Market analysis

10 – 16 SEPTEMBER 2006

Spot prices for the week averaged between $19/MWh in Queensland and $48/MWh in Tasmania.

Turnover in the energy market was $136 million. The total cost of ancillary services for the week was $396 000, or 0.3 per cent of energy market turnover.

Significant variations between actual prices and those forecast 4 and 12 hours ahead occurred in 87, or a quarter of all trading intervals. Demand forecasts produced 4 and 12 hours ahead varied from actual by more than 5 per cent in 11 per cent of all trading intervals across the market. These variations were most frequent in South Australia, occurring in almost a fifth 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

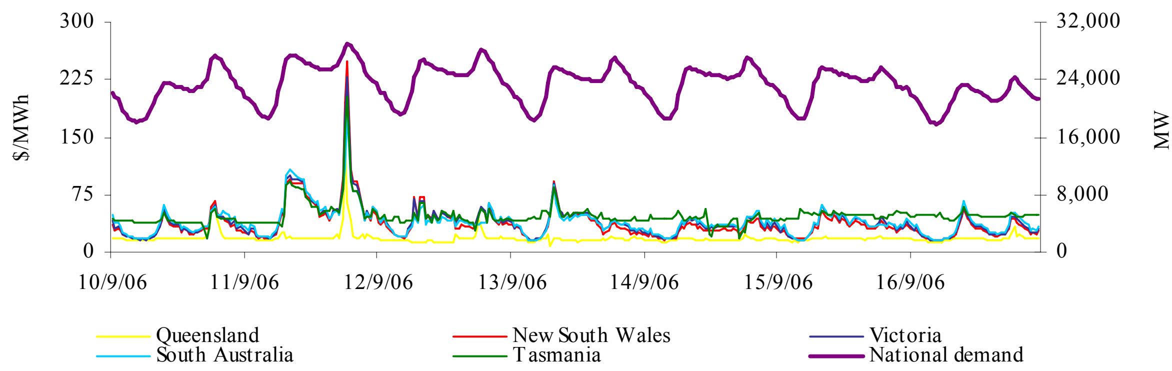


Figure 2: volume weighted average spot price for energy market ($/MWh)

	QLD	NSW	VIC	SA	TAS
Last week	19	39	40	41	48
Previous week	22	30	32	35	37
Same quarter last year	22	29	30	34	100
Financial year 2005 - 06	31	43	36	44	59
% change from previous week*	▼14%	▲30%	▲27%	▲16%	▲29%
% change from same quarter last year**	▼13%	▲35%	▲35%	▲20%	▼52%

*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

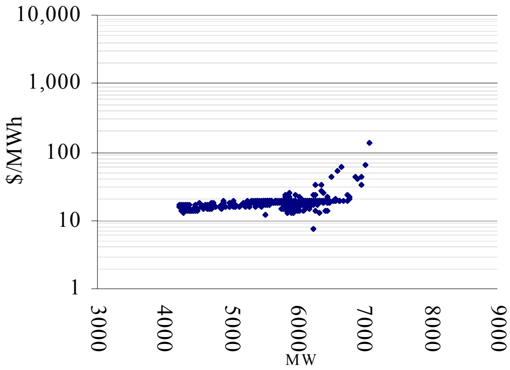


Figure 4: New South Wales

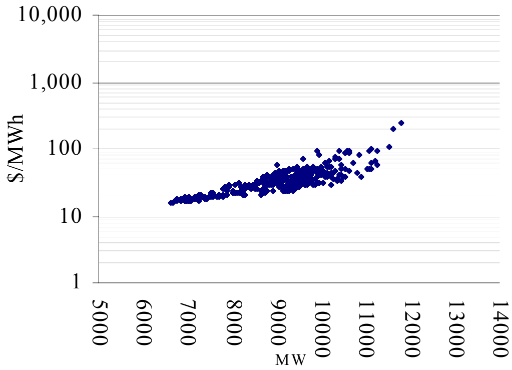


Figure 5: Victoria

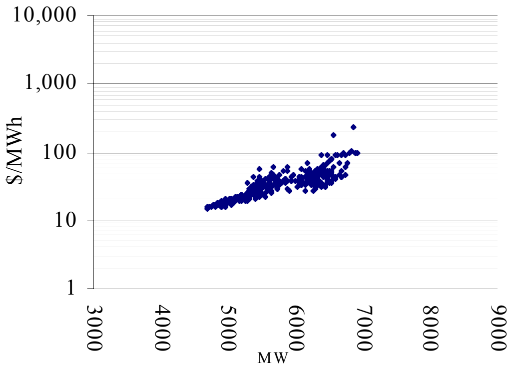


Figure 6: South Australia

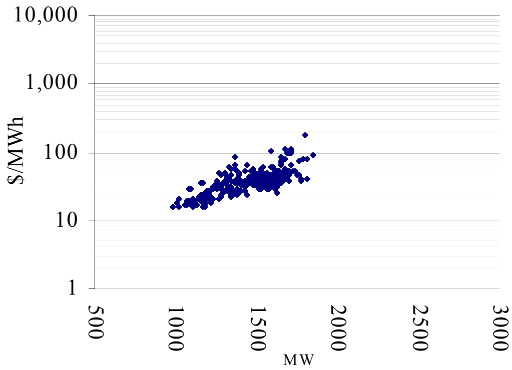
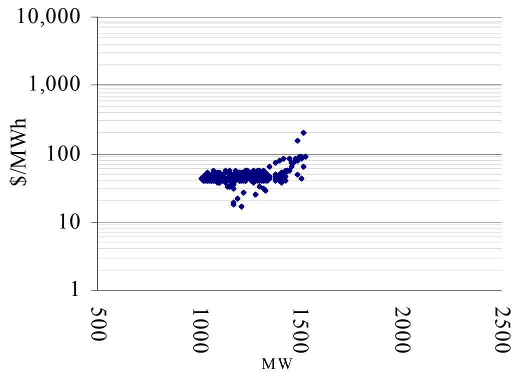


Figure 7: Tasmania



The maximum spot prices for the week ranged from $137/MWh in Queensland to $248/MWh in New South Wales, all occurring over the evening peak on Monday. 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	0.27	0.95	0.78	0.71	0.38
Previous week	0.46	0.50	0.45	0.49	0.35
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

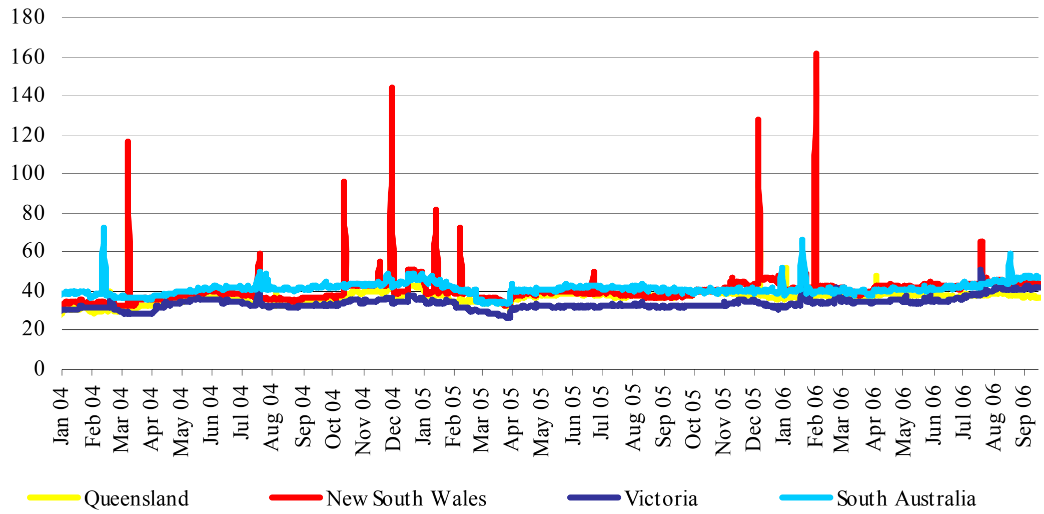
Figure 9 sets out the d-cyphaTrade wholesale electricity price index (WEPI)* for each region throughout the week excluding Tasmania. Figure 10 sets out the WEPI since 1 January 2004.

Figure 9: d-cyphaTrade WEPI for the week

	Monday	Tuesday	Wednesday	Thursday	Friday
Queensland	37.41	36.82	36.77	36.91	37.12
New South Wales	45.02	44.89	44.28	44.50	43.85
Victoria	41.51	41.71	41.97	42.38	42.32
South Australia	47.45	46.85	46.64	47.62	46.70

* 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

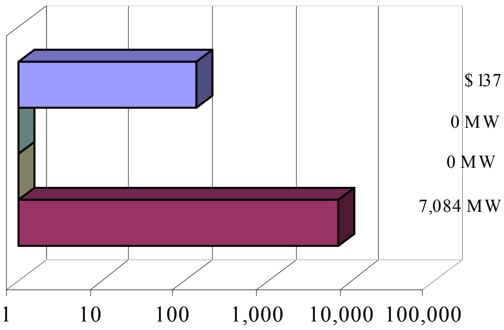


Figure 12: New South Wales

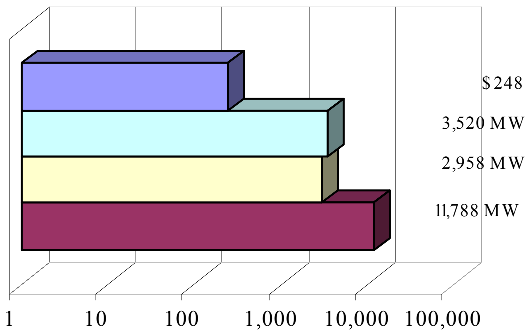


Figure 13: Victoria

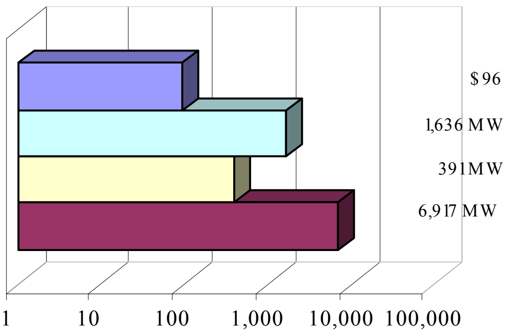


Figure 14: South Australia

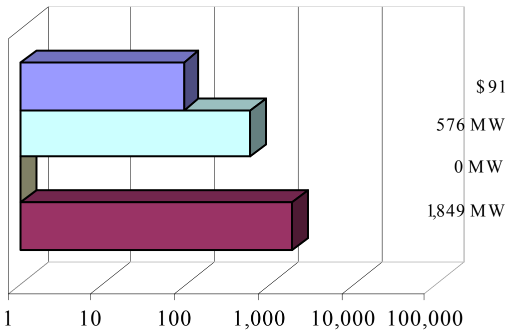
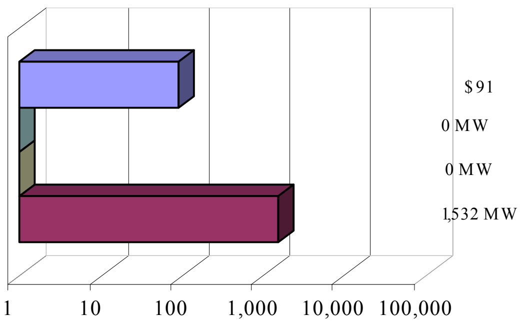


Figure 15: Tasmania



Price variations

There were 87 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

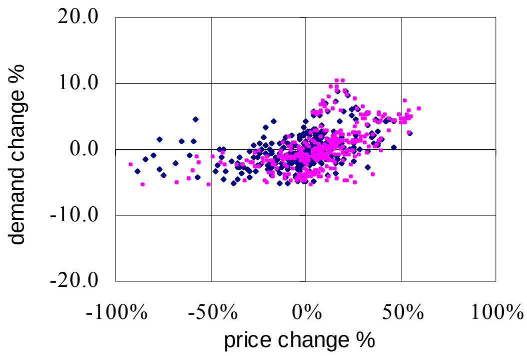


Figure 18: Victoria

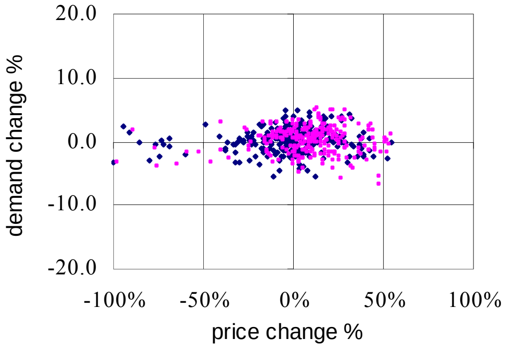


Figure 19: South Australia

Figure 20: Tasmania

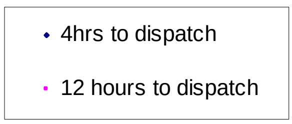
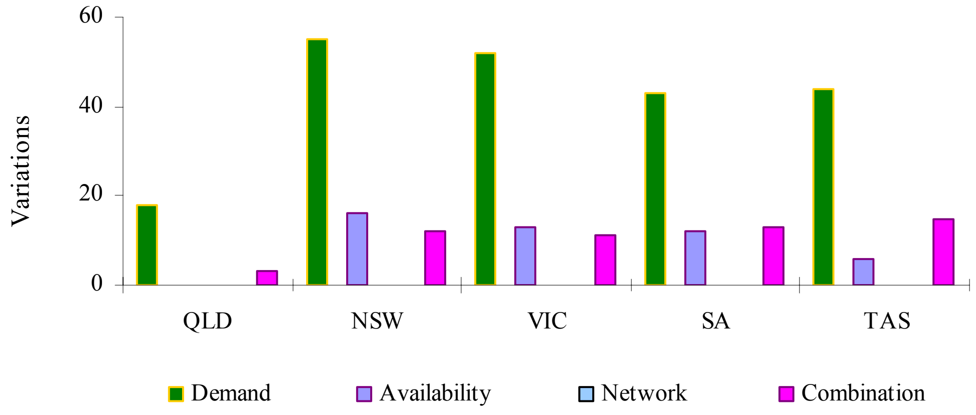


Figure 21 summarises the number and most probable reason for variations between forecast and actual prices.

Figure 21: reasons for variations between forecast and actual prices



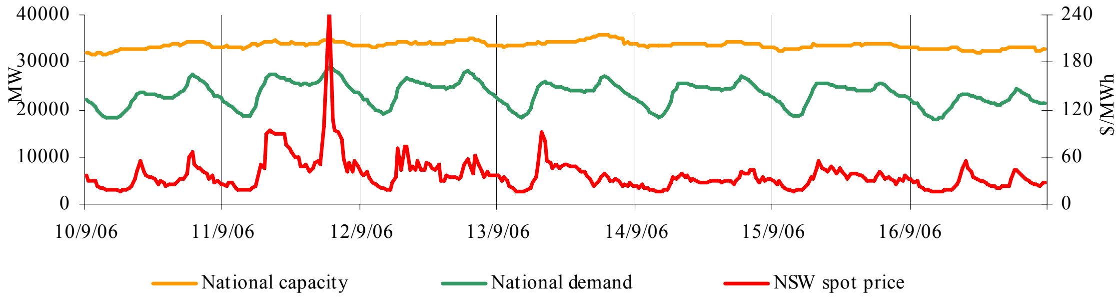
Price and demand

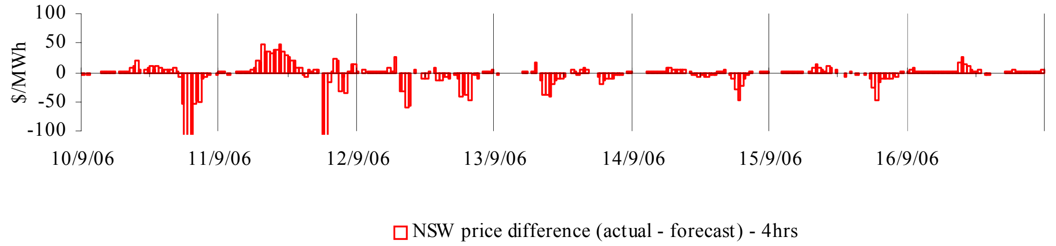
Figures 22 – 56 set out details of spot prices and demand on a national and regional basis. They include the actual spot price, actual demand and variation from forecasts made 4 and 12 hours ahead of dispatch.

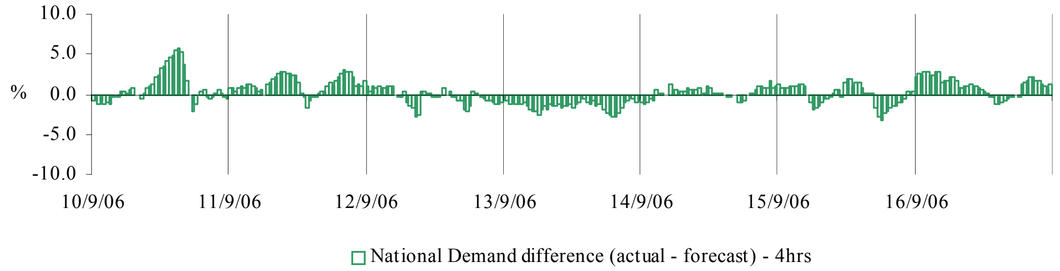
The regions within the national market are regularly aligned, with conditions in one region reflected across all others. The national market outcomes section highlights pricing events that occurred when spot prices were generally aligned across all regions of the national electricity market – the New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

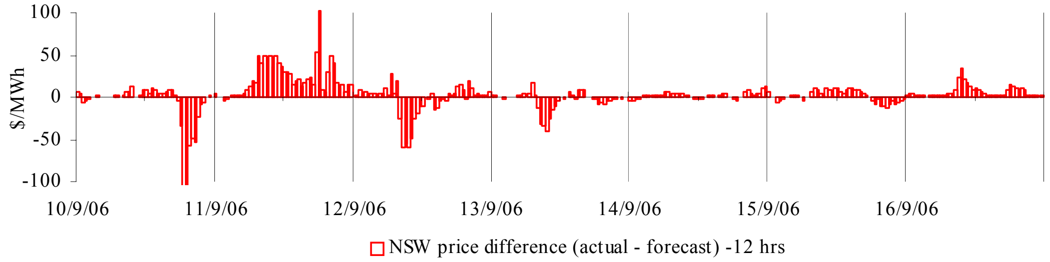
On a regional basis the differences between the maximum temperature and the temperature forecast at around 6.00 pm the day before are also included. In each section, the occurrences of all prices for the week greater than three times the average have been presented. The price forecast is compared to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

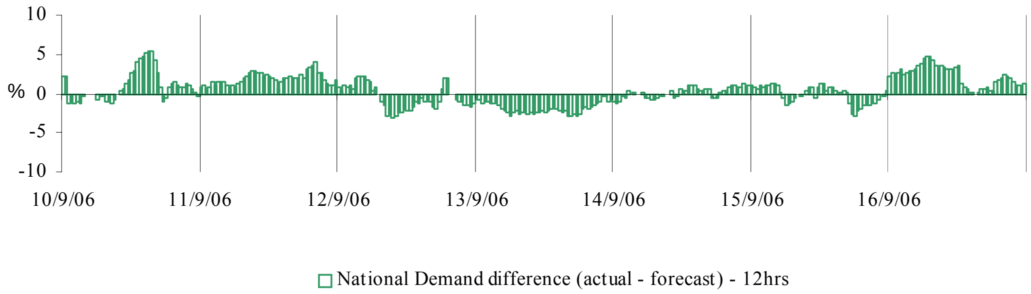
Figures 22-26: National market outcomes











National market outcomes

There were two occasions where spot prices were generally aligned nationally and the New South Wales price[1] was greater than three times the New South Wales weekly average price of $39/MWh.

Monday, 11 September

6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	195.51	666.33	93.86
Demand (MW)	28546	28288	27970
Available capacity (MW)	34515	34639	35071
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	247.86	665.95	238.65
Demand (MW)	29047	28545	28149
Available capacity (MW)	34548	34634	35078

Conditions at the time saw national demand up to 500 MW higher than forecast four hours ahead.

At 10.35 am, International Power's Hazelwood unit 2 in Victoria tripped from 195 MW. The rebid reason given was "Unit outage". All of this capacity was priced at less than zero. This followed the unplanned shutdown of unit 7 at around 7.30 am. A number of rebids over the course of the afternoon delayed the return of this unit until after the evening peak, removing 220 MW of capacity priced at less than $20/MWh from the market. The rebid reasons given included "Plant conditions – change to sync time". At 2.47 pm, 120 MW of capacity at Pelican Point in South Australia was rebid from prices above $9000/MWh to less than $100/MWh. The rebid reason given was "Portfolio management-redistribution of MWs across units".

Two units at TRUEnergy's Yallourn power station in Victoria tripped over the course of the morning, reducing the capacity of the station by around 700 MW. The rebid reasons given were "Unit outage::Zero availability" and "Unit outage::ERTS and runup" respectively. Both units were expected to return to service quickly, however, a rebid at 1.14 pm delayed the return of both units until after the evening peak. The rebid reasons given were "Unit outages::ERTS update". All of this capacity was priced at less than $10/MWh. At 1.38 pm, TRUEnergy committed 200 MW of additional capacity at Torrens Island in South Australia. This capacity was priced at less than zero. The rebid reason given was "Plant conditions-portfolio multi forced outages".

Earlier, at 11.20 am, Stanwell Corporation in Queensland rebid 380 MW of capacity at Stanwell from prices of less than $30/MWh to above $250/MWh. The rebid reason given was "Change in market conditions".

At 1.27 pm, AGL rebid 160 MW of capacity at Somerton in Victoria from prices above $9000/MWh to zero, committing the unit. The rebid reason given was "Predispatch – forecast price change::sustain". A further rebid at 3.30 pm shifted 100 MW of capacity at Hallett in South Australia from prices above $9000/MWh to zero. The rebid reason given was "Predispatch-forecast price change::increase".

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

At 1.32 pm, Braemar in Queensland committed 155 MW. All of this capacity was priced at less than $20/MWh. The rebid reason given was “Manage gas constraints”.

At 1.56 pm, LYMMCO rebid 405 MW of capacity at Loy Yang A in Victoria from prices below $20/MWh to above $4100/MWh. The rebid reason given was “Material change in PD of 13:33”.

From 2 pm, Ecogen in Victoria rebid almost 450 MW of capacity into prices of less than $100/MWh. Most of this capacity was previously priced above $9000/MWh. The rebid reasons given included “Band adjustment due to notice of contractual change”.

At 3.23 pm, Hydro Tasmania reduced the availability of Gordon by 129 MW. The rebid reason given was “Outage extended” although the unit was operating at full output prior to the rebid. All of this capacity was priced at less than $50/MWh.

Over two rebids from 6.13 pm Snowy Hydro rebid 200 MW of capacity at Murray and Upper Tumut from prices above $225/MWh to below $95/MWh. The rebid reason given for both rebids was “M:Prices higher than exptd:Bandshift down”.

There was no other significant rebidding.

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

There were three occasions where the spot price in Queensland was greater than three times the weekly average price of $19/MWh. Two 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.

Sunday, 10 September

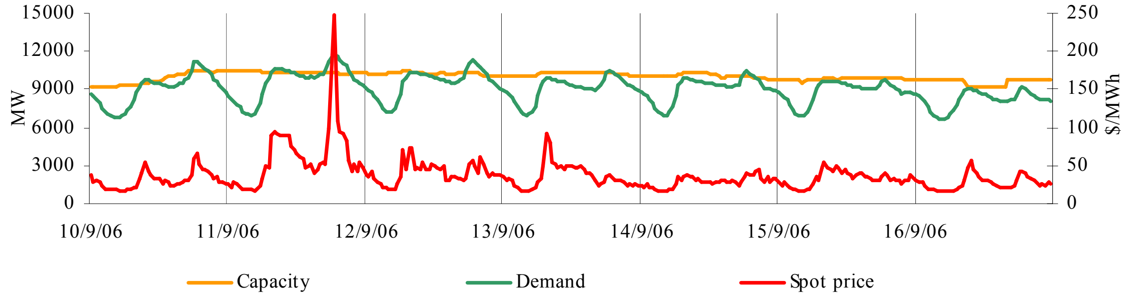
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	58.69	18.67	18.67
Demand (MW)	6652	6311	6281
Available capacity (MW)	9026	9031	9031

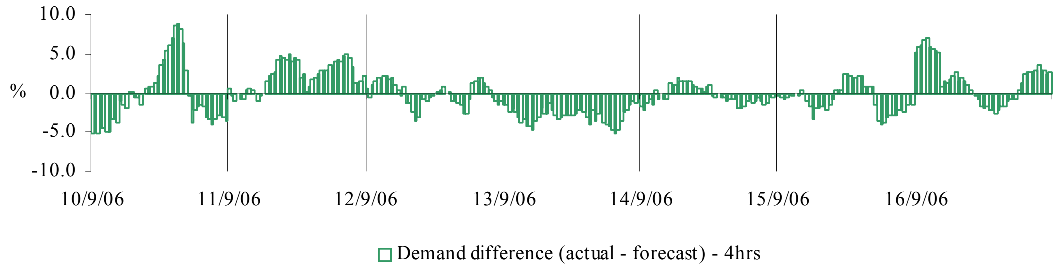
Conditions at the time saw demand in Queensland 340 MW higher than forecast with prices aligned across the mainland.

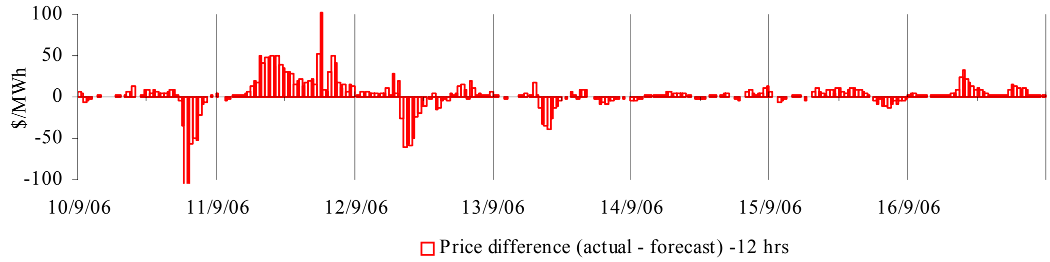
Actual flows south across the Queensland to New South Wales interconnector were unconstrained but around 150 MW higher than forecast.

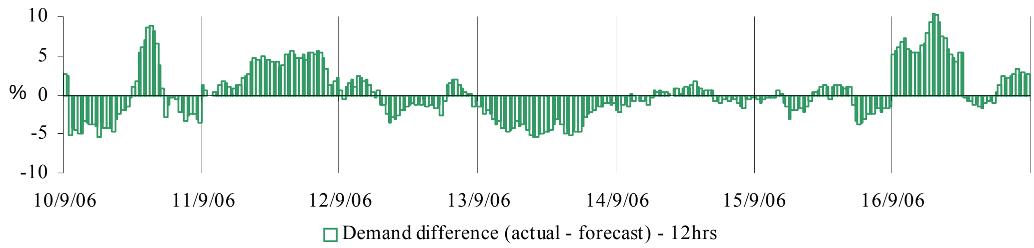
There was no significant rebidding.

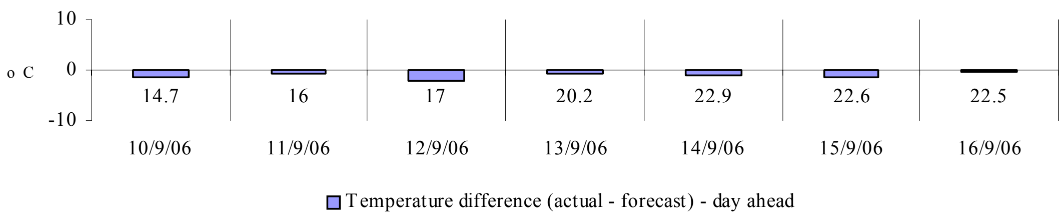
Figures 33-38 New South Wales actual spot price, demand and forecast differences





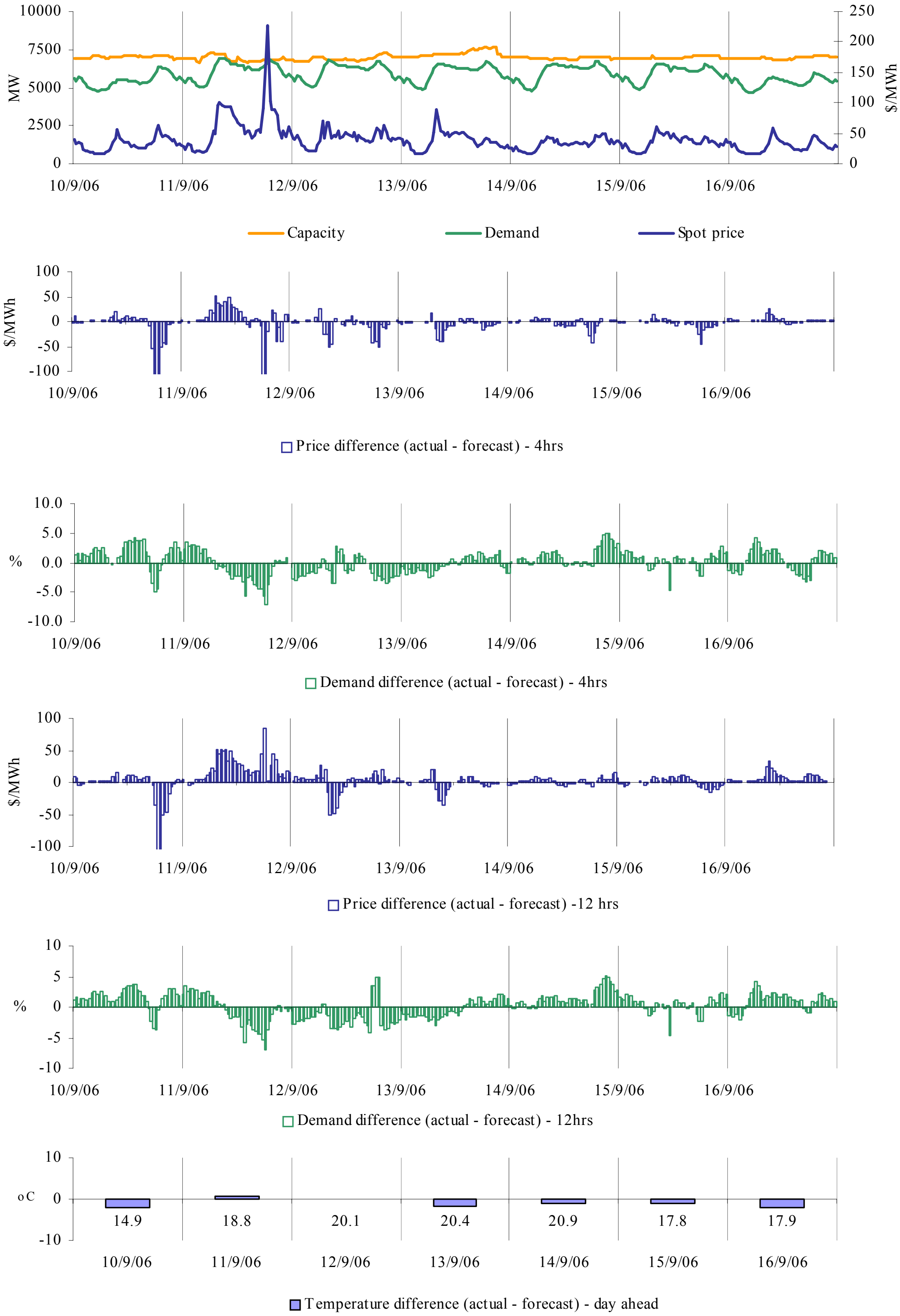






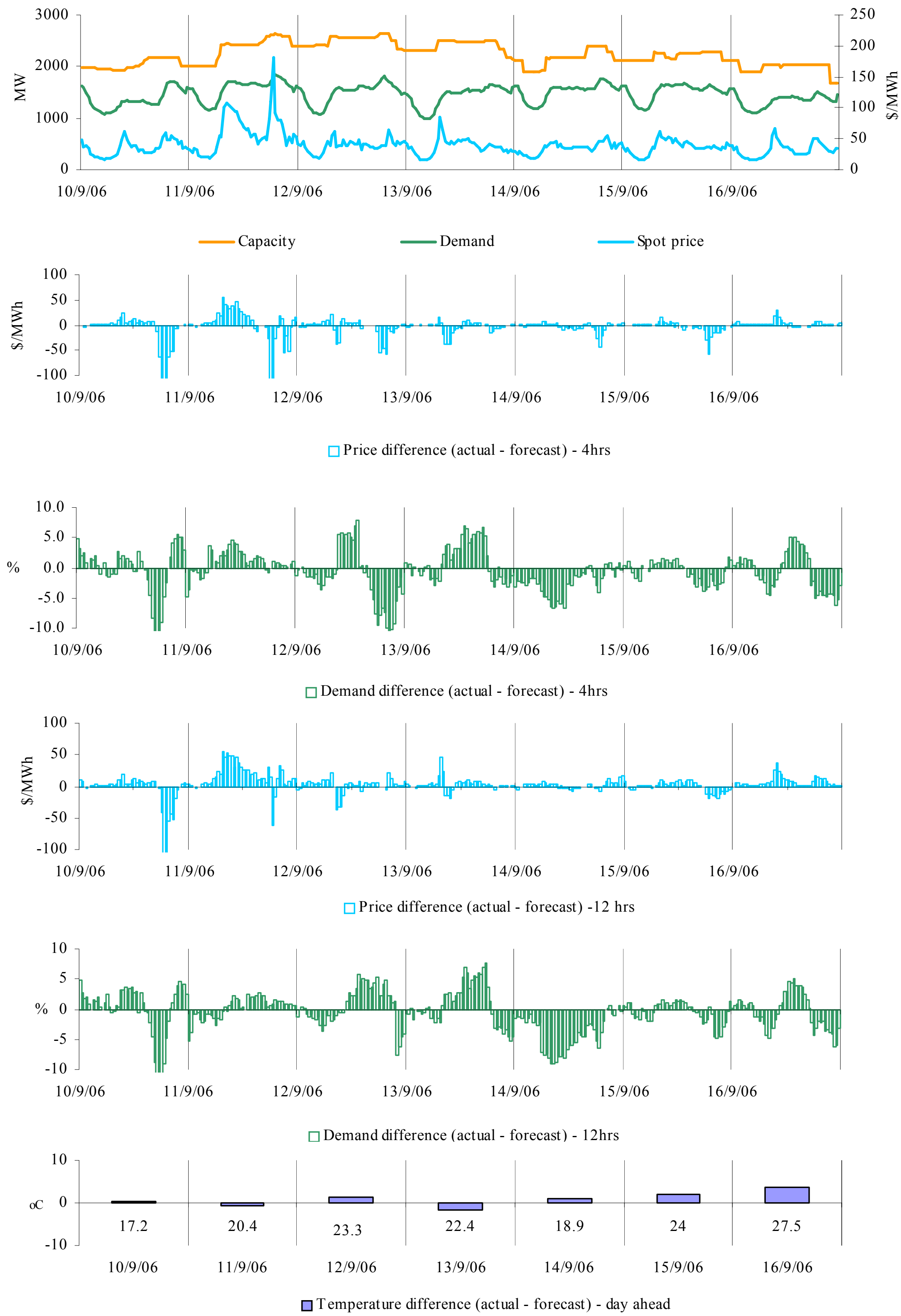
There were three occasions where the spot price in New South Wales was greater than three times the weekly average price of $39/MWh. At the time, prices were aligned across the market. The circumstances of these events are detailed under the national market outcomes section.

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



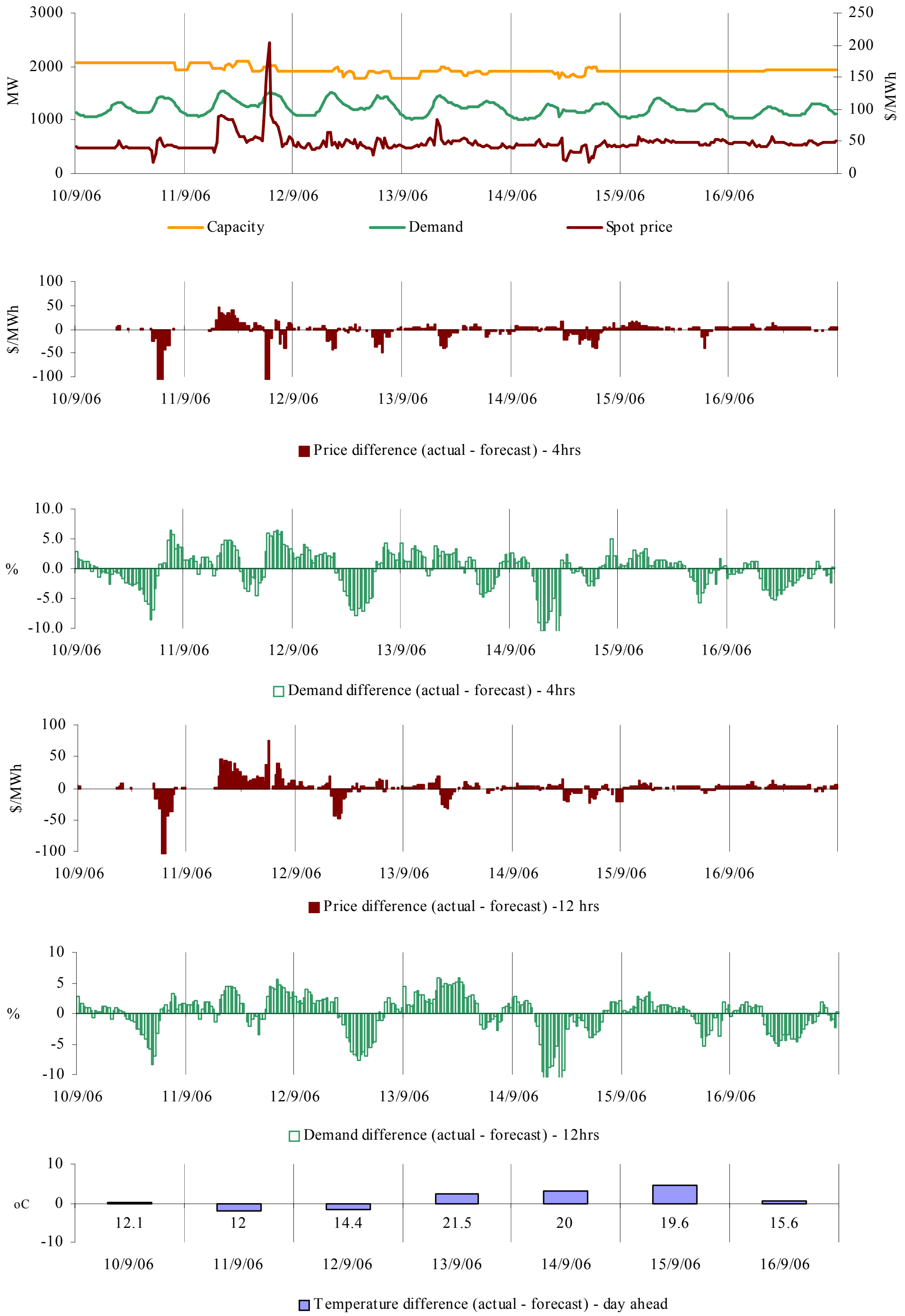
There were two occasions where the spot price in Victoria was greater than three times the weekly average price of $40/MWh. At the time, prices were aligned across the market. The circumstances of these events are detailed under the national market outcomes section.

__Figures 45-50: South Australia actual spot price, demand and forecast differences__



There was one occasion where the spot price in South Australia was greater than three times the weekly average price of $41/MWh. At the time, prices were aligned across the market. The circumstances of this event are detailed under the national market outcomes section.

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 $48/MWh. At the time, prices were aligned across the market. The circumstances of these events 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

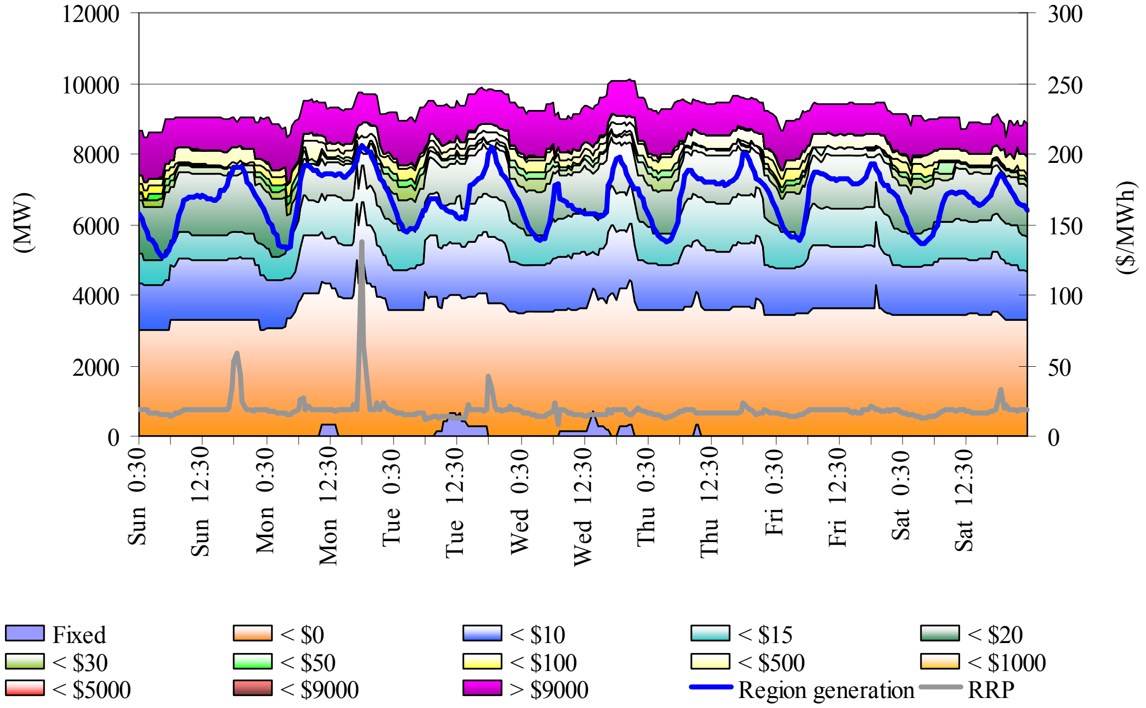


Figure 58: New South Wales closing bid prices, dispatched generation and spot price

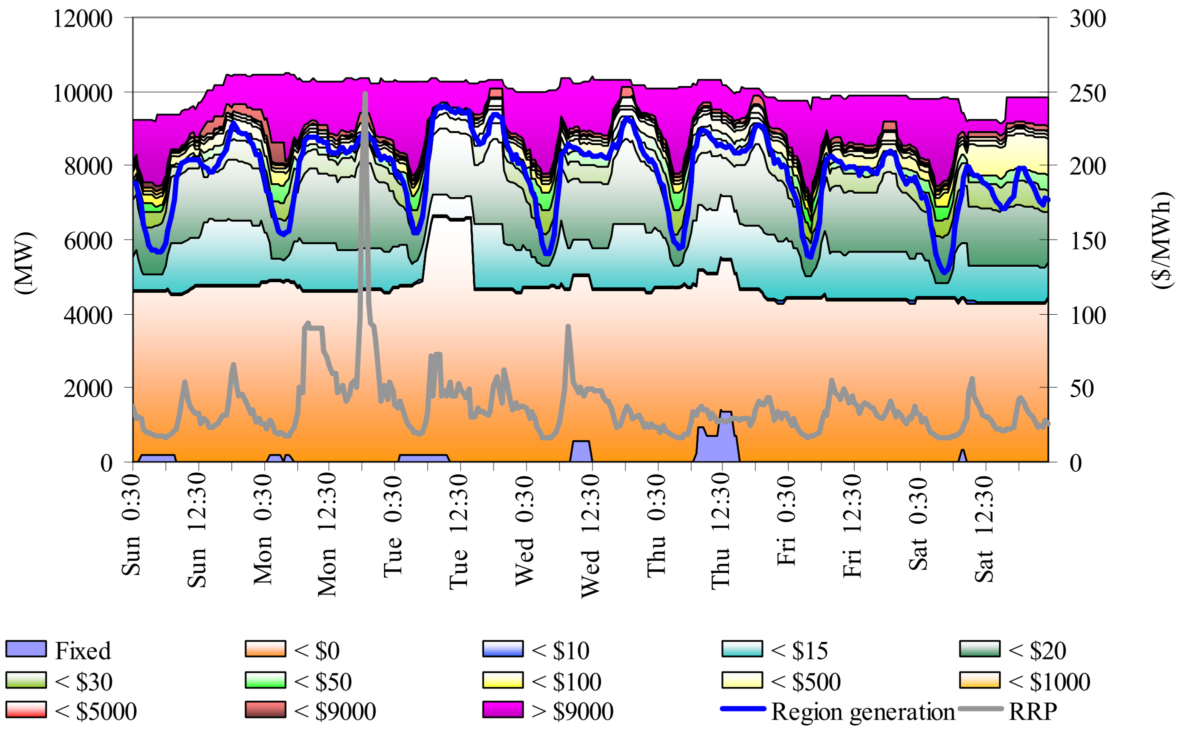


Figure 59: Victoria closing bid prices, dispatched generation and spot price

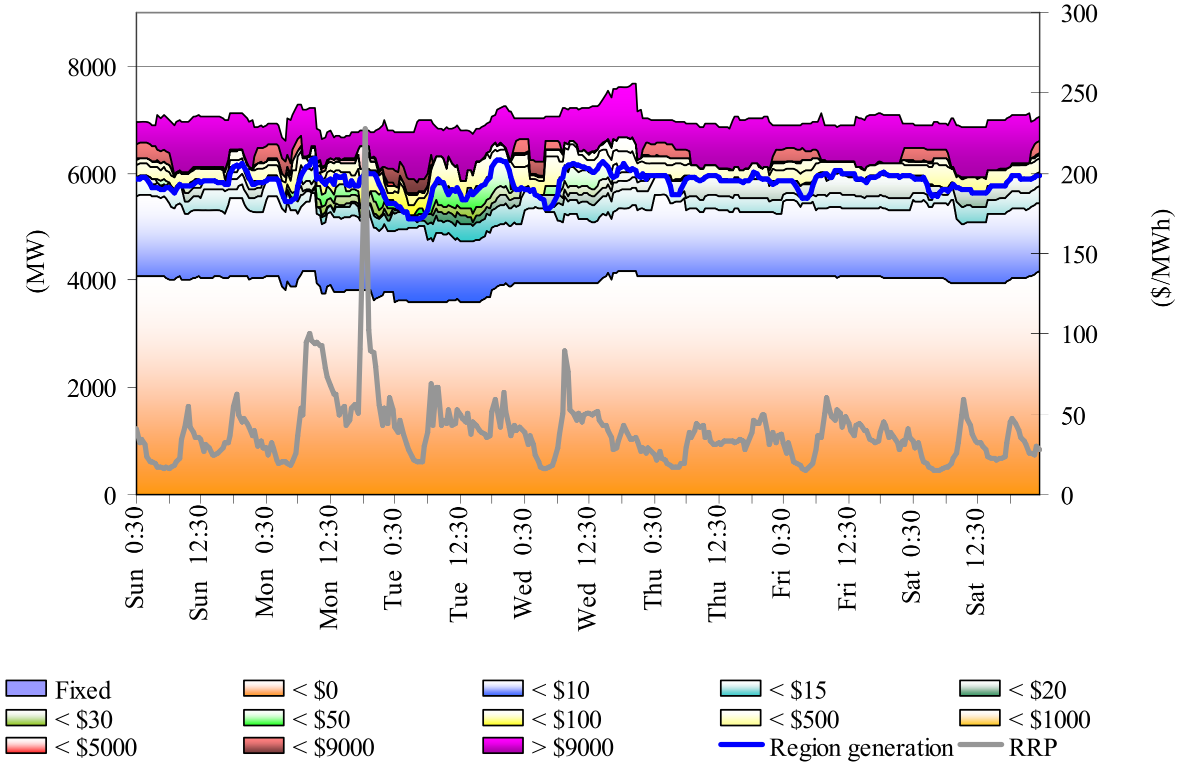


Figure 60: South Australia closing bid prices, dispatched generation and spot price

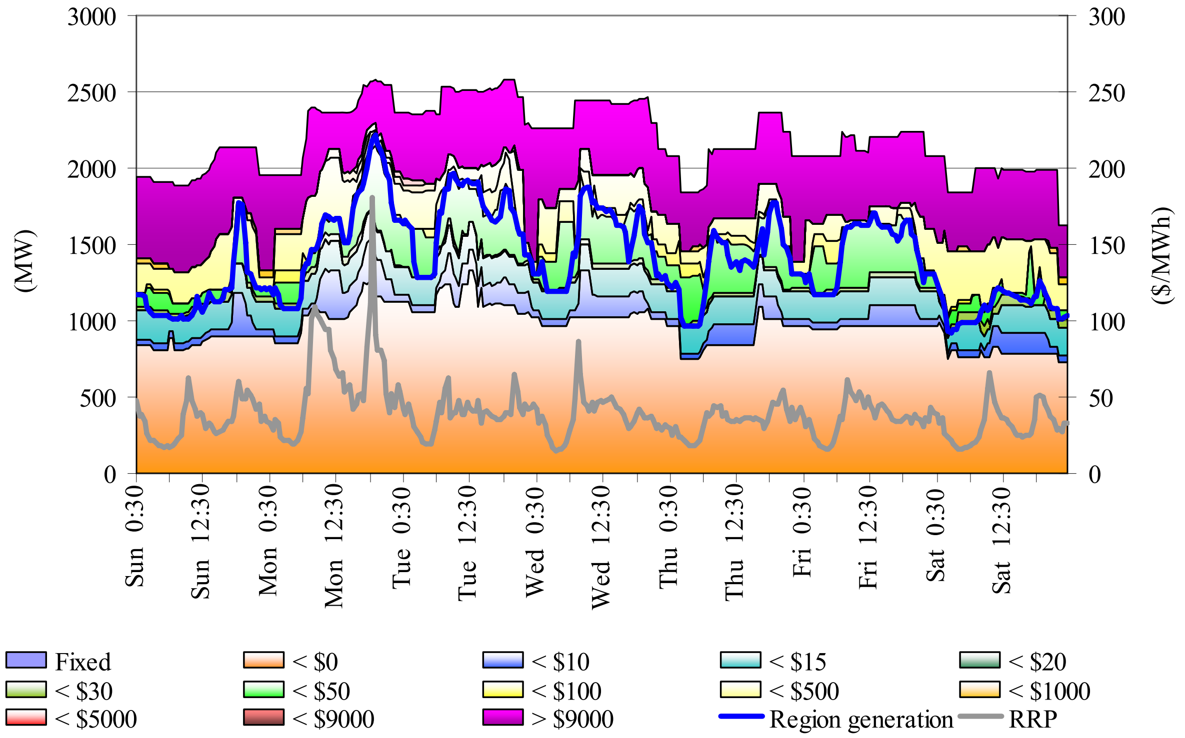
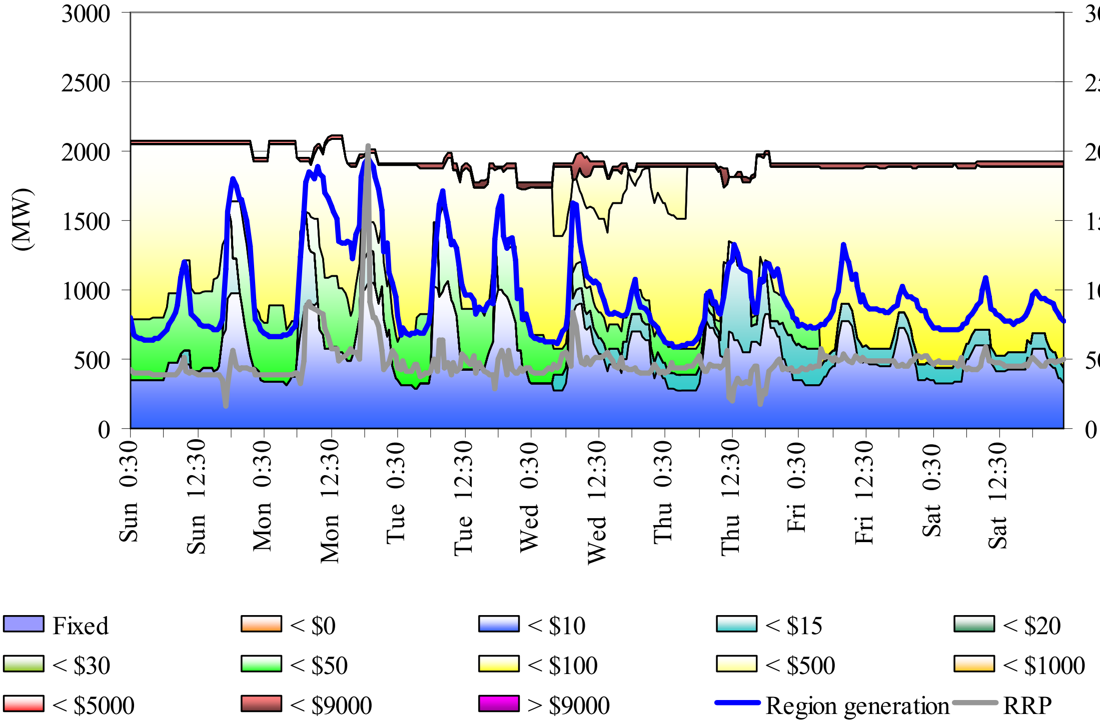


Figure 61: Tasmania closing bid prices, dispatched generation and spot price



Ancillary service market

The total cost of ancillary services on the mainland for the week was $305 000 or 0.2 per cent of the energy market. Locally sourced lower services 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 ($/MW)	2.48	0.27	1.13	2.60	1.82	0.67	1.43	1.05
Previous week ($/MW)	1.46	0.15	0.69	2.95	1.31	0.59	1.22	1.03
Last quarter ($/MW)	1.76	0.73	1.15	1.54	0.39	2.28	5.00	1.93
Market Cost ($1000s)	$107	$10	$67	$61	$5	$6	$33	$15
% of energy market	0.08%	0.01%	0.05%	0.05%	0.01%	0.01%	0.03%	0.01%

The total cost of ancillary services in Tasmania for the week was $92 000 or 1 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 ($/MW)	3.61	0.80	2.11	5.30	0.48	0.36	0.59	1.10
Previous week ($/MW)	4.47	0.85	2.50	2.90	0.05	0.26	0.49	1.01
Last quarter ($/MW)	4.97	0.49	2.93	3.00	12.67	0.43	0.82	0.45
Market Cost ($1000s)	$22	$11	$27	$14	$4	$4	$4	$7
% of energy market	0.22%	0.11%	0.27%	0.14%	0.04%	0.04%	0.04%	0.07%

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

Figure 64: daily frequency control ancillary service cost

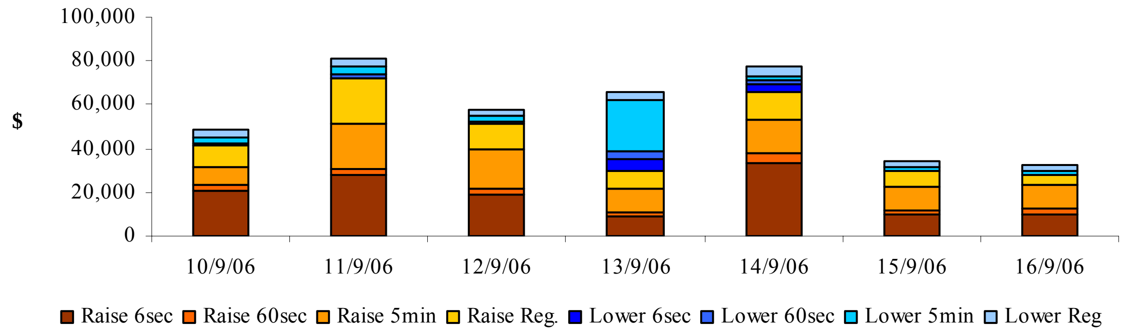
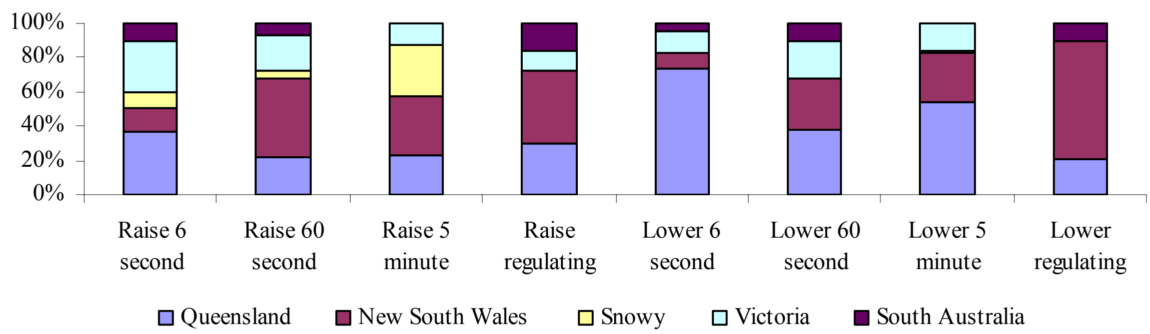


Figure 65 shows the contribution, on a percentage basis, that frequency control ancillary service providers are utilised (in each mainland region) to satisfy the total requirement for each service.

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

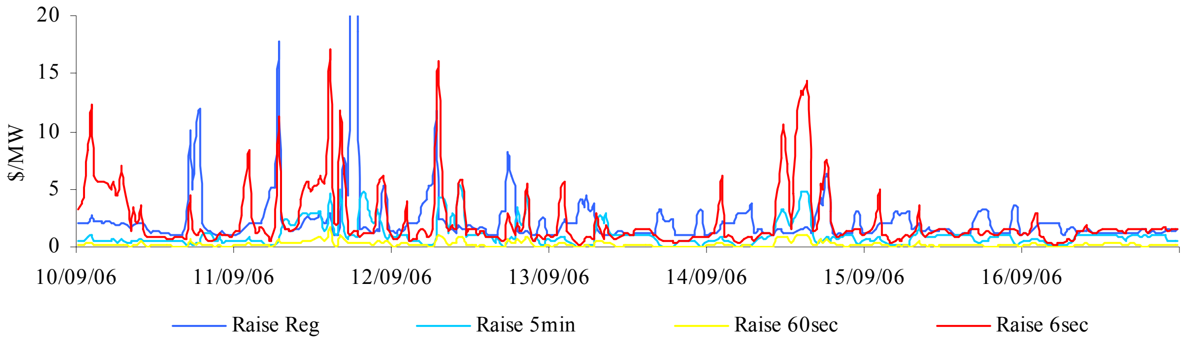


Figure 66A: prices for raise services – Tasmania

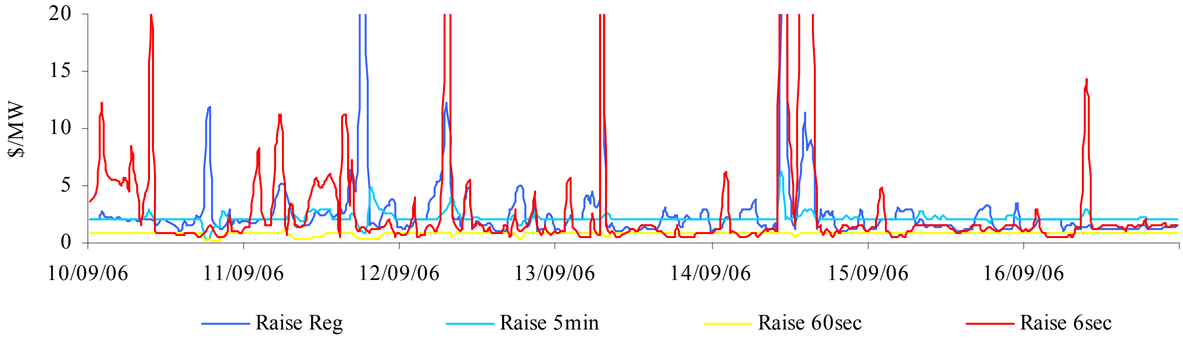


Figure 67: prices for lower services

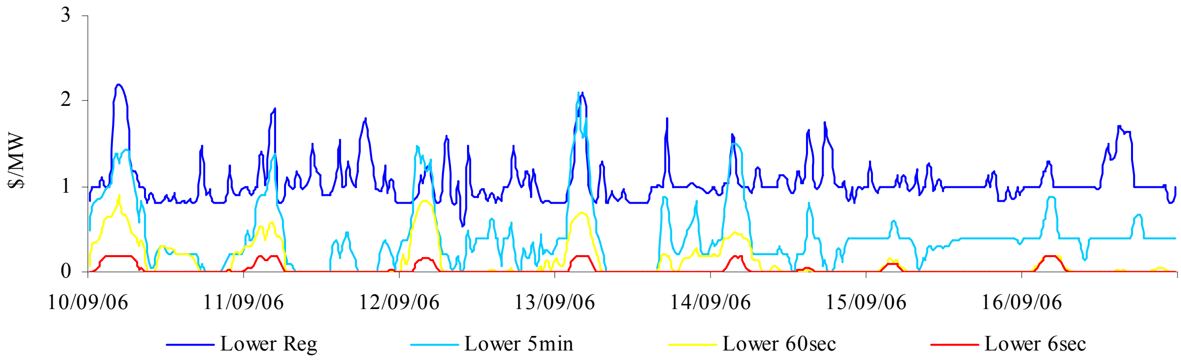
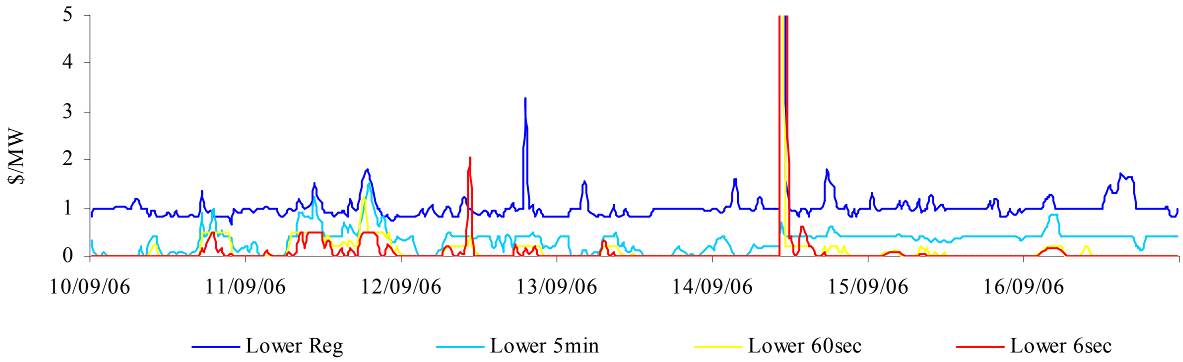


Figure 67A: prices for lower services – Tasmania



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

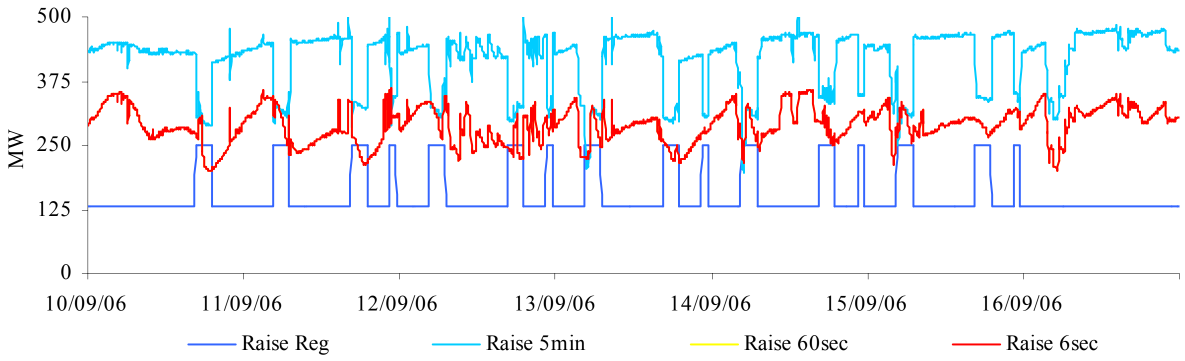


Figure 68A: raise requirements – Tasmania

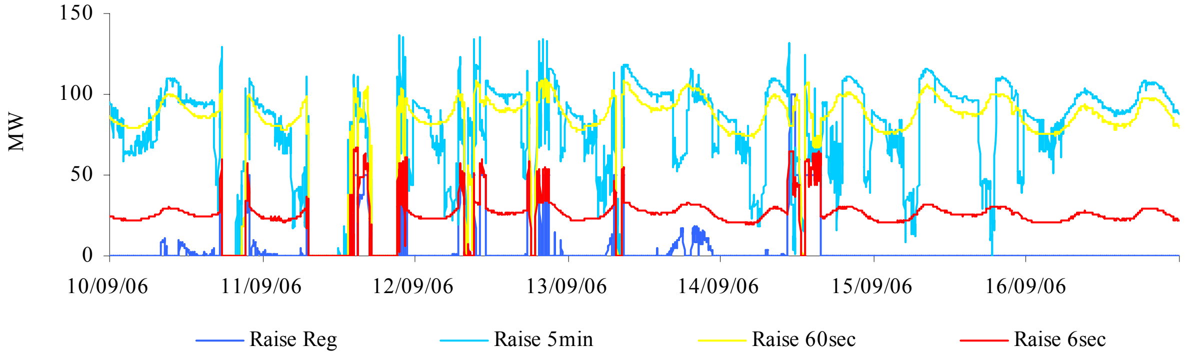


Figure 69: lower requirements

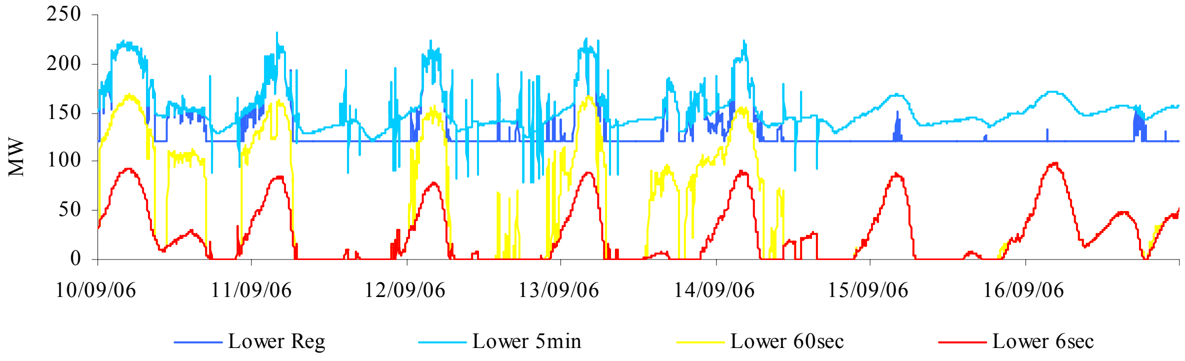
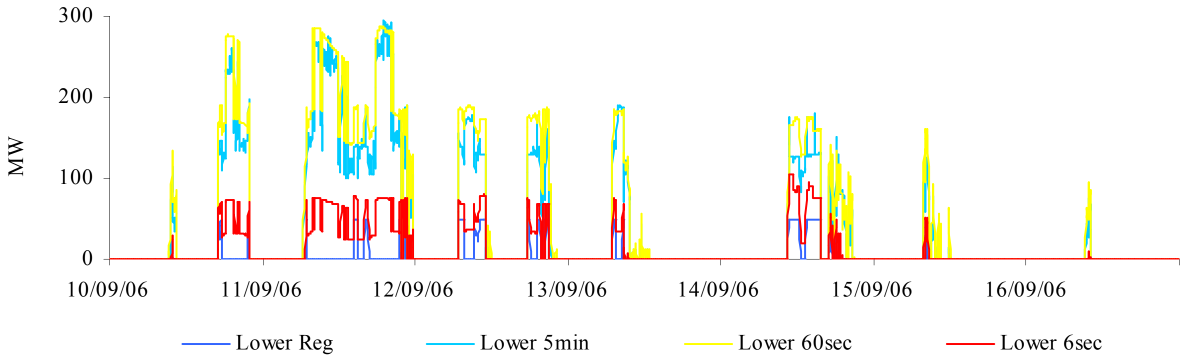


Figure 69A: lower requirements – Tasmania



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