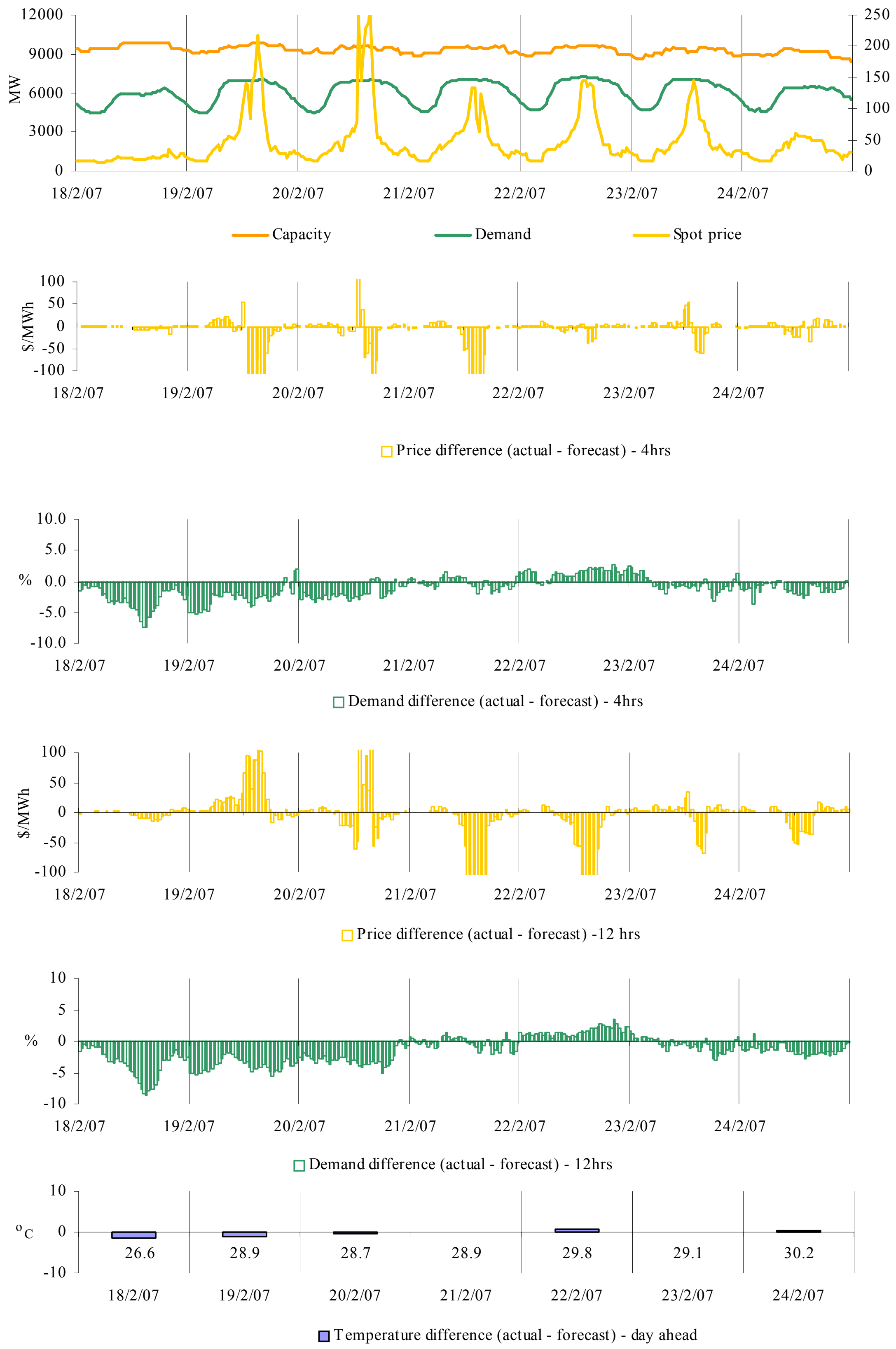
From 12.31 pm, over a number of rebids, made close to dispatch, Stanwell Corporation shifted as much 230 MW of capacity at Stanwell from prices of less than $100/MWh into higher prices, including above $9000/MWh. The rebid reasons given were "Manage transmission constraint", "Correct error in previous bid" and "Changed predispatch".

At 12.46 pm, CS Energy rebid 105 MW of capacity from prices of less than $100/MWh to prices around $300/MWh. The rebid reason given was "CS portfolio manage constraint".

LYMMCO's Loy Yang A unit three returned to service at 2 pm following a short outage. This return was around five hours earlier than previous forecasts resulting in an increase in capacity at low prices.

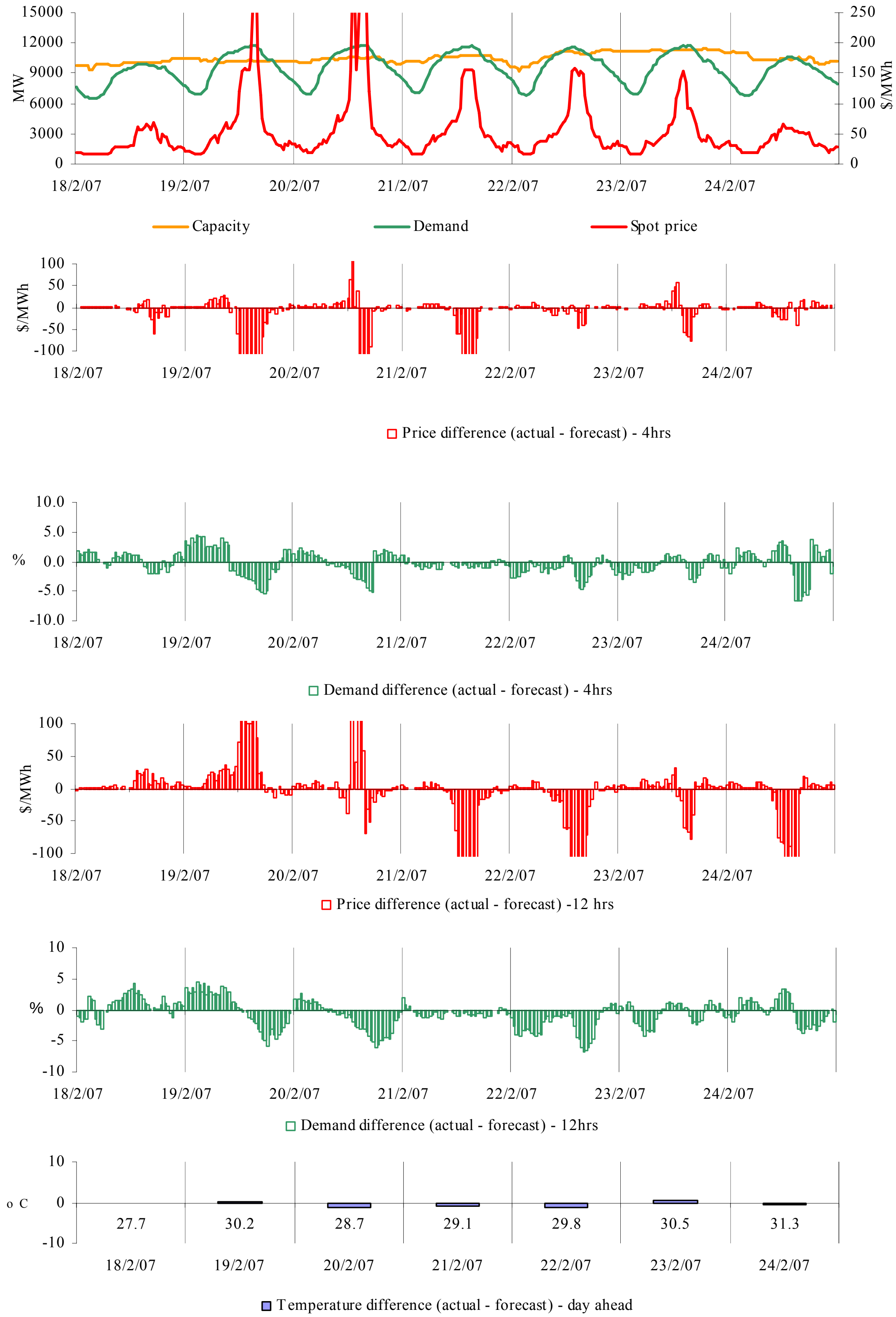
There was no other significant rebidding.

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



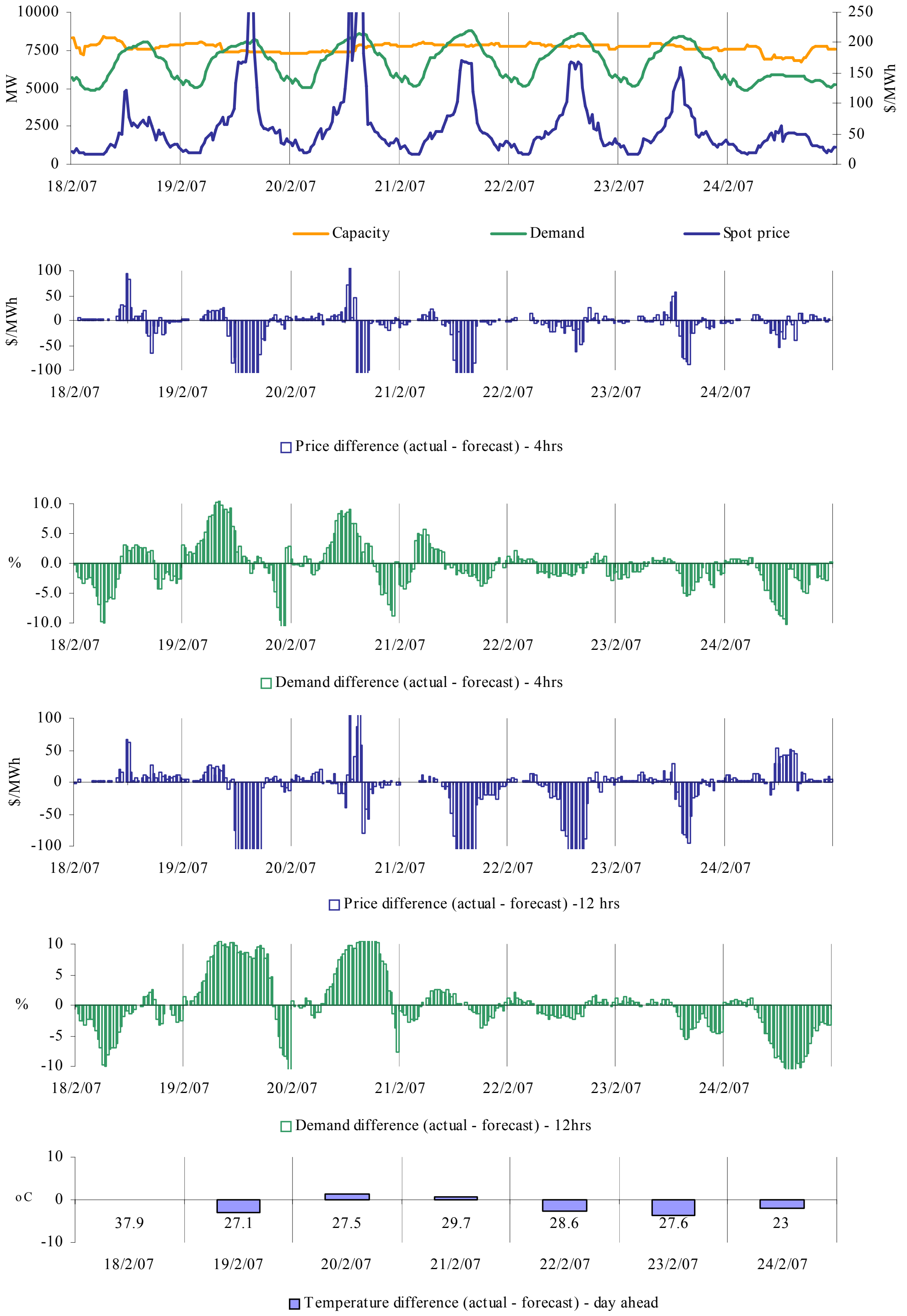
There were ten occasions in Queensland where the spot price was greater than three times the weekly average price of $50/MWh. At the time, prices were aligned across the market. The circumstances of these events all occurred on days detailed under the national market outcomes section.

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



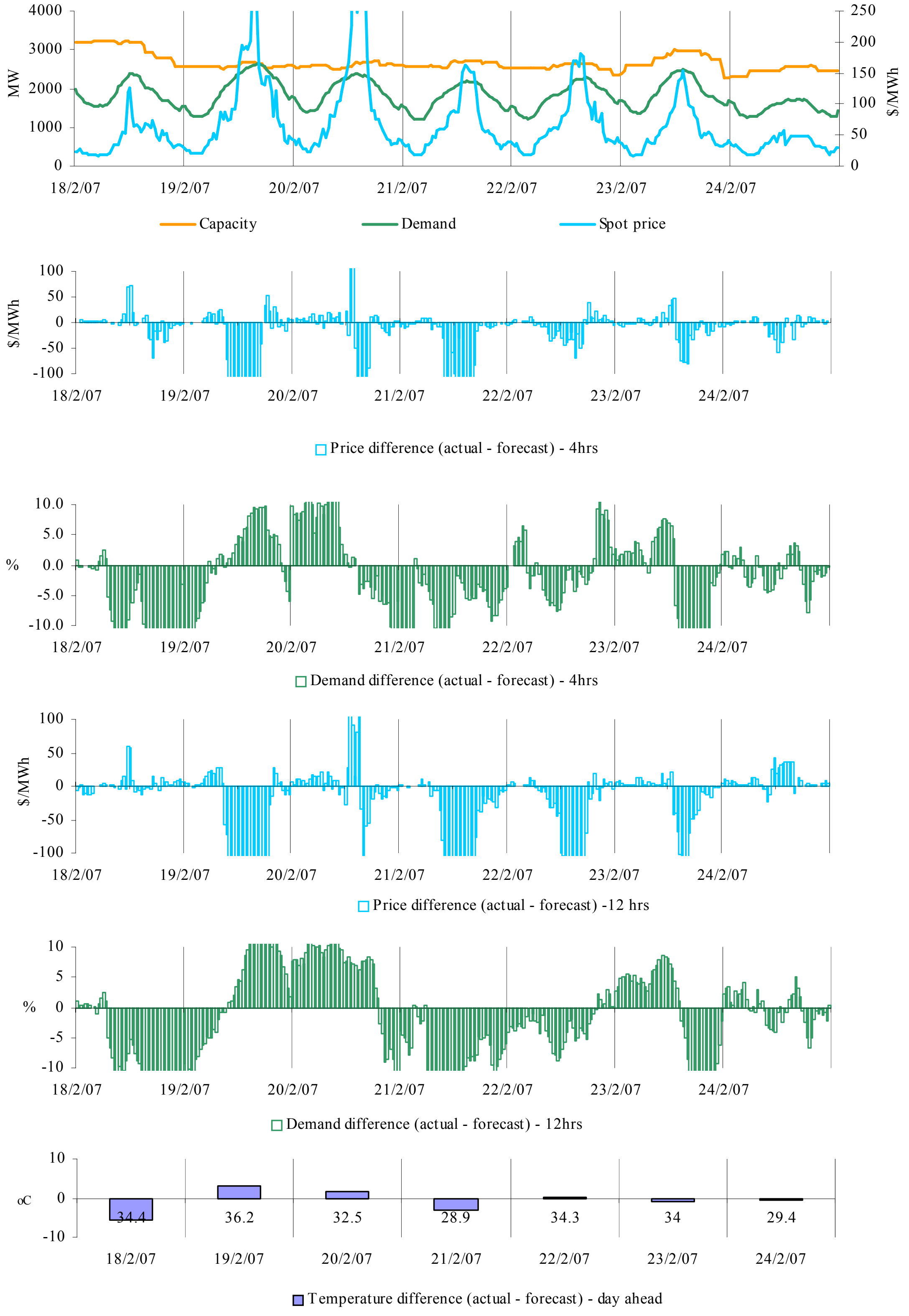
There were seven occasions where the spot price in New South Wales was greater than three times the New South Wales weekly average price of $61/MWh. At the time, prices were aligned across the market. The circumstances of these events are detailed under the national market outcomes section.

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



There were seven occasions in Victoria where the spot price was greater than three times the weekly average price of $68/MWh. At the time, prices were aligned across the market. The circumstances of these events are detailed under the national market outcomes section.

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



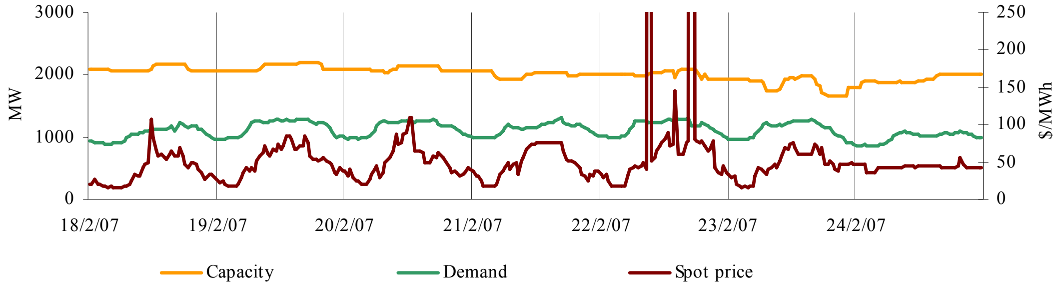
There were eight occasions in South Australia where the spot price was greater than three times the weekly average price of $77/MWh. Seven of these occurred when prices were generally aligned across all regions and are detailed in the national market outcomes section. The remaining occasion is presented below.

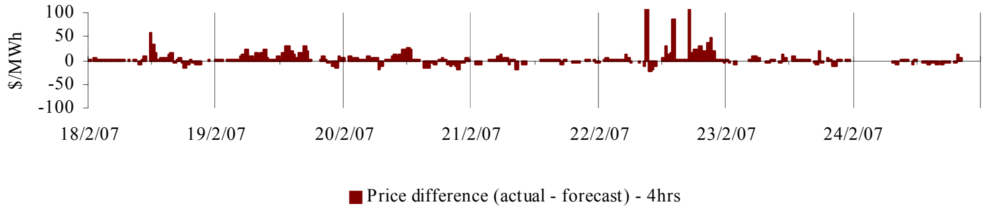
Tuesday, 20 February

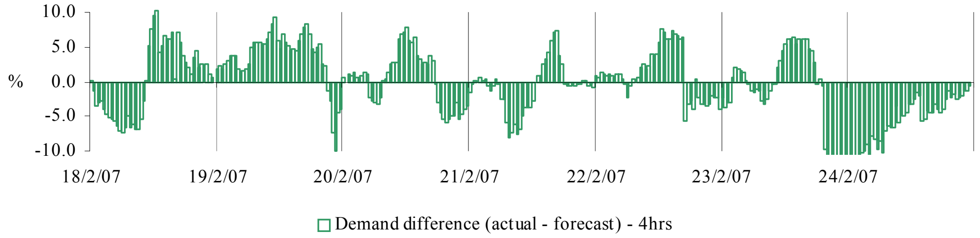
2:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	316.73	188.38	226.10
Demand (MW)	2372	2341	2203
Available capacity (MW)	2670	2497	2576

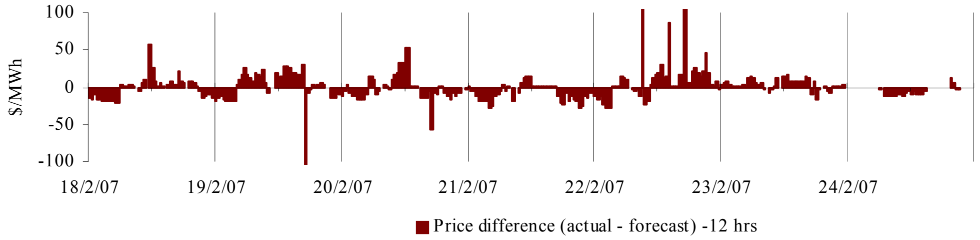
Conditions at the time saw prices aligned with the rest of the mainland for most of the day. From 10 am to 8.30 pm the Victoria to South Australia interconnector was operating at a reduced limit as a result of lightning in south eastern South Australia. For the 2 pm trading interval, the limit reduced to as low as 30 MW and prices diverged from the rest of the mainland.

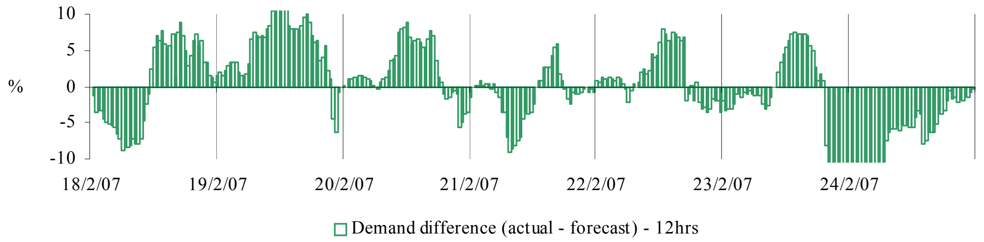
Figures 51-56: Tasmania actual spot price, demand and forecast differences

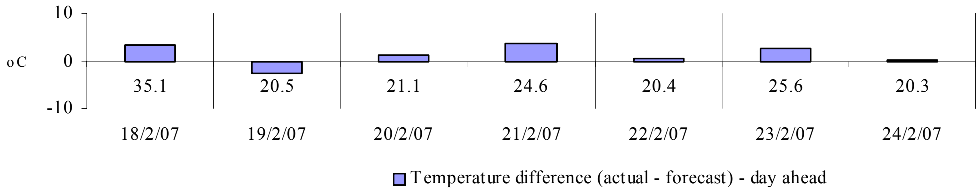












There were two occasions where the spot price in Tasmania was greater than three times the weekly average price of $71MWh.

Thursday, 22 February

9:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2701.14	66.07	67.24
Demand (MW)	1244	1214	1214
Available capacity (MW)	1999	1957	1957

Conditions at the time saw demand close to forecast four and twelve hours ahead. Five minute dispatch prices increased from $52/MWh to $8000/MWh at 9.05 am and remained at this level for the next dispatch interval before returning to previous levels at 9.15 am.

A network limitation between western and northern Tasmania restricted the dispatch of lower priced generation over these two dispatch intervals. This resulted in no available capacity in Tasmania priced between $60/MWh and $8000/MWh, with 1 MW of capacity dispatched at $8000/MWh setting the price during these two dispatch intervals.

There was no significant rebidding.

Thursday, 22 February

5:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4332.13	75.08	75.12
Demand (MW)	1181	1247	1204
Available capacity (MW)	2081	2081	1980

Conditions at the time saw demand lower than forecast four hours ahead

At 4 pm a problem at Gordon Power Station led to the possibility of the loss of two Gordon units. As a result NEMMCO increased the requirement for local frequency control raise ancillary services. At high flows out of Tasmania across Basslink, this had no impact.

At 5.03 pm two Farrell to Sheffield lines tripped as a result of lightning in the vicinity, which resulted in the loss of around 130 MW of load and 580 MW of generation. This reduced flows across Basslink into Victoria, which increased the dispatch of local frequency control raise ancillary services.

The increase in the dispatch of local frequency control ancillary services saw the price of the raise 6 second service increase to $8200/MW, the energy price increased to a similar level. Prices remained at these levels for three five-minute dispatch intervals, returning to previous levels at 5.25 pm.

A rebid by Hydro Tasmania at 5.16 pm, effective from 5.25 pm, shifted 107 MW of capacity from prices of $250/MWh and above into prices of $100/MWh.

There was no significant rebidding.

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

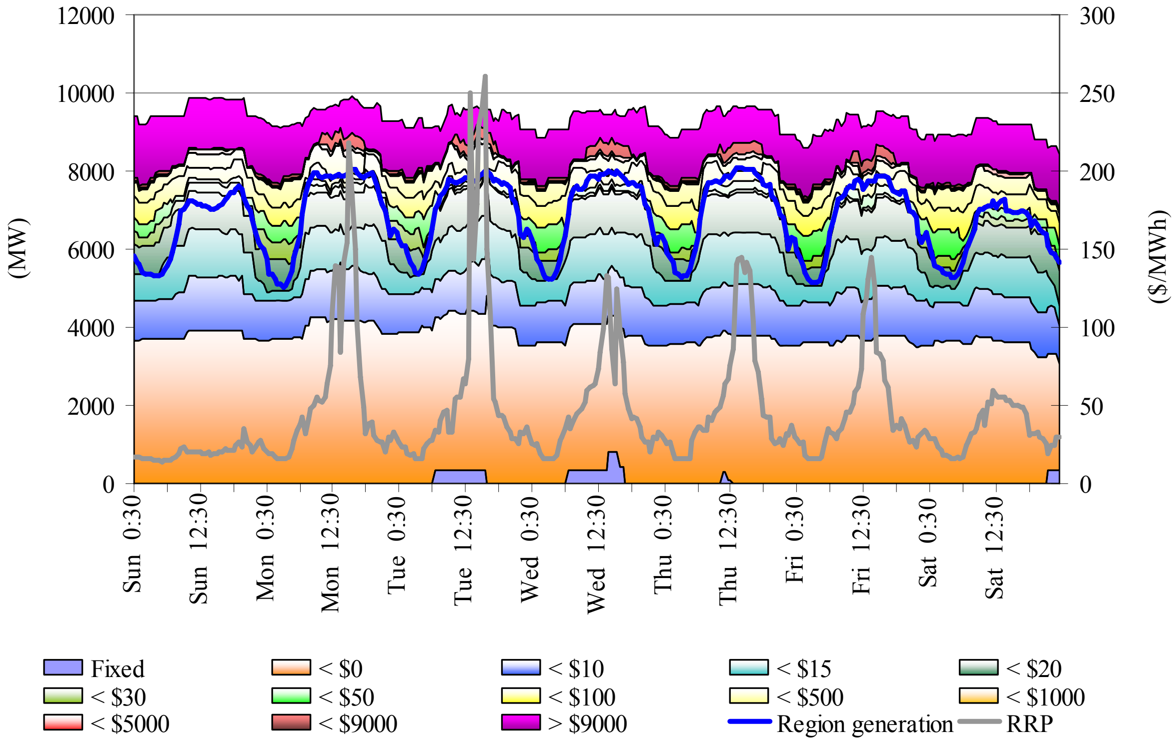


Figure 58: New South Wales closing bid prices, dispatched generation and spot price

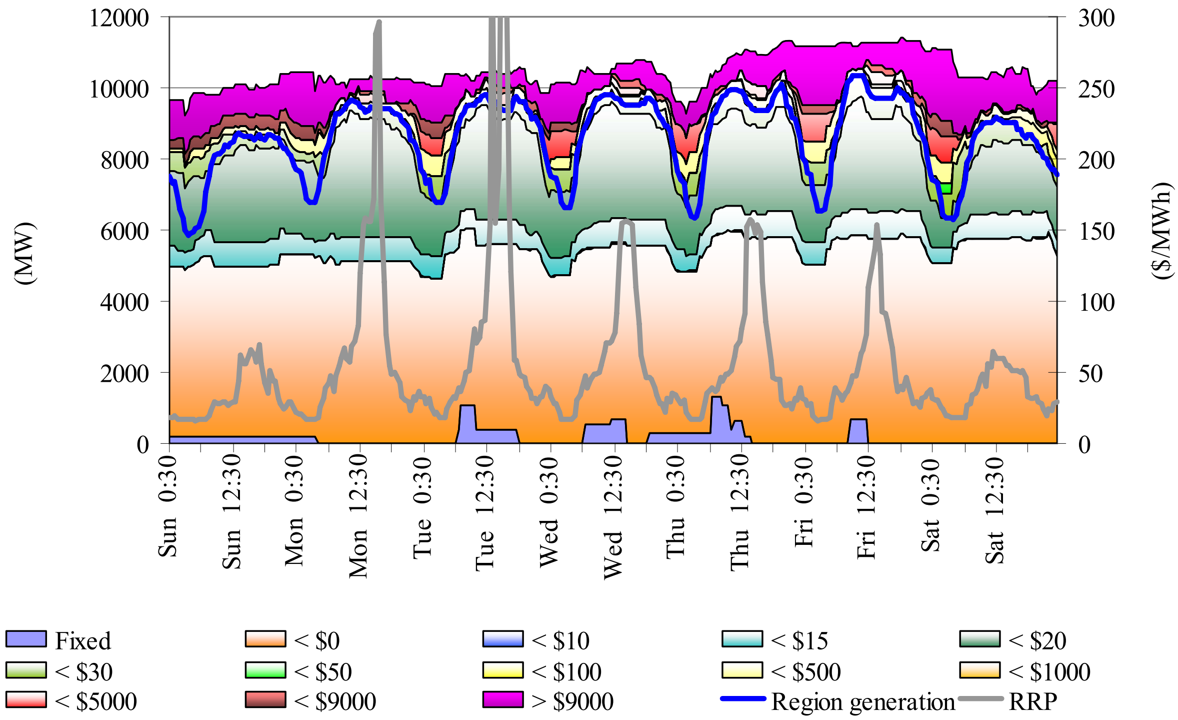


Figure 59: Victoria closing bid prices, dispatched generation and spot price

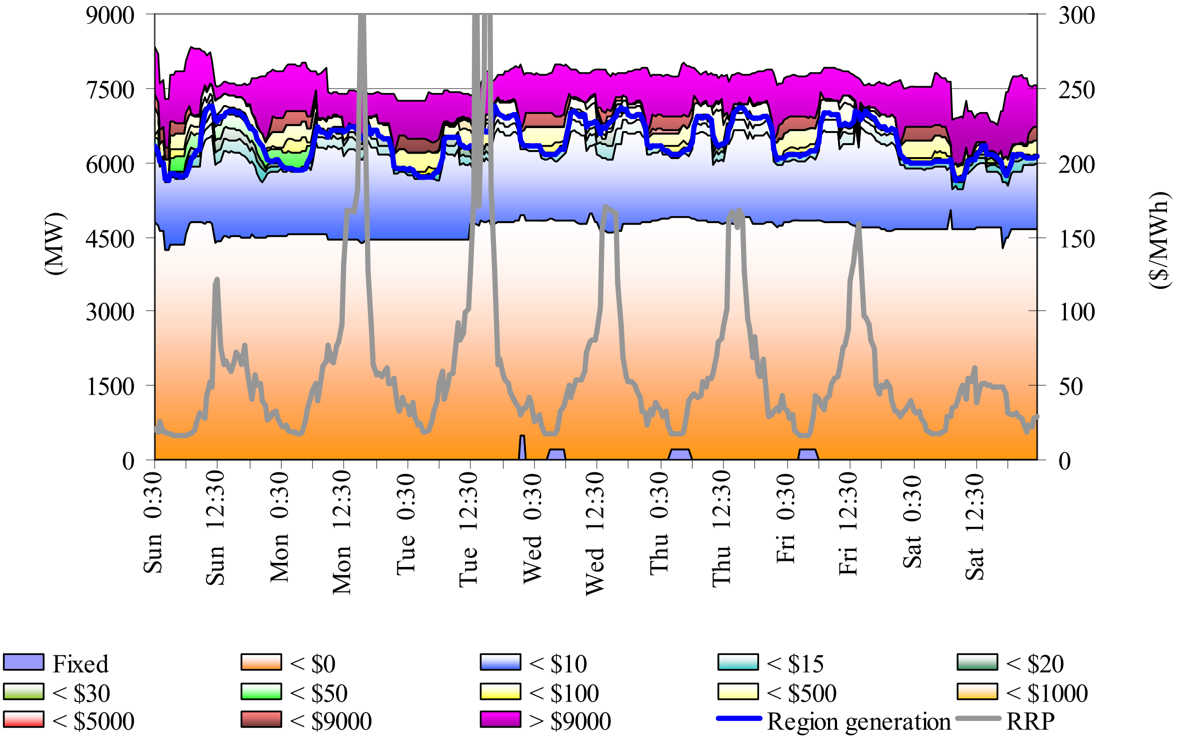


Figure 60: South Australia closing bid prices, dispatched generation and spot price

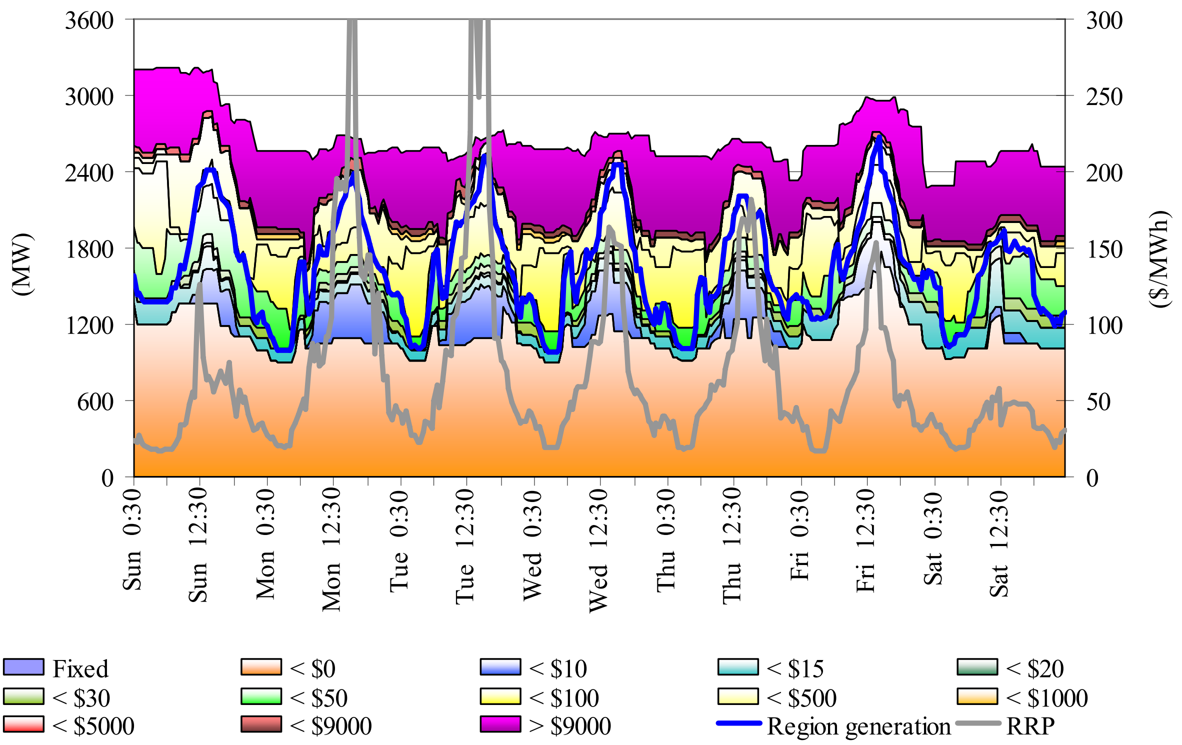
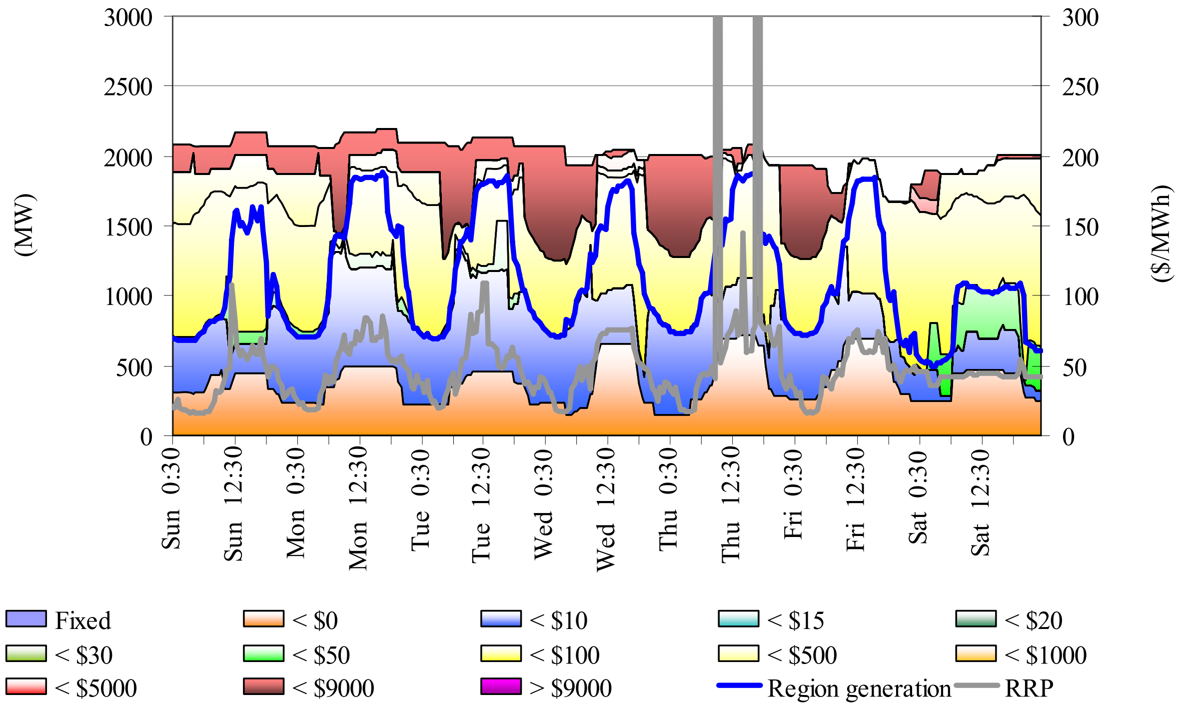


Figure 61: Tasmania closing bid prices, dispatched generation and spot price



Ancillary service market

The total cost of ancillary services on the mainland for the week was $ 157 000 or 0.1 per cent of the energy market. 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 ($/MW)	0.49	0.28	1.10	2.42	0.10	0.07	0.41	0.81
Previous week ($/MW)	0.46	0.28	1.01	2.47	1.90	0.49	2.94	0.93
Last quarter ($/MW)	1.76	0.73	1.15	1.54	0.39	2.28	5.00	1.93
Market Cost ($1000s)	$19	$10	$66	$45	$0	$0	$6	$11
% of energy market	0.01%	0.01%	0.03%	0.02%	0.01%	0.01%	0.01%	0.01%

The total cost of ancillary services in Tasmania for the week was $182 000 or 1.4 per cent of the total turnover in the energy market in Tasmania. On Thursday following the reclassification of the loss of two generating units, NEMMCO increased the requirement for raise services in Tasmania. Following the loss of transmission lines and generation at around 5 pm, the raise 6 second service price increased to more than $8000/MW for three five-minute dispatch intervals. 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 ($/MW)	26.37	0.52	0.71	1.70	5.12	1.12	0.73	0.59
Previous week ($/MW)	1.73	0.51	0.65	1.86	0.32	0.93	0.83	0.77
Last quarter ($/MW)	4.97	0.49	2.93	3.00	12.67	0.43	0.82	0.45
Market Cost ($1000s)	$88	$4	$6	$14	$33	$21	$11	$5
% of energy market	0.67%	0.03%	0.04%	0.10%	0.25%	0.16%	0.08%	0.04%

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

Figure 64: daily frequency control ancillary service cost

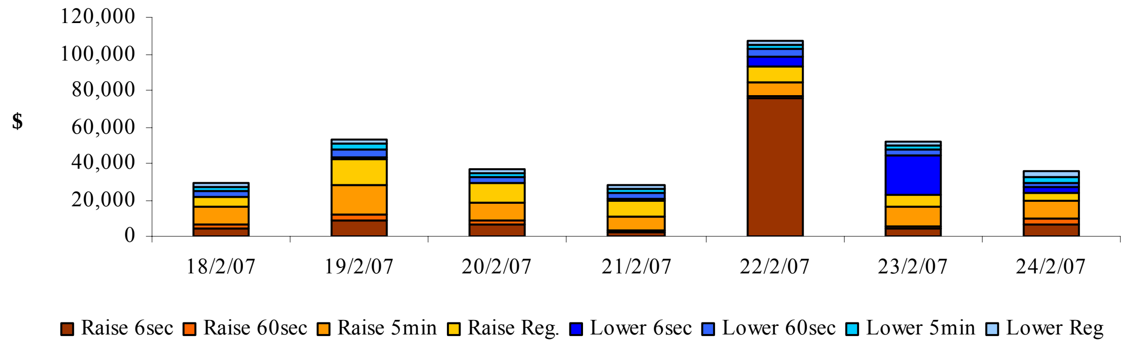
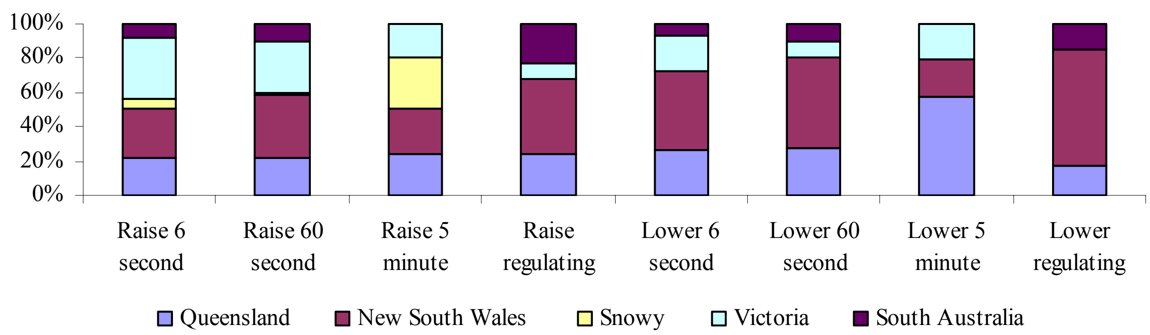


Figure 65 shows the contribution, on a percentage basis, that frequency control ancillary service providers are utilised (in each mainland region) to satisfy the total requirement for each service.

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

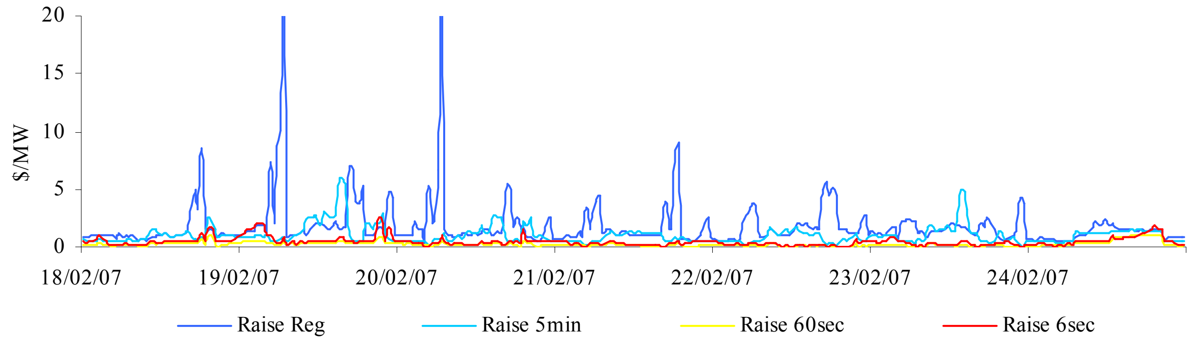


Figure 66A: prices for raise services – Tasmania

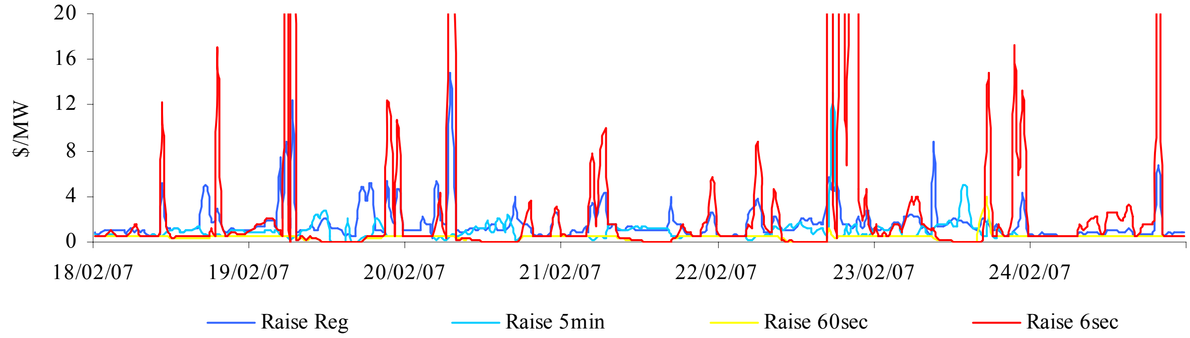


Figure 67: prices for lower services

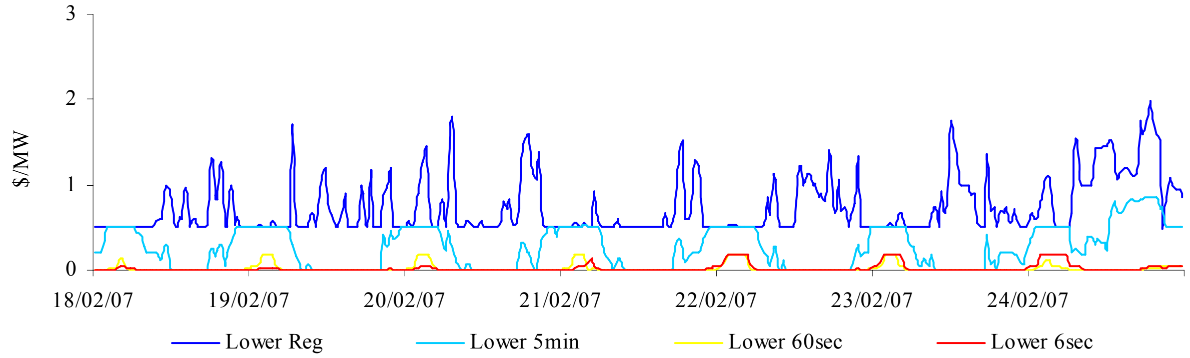
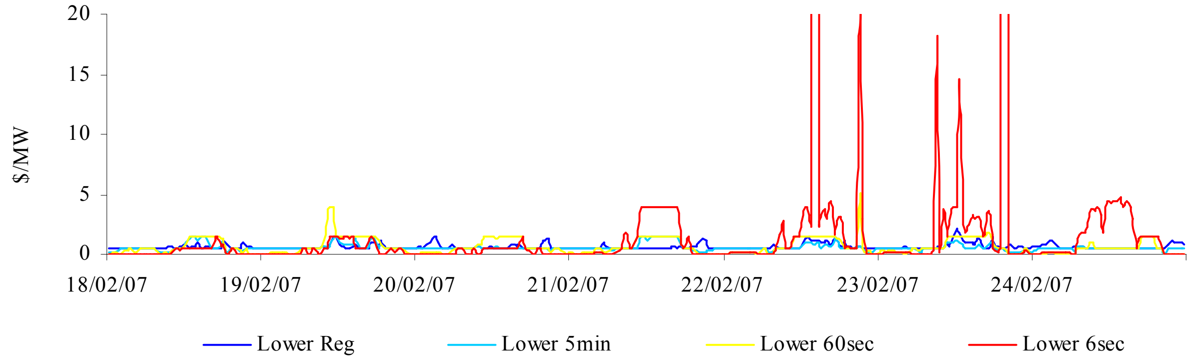


Figure 67A: prices for lower services – Tasmania



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

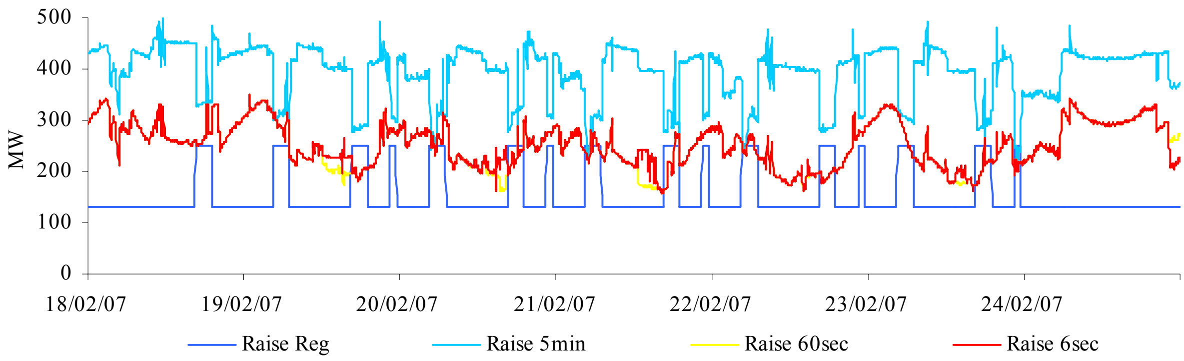


Figure 68A: raise requirements – Tasmania

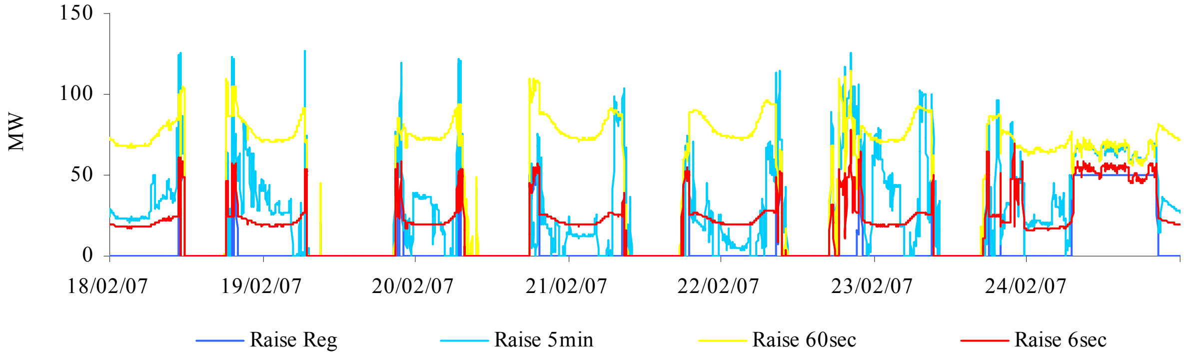


Figure 69: lower requirements

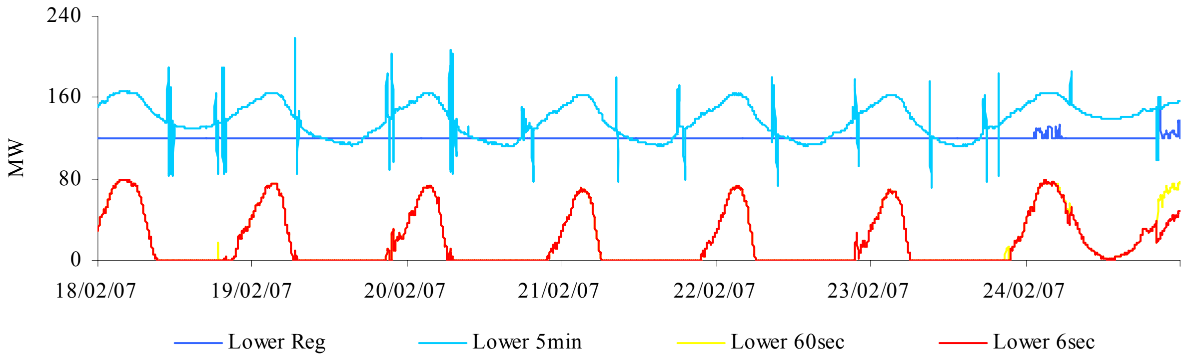
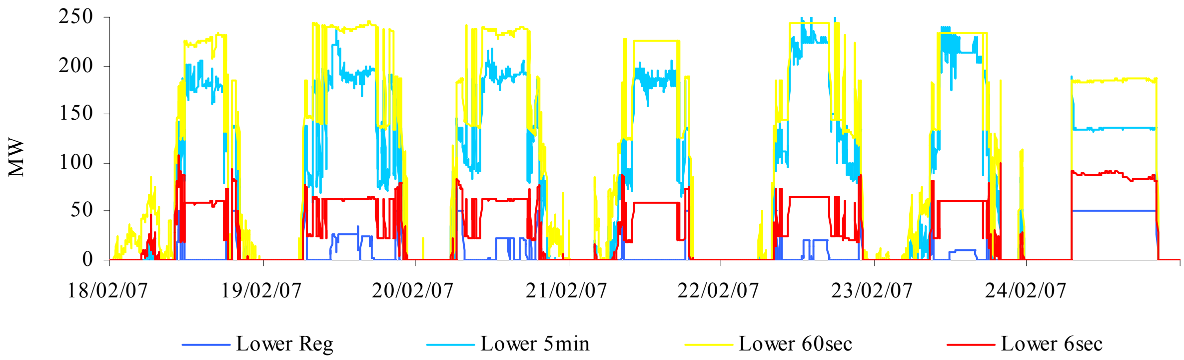


Figure 69A: lower requirements – Tasmania



Australian Energy Regulator
March 2007