Market analysis

AUSTRALIAN ENERGY REGULATOR

11 – 17 SEPTEMBER 2005

Spot prices for the week averaged $33/MWh in Queensland and $43/MWh in New South Wales, Victoria and South Australia. These prices represented an increase of around half compared to the previous week. A reduction in capacity available at low prices in Victoria contributed to this increase. In Tasmania average spot prices were around the same as the previous week at $63/MWh.

Turnover in the energy market for the mainland was $146 million, with a total cost of ancillary services for the week of around $500,000 or 0.3 per cent of turnover of the mainland. In Tasmania turnover was $13 million, with ancillary services totaling $350,000 or three per cent of turnover. The price for raise 6 second services reached $10,000/MW between 3.30pm and 3.45pm on Sunday when there was insufficient availability of these services as a result of lightning.

Demand forecasts produced 4 and 12 hours ahead varied from actual by more than 5 per cent in a quarter of all trading intervals across the market. In South Australia and Tasmania demand errors occurred in around half and a third of all trading intervals respectively, on the same basis. Significant variations between forecast and actual prices occurred in 72 or 21 per cent of all trading intervals.

Energy prices

Figure 1 compares the volume weighted average price with the averages for the previous week, the same quarter last year and for the financial year up to the end of the week. Figure 2 sets out national demand and spot prices in each region for each trading interval. Figure 3 compares the weekly price volatility index with the averages for the previous week and the same quarter last year.

Figure 1: volume weighted average spot price for energy market ($/MWh)

	QLD	NSW	VIC	SA	TAS
Last week	33	43	43	43	63
Previous week	24	27	26	28	66
Same quarter last year	27	31	28	36	-
Financial year to date	22	29	30	35	105
% change from previous week	▲39%	▲59%	▲65%	▲53%	▼5%
% change from same quarter last year	▲25%	▲36%	▲53%	▲19%	-
% change from last financial year	▼18%	▼11%	▲5%	▼8%	-

Figure 2: national demand and spot prices

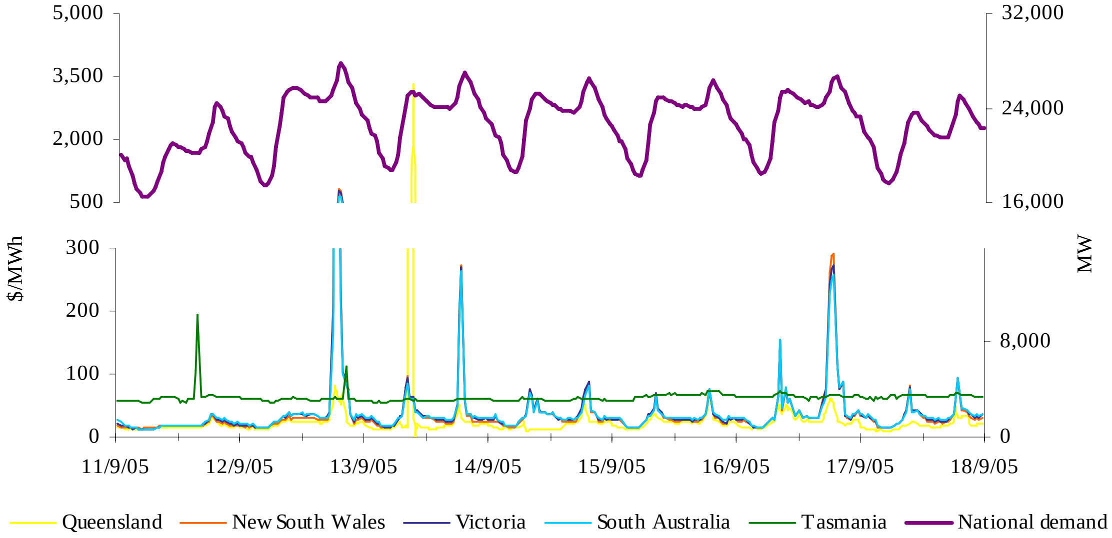


Figure 3: volatility index during peak periods

	QLD	NSW	VIC	SA	TAS
Last week	1.12	1.65	1.39	1.19	0.17
Previous week	0.62	0.57	0.45	0.31	0.10
Same quarter last year	0.64	0.74	0.71	0.56	-

Figures 4 to 8 show the weekly correlation between spot price and demand.

Figure 4: Queensland

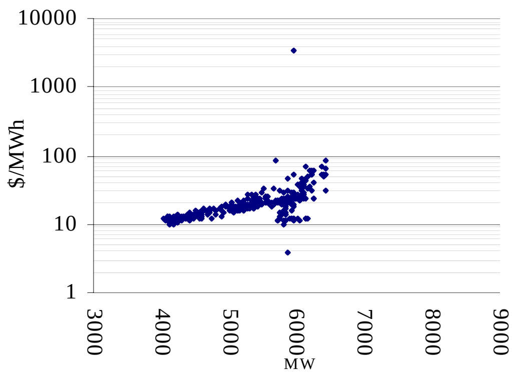


Figure 5: New South Wales

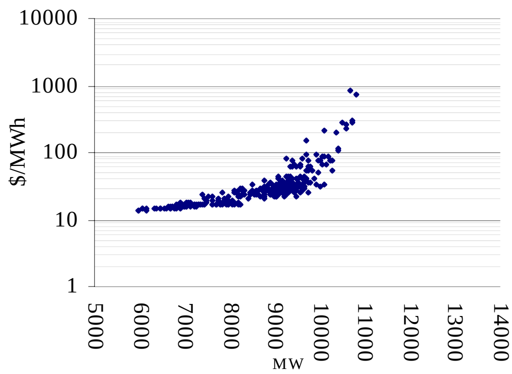


Figure 6: Victoria

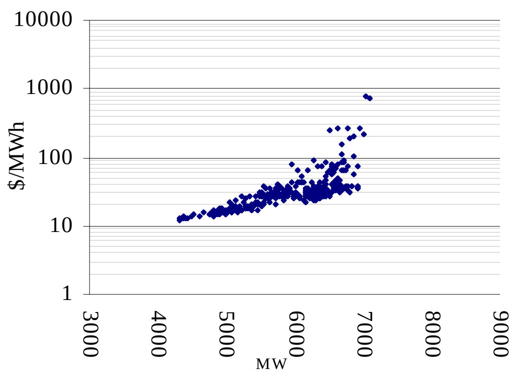


Figure 7: South Australia

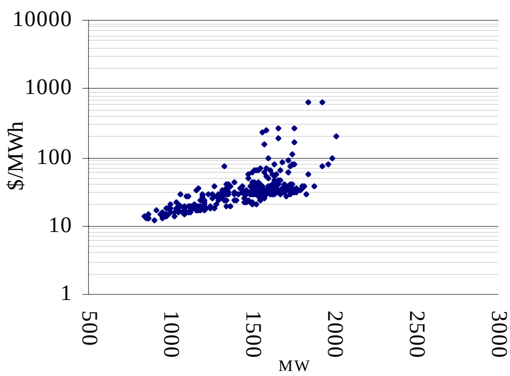
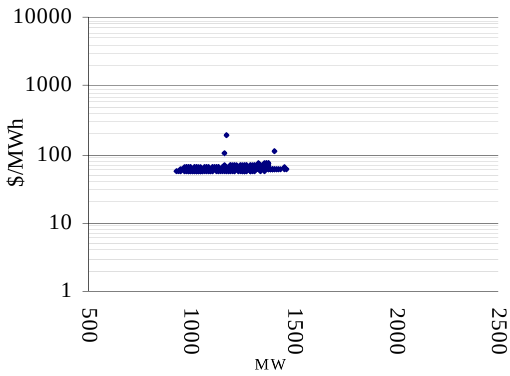


Figure 8: Tasmania



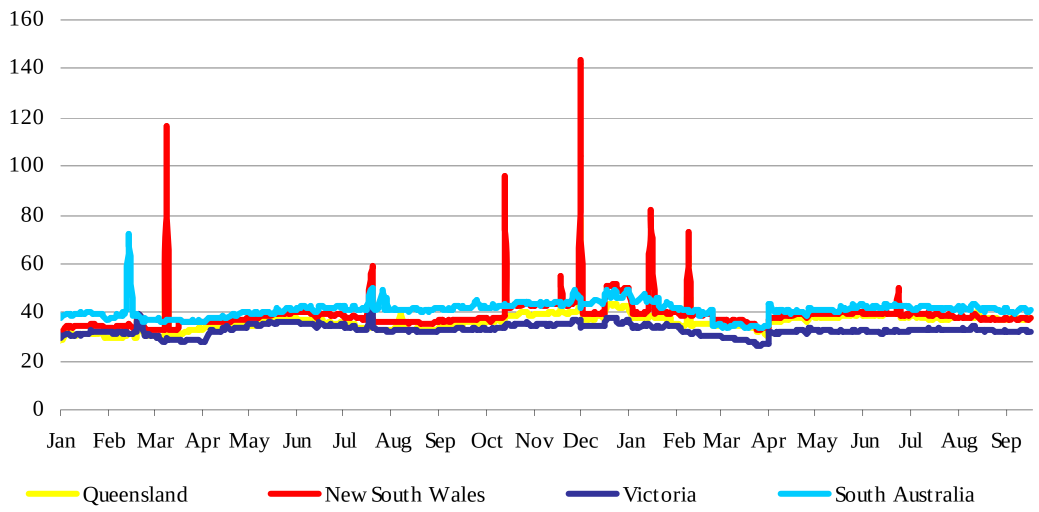
The maximum spot prices for the week were $3,332/MWh in Queensland occurring on Tuesday morning, $829/MWh in New South Wales, $768/MWh in Victoria and $650/MWh in South Australia, all occurring at 6.30pm on Monday. In Tasmania, the spot price reached $195/MWh at 4pm on Sunday.

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	37.26	37.53	37.51	37.51	37.46
New South Wales	37.94	37.88	37.34	37.28	37.92
Victoria	32.99	32.57	32.27	32.38	32.36
South Australia	41.50	40.60	39.93	40.12	40.95

Figure 10: d-cyphaTrade WEPI



Reserve

There were no low reserve conditions forecast throughout the week. Figures 11 to 14 show spot price, net imports and limits at the time of weekly maximum demand.

Figures 11 to 14: spot price, net import and limit at time of weekly maximum demand

Figure 11: Queensland

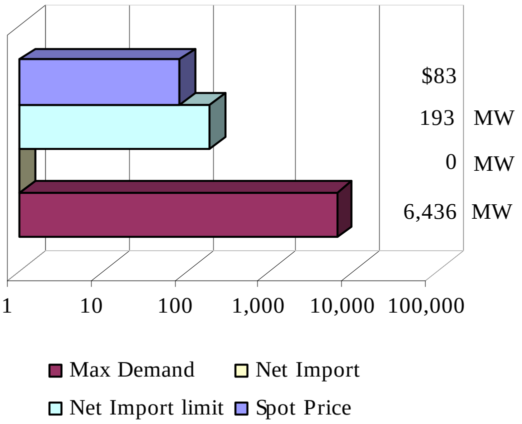


Figure 12: New South Wales

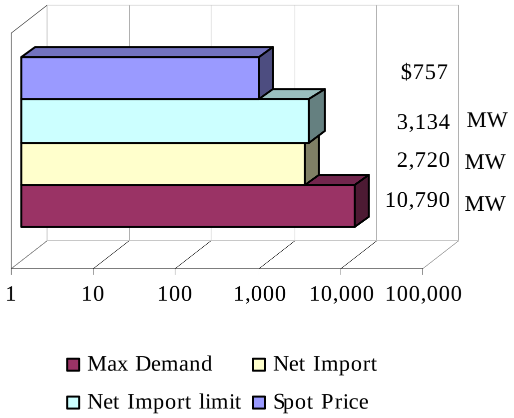


Figure 13: Victoria

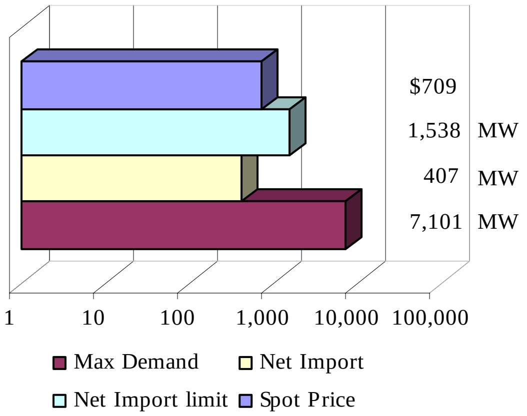
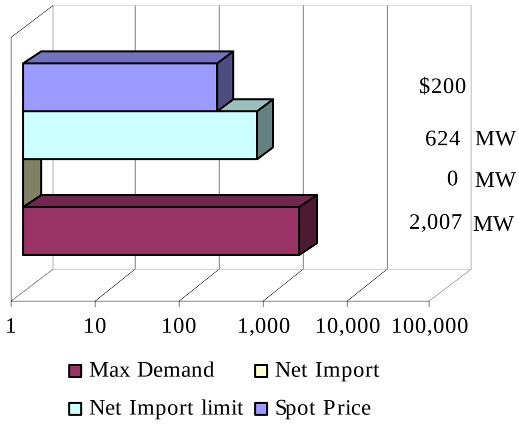


Figure 14: South Australia



In Tasmania, the demand reached a maximum of 1,466MW at 7pm on Monday. The spot price at the time was $62/MWh.

Price variations

There were 72 trading intervals where significant variations between forecast and actual prices occurred, calculated 4 and 12 hours ahead of despatch. Figures 15 to 18 set out the correlation between the actual price and demand and those forecast. The information is presented in terms of the percentage difference from actual. Price differences beyond 200 per cent have been capped.

Figure 15: Queensland

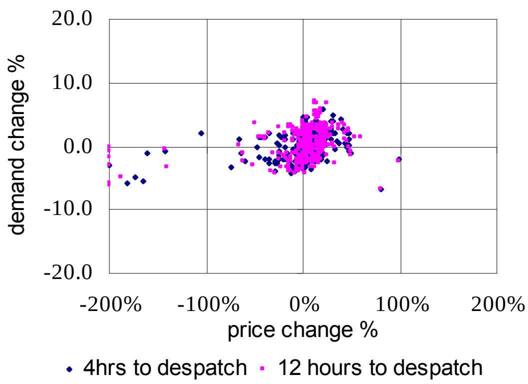


Figure 16: New South Wales

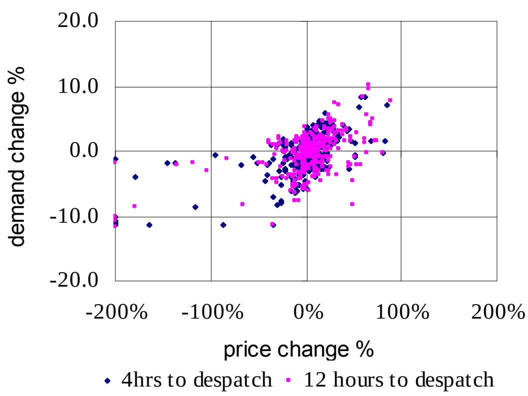


Figure 17: Victoria

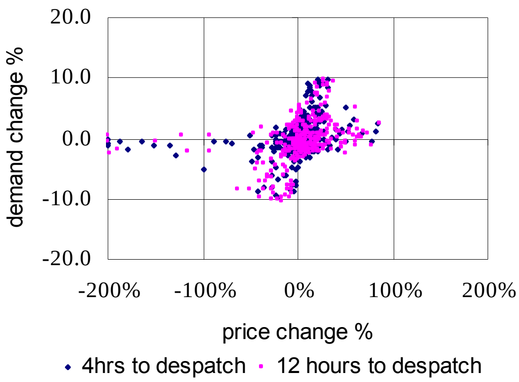


Figure 18: South Australia

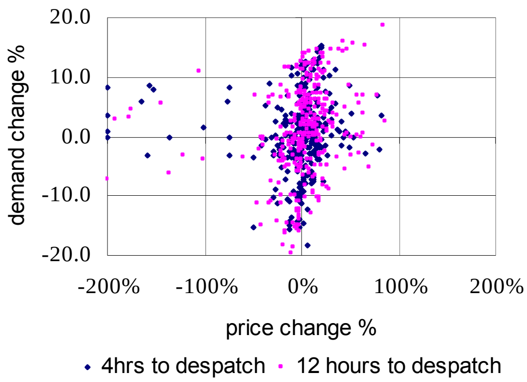


Figure 19: Tasmania

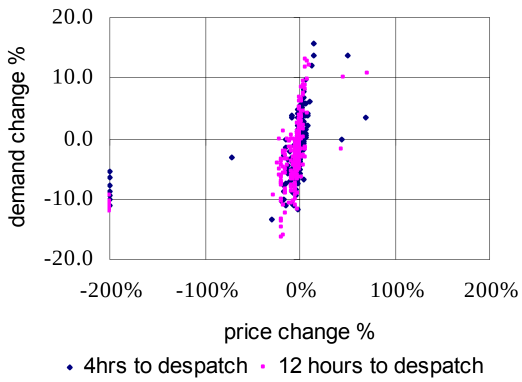
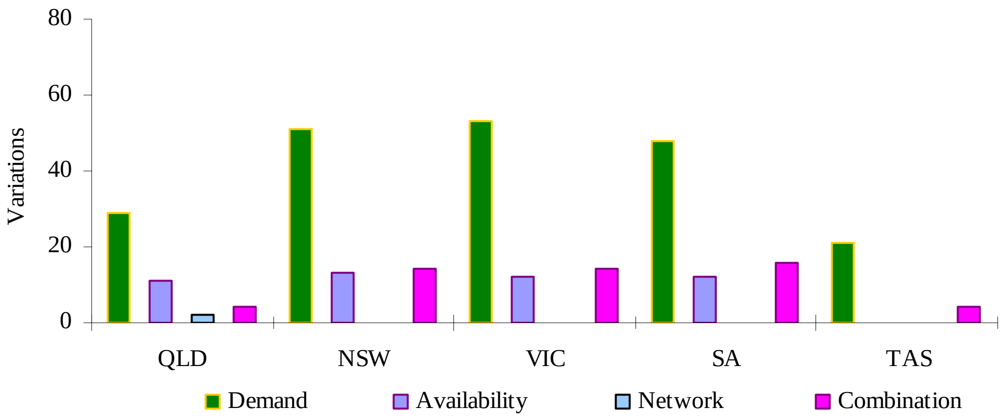


Figure 20 summarises the number and most probable reason for variations between forecast and actual prices.

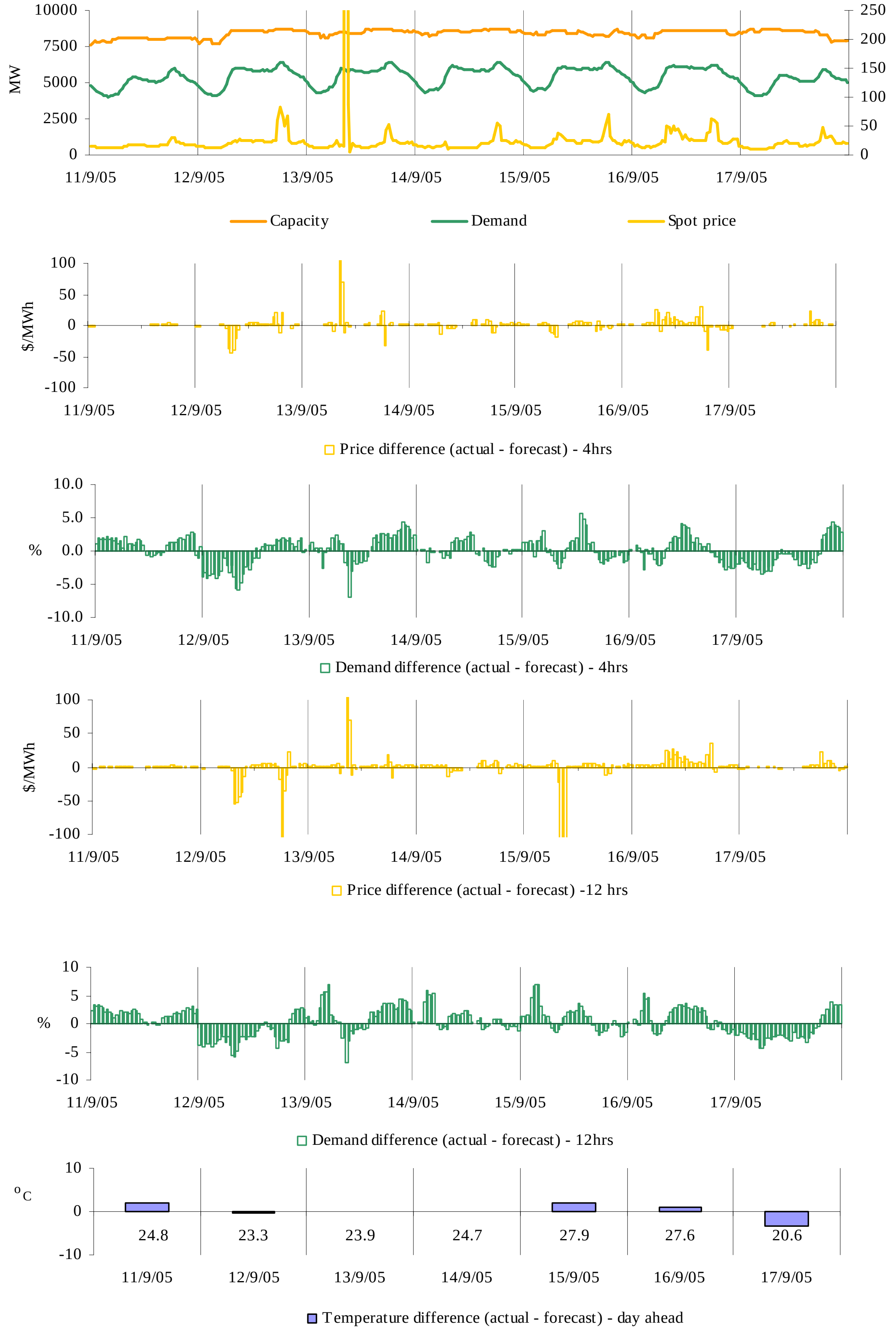
Figure 20: reasons for variations between forecast and actual prices



Price and demand

Figures 21 - 50 set out details of spot prices and demand on a regional basis. They include the actual spot price and demand outcomes and difference graphs both four and twelve hours ahead of despatch on a daily basis. The differences between the maximum temperature and the temperature forecast at around 6.00 pm the day before are also included. Figures 51 - 55 set out, for each region, the extent of capacity offered into the market within a series of price thresholds. Actual price and generation despatched in a region are overlaid.

Figures 21-26: Queensland actual spot price, demand and forecast differences



There was one occasion in Queensland where the spot price was greater than three times the weekly average price of $33/MWh. This occurred at Sunday and at 9am on Tuesday.

Tuesday, 13 September

9:00 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3332.43	16.45	16.45
Demand (MW)	5,948	6,072	6,090
Available capacity (MW)	8,474	8,644	8,648

Violated constraints led to unusual dispatch outcomes between 8.30am and 9.30am with inconsistent limits on the New South Wales to Queensland interconnector reported during this period.

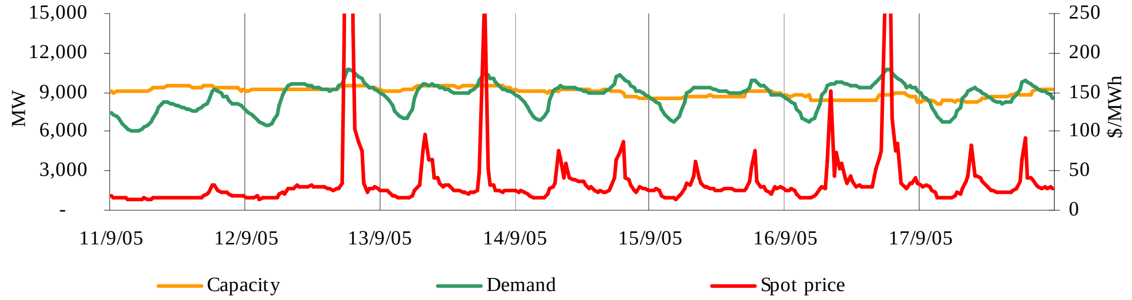
At 8.40am, constraints were invoked to manage system security in Queensland. Shortly after, at 8.50am, the limits were constricted further, resulting in infeasible dispatch outcomes for both, generation in Queensland and flows on the New South Wales to Queensland interconnector. Flows north were reduce by 850MW, and subsequently forced south, whilst generation was constrained off by 200MW.

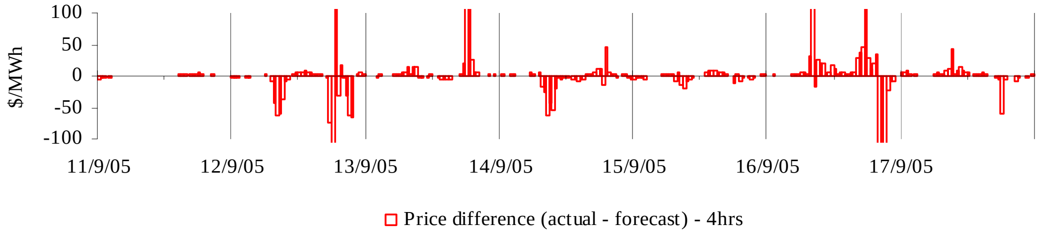
Rebids by Enertrade at 9am moved a total of 1020MW at Gladstone from prices between zero and $60/MWh to prices below zero. The rebid reason given was "Material change in market conditions::changed MW distrib". Prices went to zero for a number of despatch intervals following this rebid.

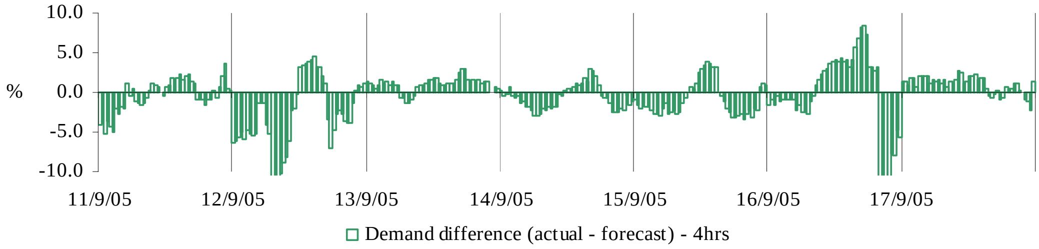
Constraints remained violated for much of the next half hour. At 9.30am, the 5 minute price spiked to $500/MWh, with intra-regional constraints again constraining off around 200MW. The constraints were removed at 9.35am.

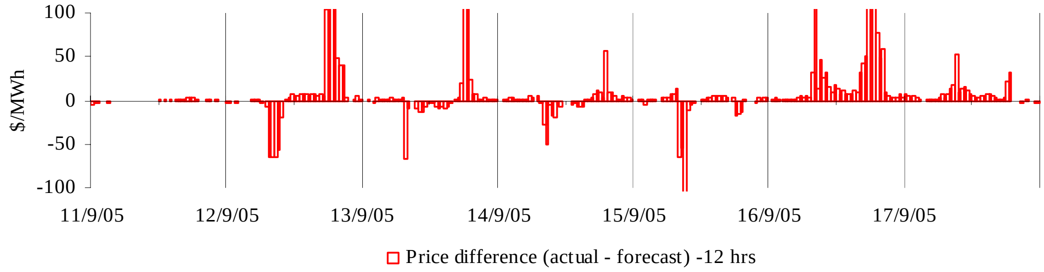
There was no other significant rebidding.

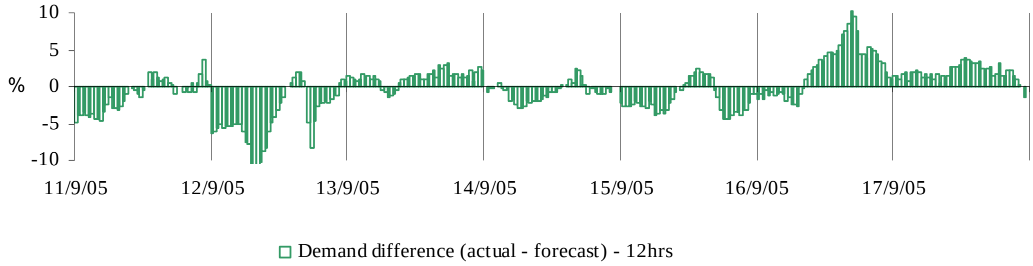
Figures 27-32 New South Wales actual spot price, demand and forecast differences

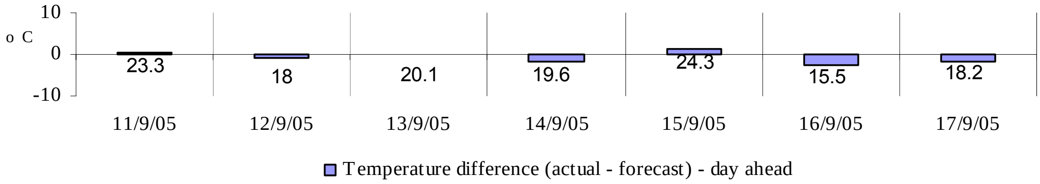












There were 10 occasions in New South Wales where the spot price was greater than three times the weekly average price of $43/MWh. These occurred over the evening peaks on Monday, Tuesday and Friday and at 8.30am on Friday.

Monday, 12 September

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	209.27	283.53	104.24
Demand (MW)	10,083	10,793	10,909
Available capacity (MW)	9,500	9,575	9,615
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	828.95	1181.06	420.35
Demand (MW)	10,666	11,169	11,164
Available capacity (MW)	9,500	9,572	9,615
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	757.19	420.16	411.82
Demand (MW)	10,790	11,076	11,072
Available capacity (MW)	9,500	9,572	9,615
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	228.90	260.00	95.01
Demand (MW)	10,585	10,822	10,821
Available capacity (MW)	9,500	9,572	9,615

Conditions at the time saw demand as much as 700MW lower than forecast four hours to dispatch. There was no capacity priced between $30/MWh and $250/MWh with around 350MW priced between $250/MWh and $6,600/MWh. Prices were aligned across the southern regions for most of this period.

At 4.26pm, Macquarie Generation rebid as much as 720MW from prices below $30/MWh to prices above $250/MWh. The rebid reason was "RRP/Volume tradeoff sensitivities have changed".

There was no other significant rebidding.

Tuesday, 13 September

6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	199.70	33.79	54.74
Demand (MW)	10,377	10,213	10,231
Available capacity (MW)	9,481	9,465	9,615
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	272.50	87.12	69.73
Demand (MW)	10,487	10,333	10,317
Available capacity (MW)	9,468	9,465	9,615

Conditions at the time saw demand around 150MW higher than forecast four hours to dispatch. Prices were higher than forecast and aligned across the southern regions.

At 5.43pm, Macquarie Generation rebid 210MW of capacity across it portfolio from prices of less than $15/MWh to prices around $250/MWh. The rebid reason given was "Price volume tradeoff – load expect to vary from forecast".

There was no other significant rebidding.

Friday, 16 September

8:30 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	151.21	30.87	30.61
Demand (MW)	9,678	9,719	9,713
Available capacity (MW)	8,420	8,935	8,965

Conditions at the time saw demand close to forecast. Prices were aligned across the southern regions throughout this period and were higher than forecast. Macquarie Generation reduced the availability at Liddell unit 4 by 515MW at 4.41am. The rebid was “Power supply investigations”. A similar rebid was made on unit 1 around half an hour earlier, however, this capacity was quickly returned to the market.

There was no other significant rebidding.

Friday, 16 September

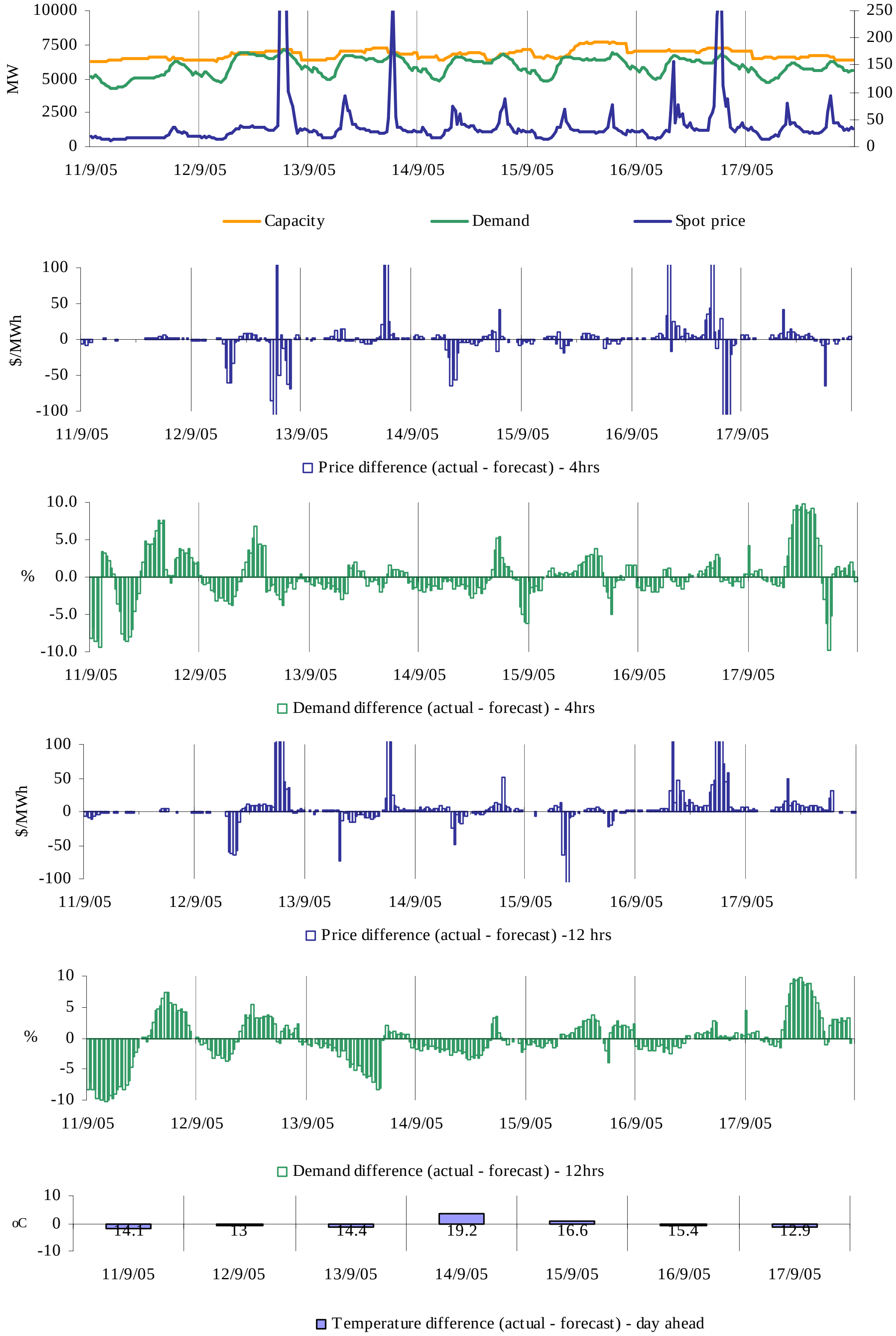
6:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	259.34	38.52	30.00
Demand (MW)	10,591	9,826	9,781
Available capacity (MW)	8,752	8,753	9,315
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	288.96	260.00	90.60
Demand (MW)	10,708	10,376	10,243
Available capacity (MW)	8,752	8,753	9,315
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	290.30	279.55	92.09
Demand (MW)	10,699	10,360	10,238
Available capacity (MW)	8,812	8,813	9,315

Conditions at the time saw demand as much as 750MW higher than forecast four hours earlier. The demand forecast published around 4pm was around 1,200MW higher than the forecast published half an hour earlier. The forecast had gone from under-forecasting actual demand by 300MW to over-forecasting actual demand by more than 850MW. These fluctuations in the demand forecast occurred only three hours to dispatch. Prices were aligned across the southern regions throughout this period and remained aligned in the forecasts following the increase in New South Wales demand.

Eraring Energy rebid 100MW of capacity from prices below $30/MWh to prices around $9,000/MWh. The rebid reason given was “RRP/MW tradeoff bandshift up”.

There was no other significant rebidding.

Figures 33-38: Victoria actual spot price, demand and forecast differences



There were 10 occasions in Victoria where the spot price was greater than three times the weekly average price of $43/MWh. These occurred over the evening peaks on Monday, Tuesday and Friday and at 8.30am on Friday.

Monday, 12 September

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	201.31	285.89	99.00
Demand (MW)	6,856	7,065	6,895
Available capacity (MW)	7,061	6,897	7,429
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	767.99	1147.41	413.14
Demand (MW)	7,026	7,287	7,084
Available capacity (MW)	7,124	6,912	7,059
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	708.65	414.90	411.07
Demand (MW)	7,101	7,241	7,023
Available capacity (MW)	7,149	7,002	6,969
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	217.07	266.80	99.61
Demand (MW)	7,008	7,101	6,893
Available capacity (MW)	7,154	7,031	6,959

Conditions at the time saw demand generally close to forecast. Prices were aligned across the southern regions for most of this period.

From 3pm, International Power rebid all of its capacity at Valley Power into lower prices. This included around 230MW of capacity moved from prices of $400/MWh to prices of less than $100/MWh. The rebid reason given was “Change in price forecasts”. At 6pm, the availability of unit 4 was rebid to zero from 53MW. This bid was effective for the 6pm despatch interval only. The rebid reason given was “Unit trip”. Some of the capacity at Valley Power was forecast to be dispatched during this period before the rebids were received. Rebids made at Hazelwood close to dispatch increased the stations available capacity by 115MW. All of this capacity was priced at less than $20/MWh. The rebid reasons included “Fuel limitations” and “draft plant limit”.

At 4.44pm, LYMMCO rebid 90MW of capacity from prices of less than $20/MWh to prices around $1,000/MWh. The rebid reason given was “Material change in 1632 PD at 1640”.

There was no other significant rebidding.

Tuesday, 13 September

6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	192.97	34.70	57.46
Demand (MW)	6,799	6,725	6,729
Available capacity (MW)	6,940	7,304	7,134
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	270.12	90.54	73.29
Demand (MW)	6,945	6,883	6,881
Available capacity (MW)	6,881	7,304	7,179

Conditions at the time saw demand close to forecast four hours ahead. Prices were aligned across the southern regions throughout this period and were higher than forecast.

At 5.17pm, Tru Energy’s Yallourn unit 3 tripped from full output. The rebid reason given was “Plant failure unit OOS in 15 mins” and reduced the available capacity priced below $5/MWh by 380MW.

At 5.24pm, Alinta rebid 47MW at Bairnsdale from prices above $9,000/MWh to prices of $35/MWh. The rebid reason given was “Market conditions – Price/demand expectation”.

A number of rebids made from 5.24pm by Ecogen, moved a total of 320MW of capacity at Jeeralang from prices above $9,000/MWh to prices of $145/MWh or less. 160MW of this capacity was priced at zero. The rebid reasons given were “Band adj due to PD market conditions” and “Band adj due to add short notice contractual change”.

From 5.30pm, over a number of rebids, International Power shifted 230MW of capacity at Valley Power from prices around $400/MWh to zero. The rebid reason given was “Change in price forecasts”. Earlier in the day, at around midday, the return of Hazelwood unit 8 was brought forward by around four hours. The rebid reason given was “Revised RTS”. This rebid increased by 100MW the available capacity at Hazelwood priced at less than $20/MWh.

There was no other significant rebidding.

Friday, 16 September

8:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	155.54	33.26	32.98
Demand (MW)	6,695	6,720	6,777
Available capacity (MW)	7,067	7,217	7,297

Conditions at the time saw demand close to forecast. Prices were aligned across the southern regions throughout this period.

At 7.01am, Alinta rebid 90MW of capacity at Bairnsdale from prices above $9,000/MWh to prices around $35/MWh. The rebid reason given was “Market conditions – Price/demand expectation”.

At around 8.30am, International Power rebid a total of 124MW of capacity at Valley Power from prices of $131/MWh and $403/MWh to prices of zero. The rebid reason given was “Change in actual prices”.

At 8.30am, Ecogen rebid 143MW of capacity at Jeerlang from prices of more than $145/MWh to zero. Around 110MW of this capacity had been priced above $9,000/MWh. The rebid reason given was “Adj to unit commitment due to PD conditions”.

At 8.30am, LYMMCO rebid 100MW of capacity at Loy Yang A from prices of less than $20/MWh to prices around $250/MWh. The rebid reason given was “Demand tracking ahead of forecast at 08:21”

There was no other significant rebidding.

Friday, 16 September

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	242.21	39.39	30.70
Demand (MW)	6,510	6,347	6,353
Available capacity (MW)	7,256	7,273	7,400
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	265.61	255.48	92.51
Demand (MW)	6,629	6,663	6,619
Available capacity (MW)	7,307	7,278	7,315
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	271.25	284.12	95.65
Demand (MW)	6,764	6,786	6,741
Available capacity (MW)	7,293	7,238	7,310

Conditions at the time saw demand close to forecast. Prices were higher than forecast and were aligned across the southern regions throughout this period.

From 4.30pm, International Power rebid as much as 292MW of capacity at Valley Power into prices of zero from prices around $400/MWh. The rebid reason given was ‘Change in price forecasts”. Further rebids reduced the available capacity across the units by 55MW.

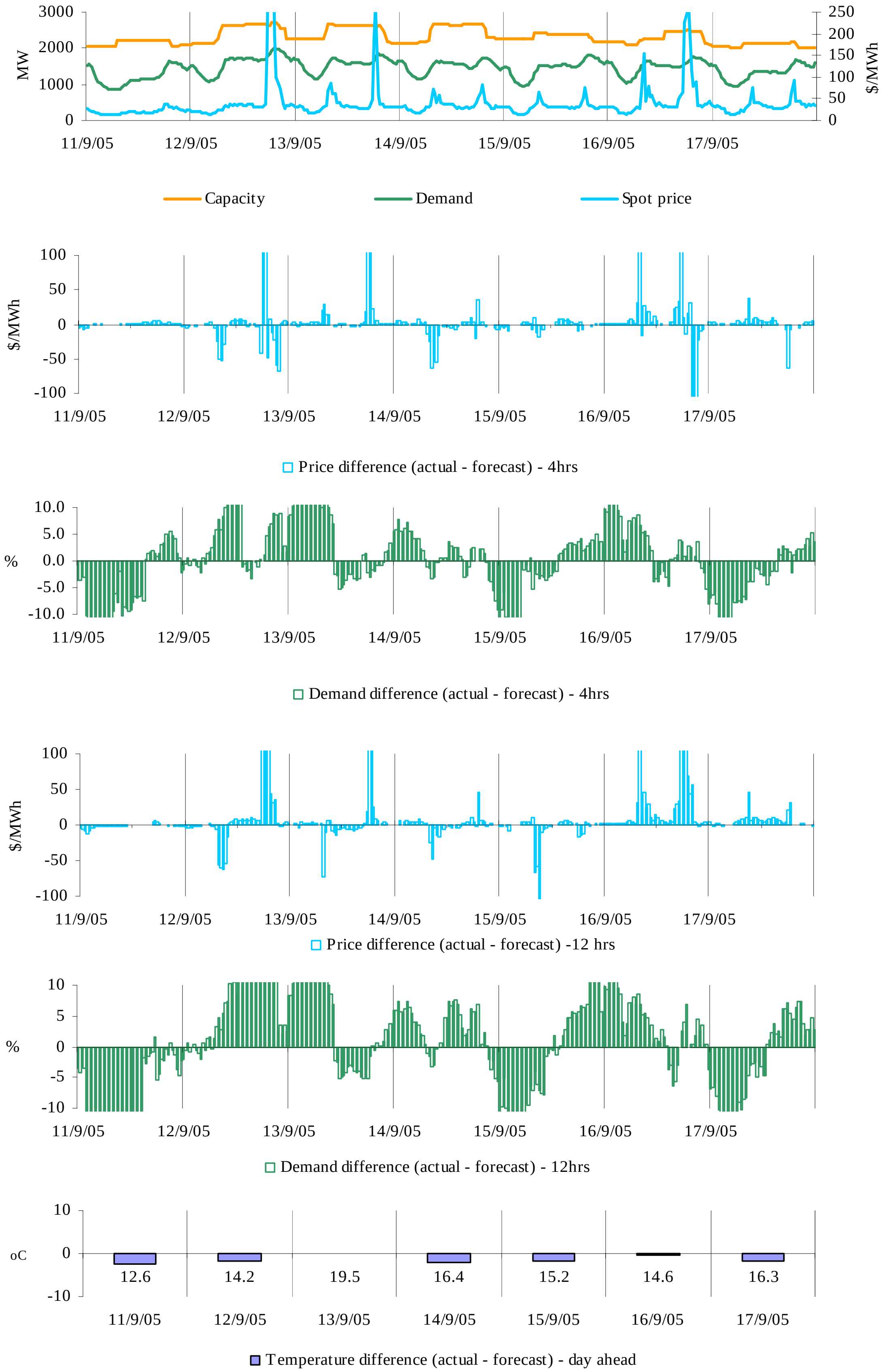
At 4.42pm, AGL rebid 105MW of capacity from prices above $9,000/MWh to prices below $200/MWh. The rebid reason given was “Predispatch: forecast price increase::commit”. At 5.25pm, this capacity was withdrawn from the market and quickly replaced at 5.45pm. The rebid reasons given were “Scheduled commit::daily availability” and “P auxiliary plant failure::correct faulty bid”.

At 4.56pm, LYMMCO rebid as much as 187MW of capacity at Loy Yang A from prices of less than $20/MWh to prices of more than $1,000/MWh. Some of this capacity was further rebid to prices below $250/MWh between 6pm and 6.30pm. The rebid reasons given were “Material variance in demand from 4:32PD at 4:55”, “Demand below expectation at 5.57pm” and “Due to change in PD at 1732 at 18:19”.

At 5.22pm, Ecogen rebid 150MW of capacity at Newport from prices of $300/MWh and $150/MWh to prices of less than $50/MWh. The rebid reason given was ‘Band adj due to portfolio fuel limitation”.

There was no other significant rebidding.

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



There were 10 occasions in South Australia where the spot price was greater than three times the weekly average price of $43/MWh. These occurred over the evening peaks on Monday, Tuesday and Friday and at 8.30am on Friday.

Monday, 12 September

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	164.15	207.04	55.10
Demand (MW)	1,759	1,755	1,487
Available capacity (MW)	2,641	2,673	2,643
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	650.09	295.00	96.00
Demand (MW)	1,847	1,847	1,501
Available capacity (MW)	2,626	2,663	2,643
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	626.90	383.84	355.53
Demand (MW)	1,927	1,909	1,620
Available capacity (MW)	2,703	2,663	2,643
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	200.03	249.26	94.62
Demand (MW)	2,007	1,910	1,692
Available capacity (MW)	2,708	2,663	2,643

Conditions at the time saw demand close to forecast. Prices were aligned across the southern regions for most of this period with South Australia exporting as much as 350MW into Victoria during this period.

By 4.30pm, Origin Energy had rebid all capacity at Quarantine, around 90MW, to zero. This capacity had been priced at $9,000/MWh previously. The rebid reasons given were “Unit testing”, “Extend unit test run” and “Change in PDS, handover bid”.

Over two rebids from 4.51pm, International Power rebid as much as 70MW of capacity at Pelican Point from prices of less than $100/MWh to prices around $1,000/MWh. The rebid reasons given were “Change in price forecast” and “Forecast binding constraint”. At 6.50pm, 30MW of capacity was rebid down from prices above $1,000/MWh to prices around $150/MWh. The rebid reason given was “Change in price forecast”.

At 5.50pm, Tru Energy reduced the availability at Torrens Island unit A2 by 60MW. All of this capacity was priced at less than $60/MWh. The rebid reason given was “Plant conditions – Adj to unit availability”. The availability of this unit was further reduced at 6.10pm to zero. This rebid was reversed 5 minutes later. The rebid reasons given were “Plant conditions – adj to unit availability”. The unit was rebid to full load, 120MW, at 6.40pm. The rebid reason given was “Plant conditions-Adj to unit availability”.

There was no other significant rebidding.

Tuesday, 13 September

6:30 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	183.87	34.15	55.10
Demand (MW)	1,655	1,690	1,739
Available capacity (MW)	2,641	2,641	2,683
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	263.36	89.51	70.28
Demand (MW)	1,761	1,814	1,790
Available capacity (MW)	2,561	2,641	2,683

Conditions at the time saw demand close to forecast. Prices were aligned across the mainland throughout this period.

At 5.29pm, International Power rebid 70MW of capacity at Pelican Point from prices of less than $100/MWh to prices above $300/MWh. The rebid reason given was "Binding constraint".

There was no other significant rebidding.

Friday, 16 September

8:30 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	154.56	33.30	33.09
Demand (MW)	1,578	1,471	1,471
Available capacity (MW)	2,242	2,232	2,232

Conditions at the time saw demand around 100MW higher than forecast. Prices were aligned across the southern regions throughout this period. There was no significant rebidding.

Friday, 16 September

6:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	226.22	38.00	31.18
Demand (MW)	1,565	1,510	1,526
Available capacity (MW)	2,485	2,485	2,232
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	248.56	237.91	89.76
Demand (MW)	1,588	1,577	1,527
Available capacity (MW)	2,498	2,500	2,247
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	257.02	269.93	93.30
Demand (MW)	1,661	1,645	1,548
Available capacity (MW)	2,500	2,500	2,247

Conditions at the time saw demand close to forecast. Prices were aligned across the southern regions throughout this period.

Around midday, International Power increased the availability of Pelican Point by around 240MW, 180MW of this capacity was priced at less than zero. The rebid reason given was "Change in price foecast 1154". At 4.52pm, a further rebid moved 60MW of capacity priced below $100/MWh to prices of $1,000/MWh or more. The rebid reason given was "Change in price forecast 16:50". A number of bids made towards the end of the period moved 80MW of capacity to prices below $150/MWh. The rebid reason given was "NSW demand below forecast' and "Change in price forecasts".

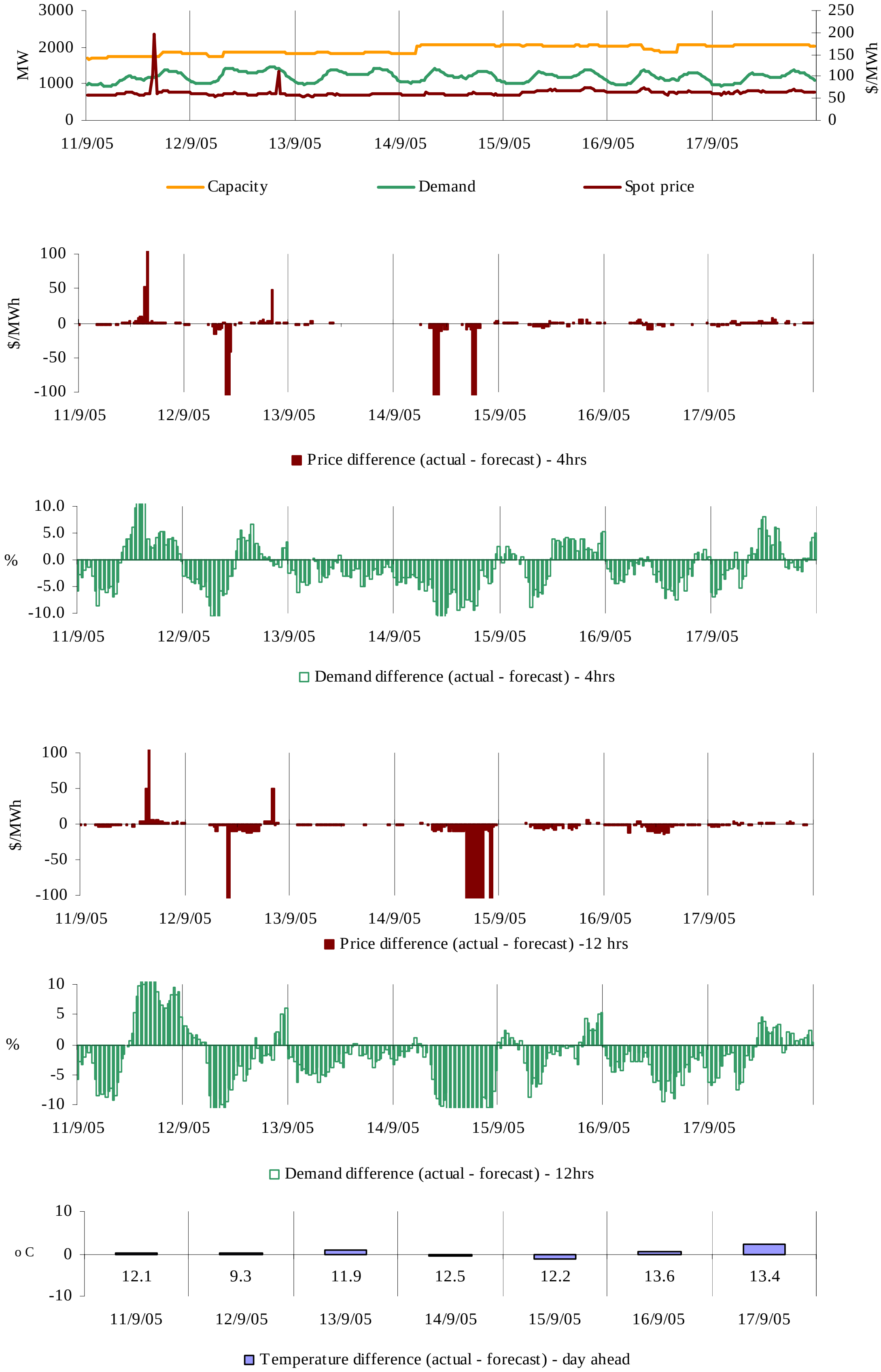
At 4.10pm, Origin Energy rebid 92MW of capacity at Quarantine to zero. This capacity had been priced at $9,000/MWh. The rebid reason given was "Est (N) change in PDS".

At 5.45pm, AGL rebid 80MW of capacity Hallett from prices of more than $9,000/MWh to zero. A further 15MW was rebid to zero from above $9,000/MWh at 6.25pm. The rebid reasons given were "Predispatch:forecast price increase::commit", "Scheduled commit ::revised daily availability", "Predisaptch:forecast price increase::5 min" and "Plant limitations::unit problem".

Tru Energy rebid as much as 220MW of capacity at Torrens Island from prices of less than $40/MWh to prices of $150/MWh and $300/MWh. The rebid reasons given were "Fuel limits-decreasing gen to match fuel profile" and "Fuel limits-decreasing gen to match fuel limits".

There was no other significant rebidding.

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



There was one occasion in Tasmania where the spot price was greater than three times the weekly average price of $63/MWh. This price occurred at 4pm on Sunday.

Sunday, 11 September

4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	195.15	60.30	56.00
Demand (MW)	1,173	1,132	1,048
Available capacity (MW)	1,751	1,751	1,751

Conditions at the time saw demand slightly higher than forecast. At 3.30pm, following advice from Transend that lightning was in the vicinity of the two Farrell to Sheffield lines, NEMMCO reclassified the coincident loss of both lines as credible. Constraints were invoked to manage this reclassification.

These constraints reduced generation at Mackintosh and John Butters by around 100MW. At the same time the requirement for raise 6 second service was increased by 70MW, and 70MW of capacity from the raise 6 second market that had been available was constrained away. As a result, the 6 second requirement could not be met between 3.30pm and 3.45pm. The price was capped at $10,000/MW. The energy price peaked at $330/MWh. The coincident loss of these lines ceased to be a credible contingency at 3.45pm.

There was no significant rebidding.

Figure 51: Queensland closing bid prices, despatched generation and spot price

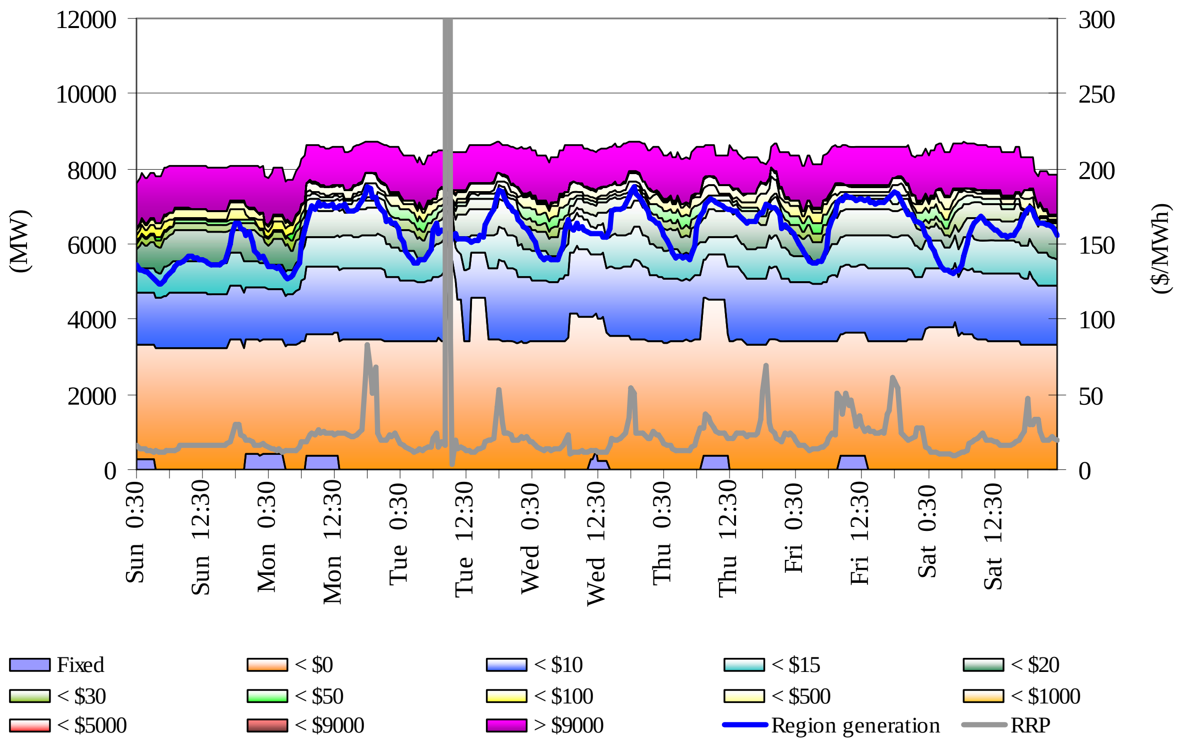


Figure 52: New South Wales closing bid prices, despatched generation and spot price

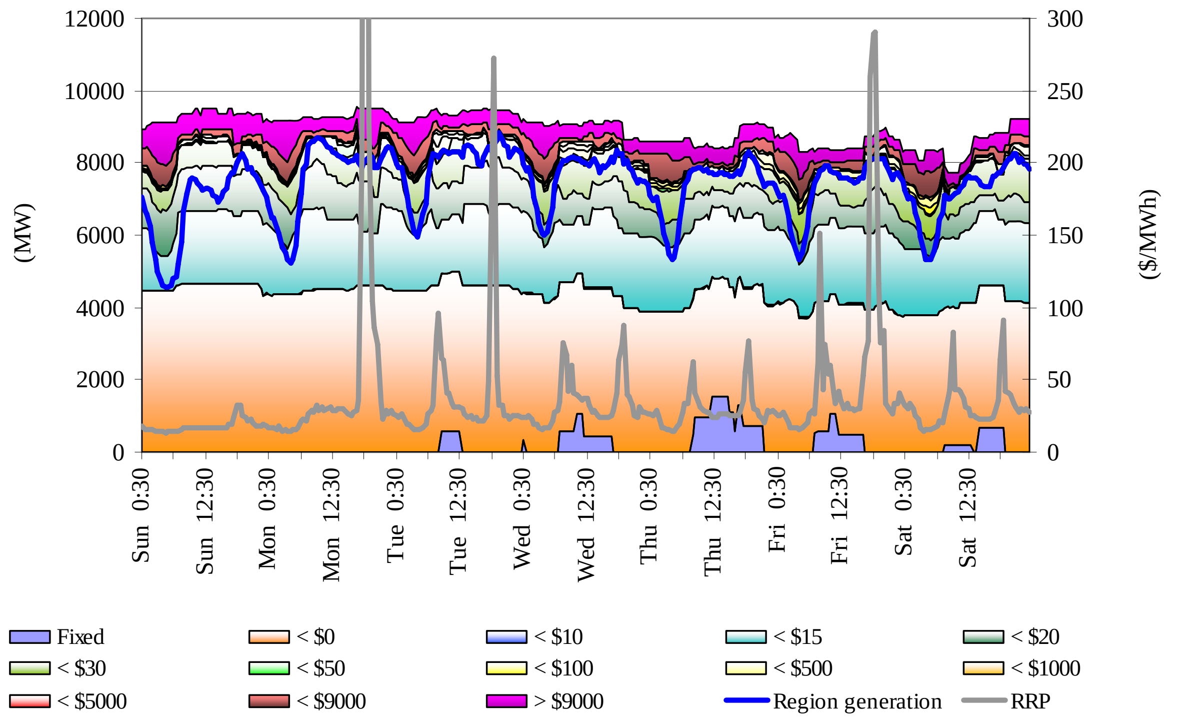


Figure 53: Victoria closing bid prices, despatched generation and spot price

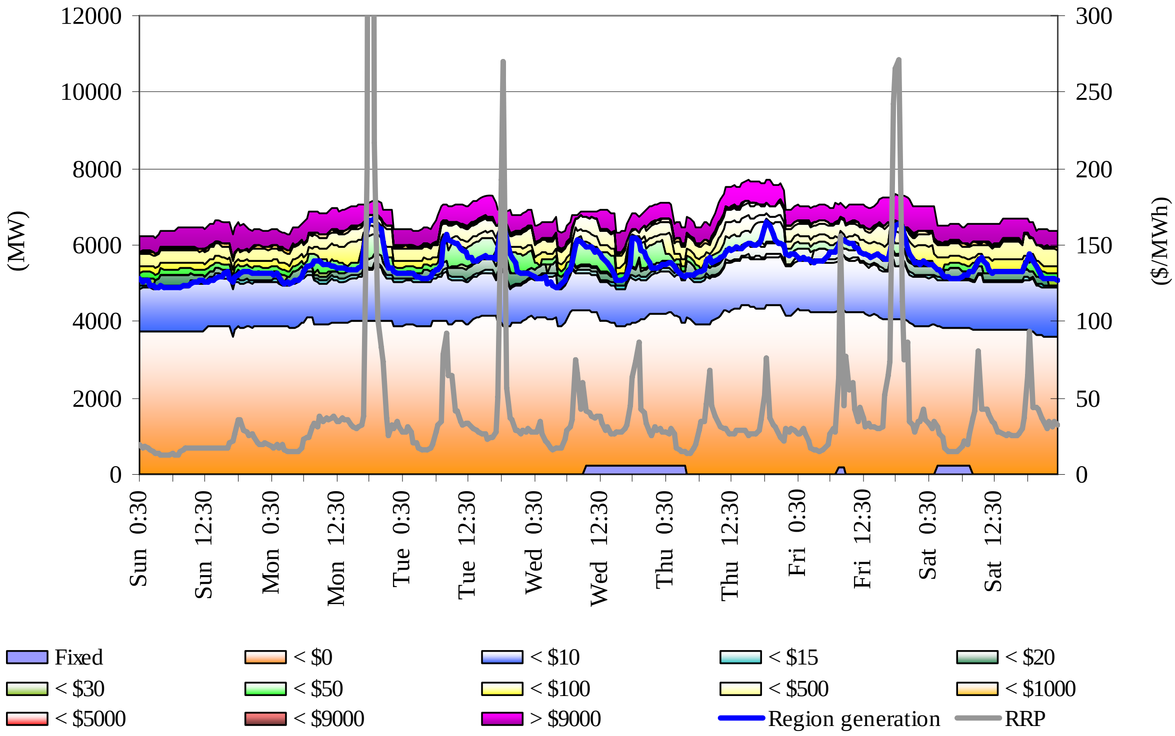


Figure 54: South Australia closing bid prices, despatched generation and spot price

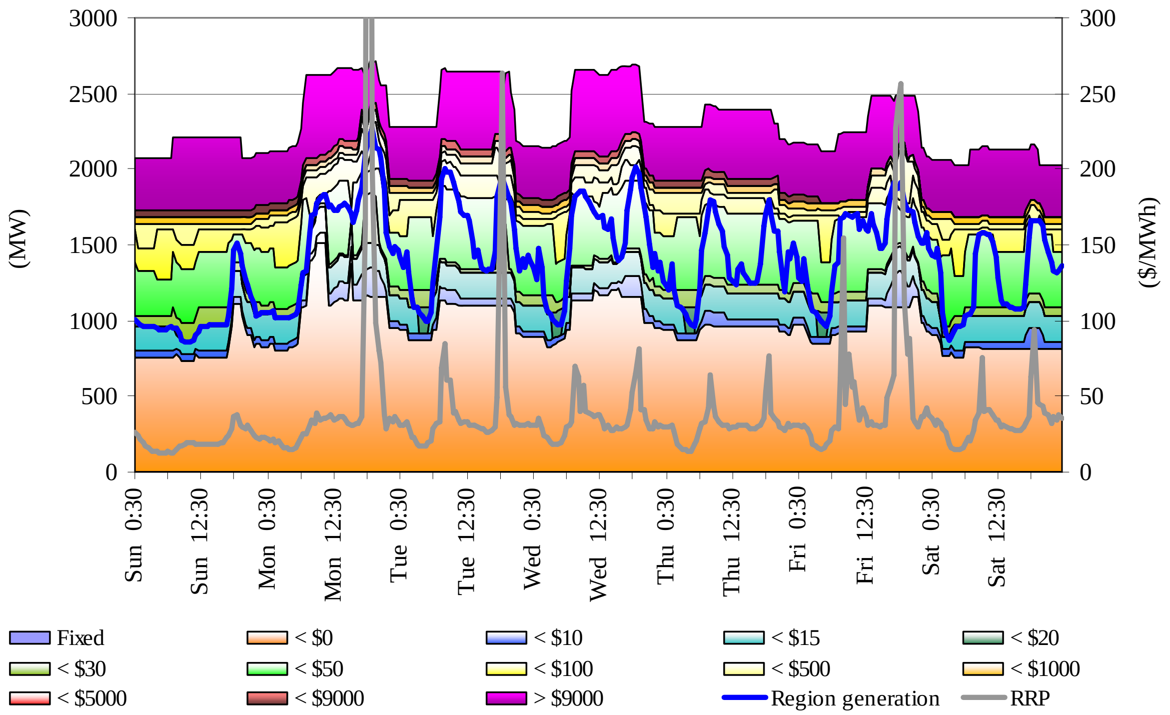
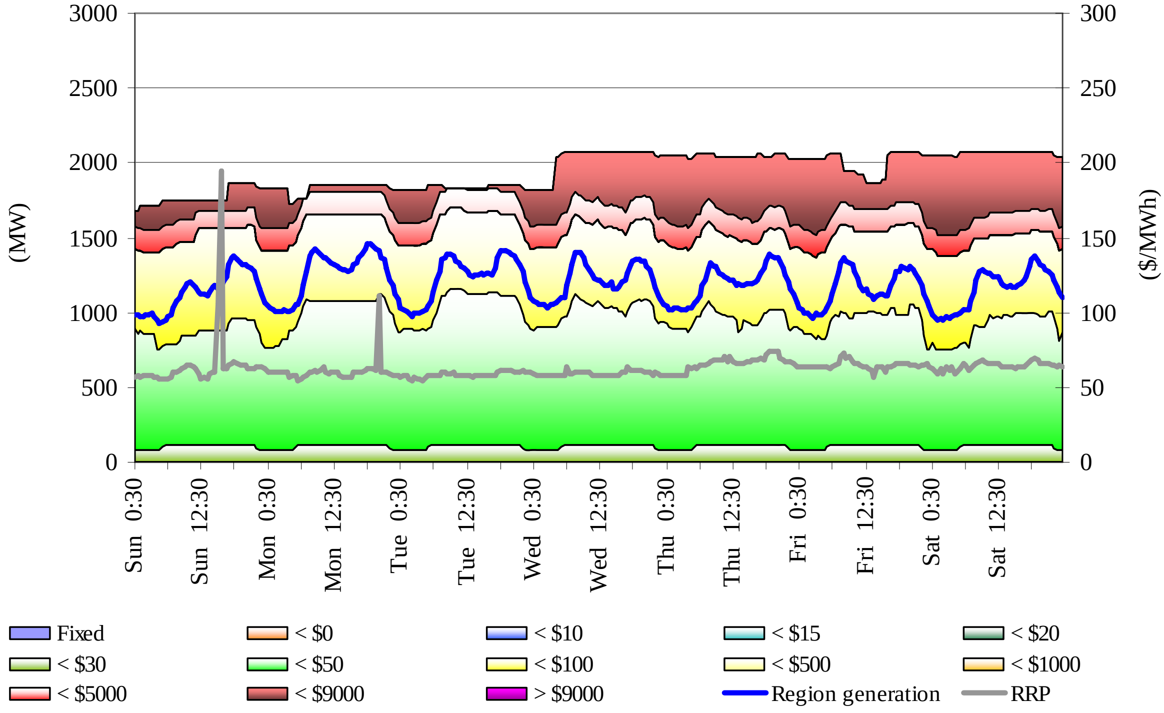


Figure 55: Tasmania closing bid prices, despatched generation and spot price



Ancillary service market

The total cost of ancillary services on the mainland for the week was $505,000 or 0.5 per cent of the total turnover in the energy market. Local requirements in Queensland on Tuesday were as a result of a network outage in New South Wales. These local requirements cost nearly $80,000. Figure 56 summarises the volume weighted average prices and costs for the eight frequency control ancillary services across the interconnected regions.

Figure 56: frequency control ancillary service prices and costs

	Raise 6 sec	Raise 60 sec	Raise 5 min	Raise reg	Lower 6 sec	Lower 60 sec	Lower 5 min	Lower reg
Last week ($)	2.29	1.53	1.60	1.58	0.36	0.44	4.22	1.35
Previous week($)	1.97	1.47	1.13	1.42	0.21	0.29	1.36	1.47
Last Quarter($)	1.43	0.69	0.98	1.36	0.16	0.12	1.16	1.58
Market Cost ($1000s)	$129	$86	$115	$34	$3	$4	$104	$30
Market Cost due to local req ($1000s)	$0	$0	$0	$0	$2	$2	$74	$0
% due to local req	0%	0%	0%	0%	47%	45%	71%	0%
% of energy market	0.09%	0.06%	0.08%	0.02%	0.00%	0.00%	0.07%	0.02%

In Tasmania, ancillary services totaled $351,000 or three per cent of turnover. The price for raise 6 second reached $10,000/MW between 3.30pm and 3.45pm on Sunday when the requirement was not met. Constraints invoked to manage the loss of both Farrell to Sheffield lines to lightning increased the requirement for raise 6 second by close to 70MW and removed around 70MW from the total bid in availability of raise 6 second in the region of 110MW. The constraints were removed from 3.50pm.

Figure 57: 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 ($)	26.34	1.05	1.05	1.05	2.35	1.07	1.08	1.10
Previous week($)	13.36	1.05	1.06	1.06	13.39	1.07	1.06	1.11
Market Cost ($1000s)	$225	$9	$10	$9	$30	$32	$27	$9
% of energy market	1.8%	0.07%	0.08%	0.07%	0.24%	0.25%	0.21%	0.07%

Figure 58 shows the daily breakdown of cost for each frequency control ancillary service.

Figure 58: daily frequency control ancillary service costs

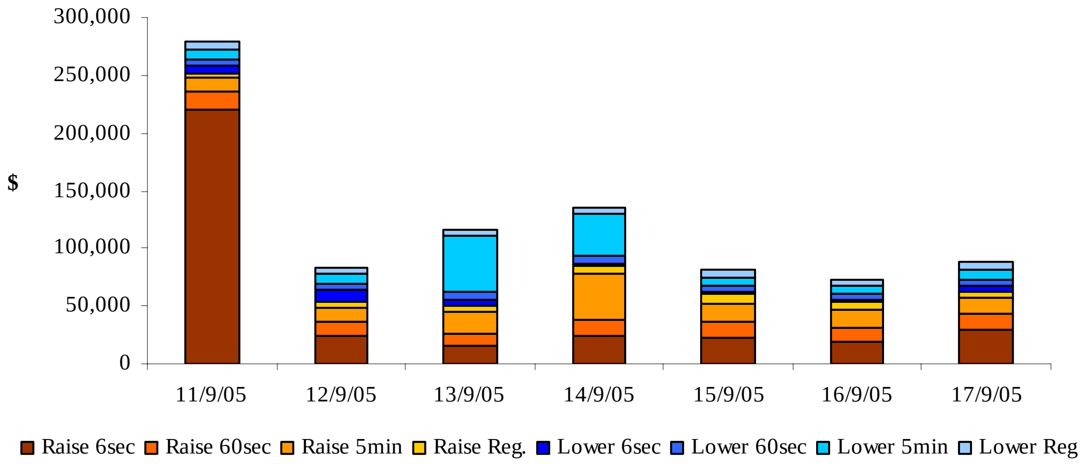
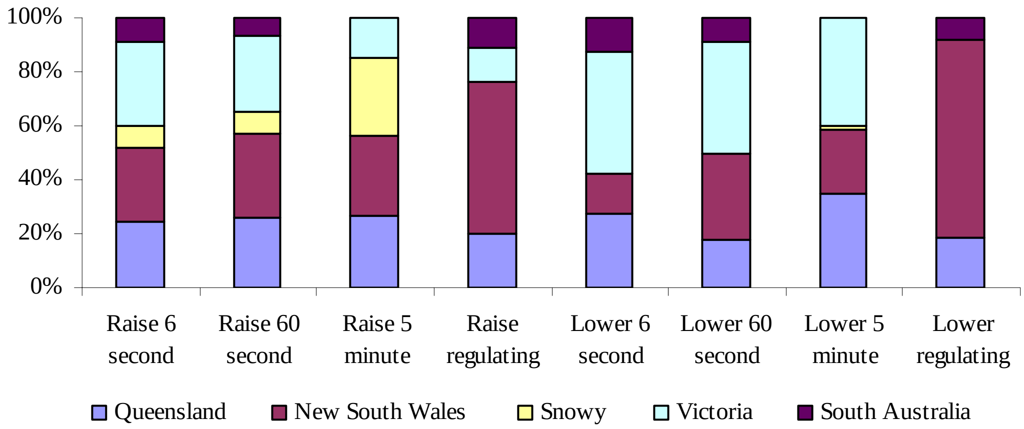


Figure 59 shows the regional weekly participation in each of the ancillary service markets on the mainland.

Figure 59: regional participation in ancillary services on the mainland



Figures 60 and 61 show 30-minute prices for each of the ancillary services.

Figure 60: prices for raise services

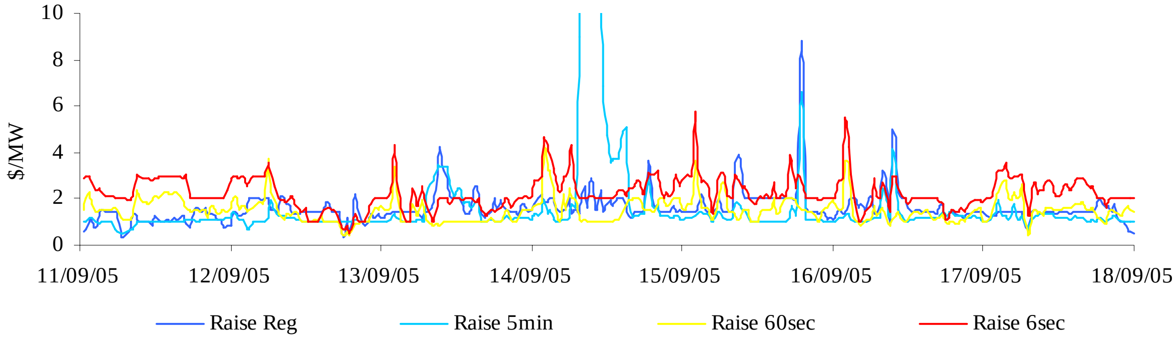


Figure 60A: prices for raise services - Tasmania

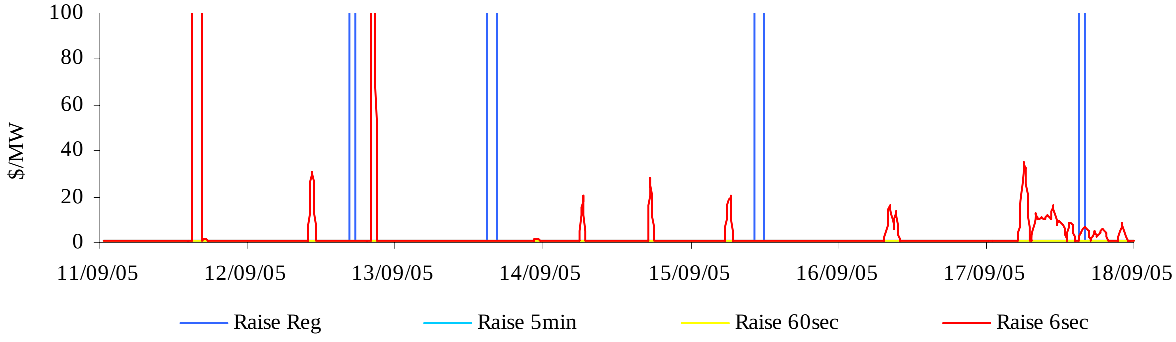


Figure 61: prices for lower services

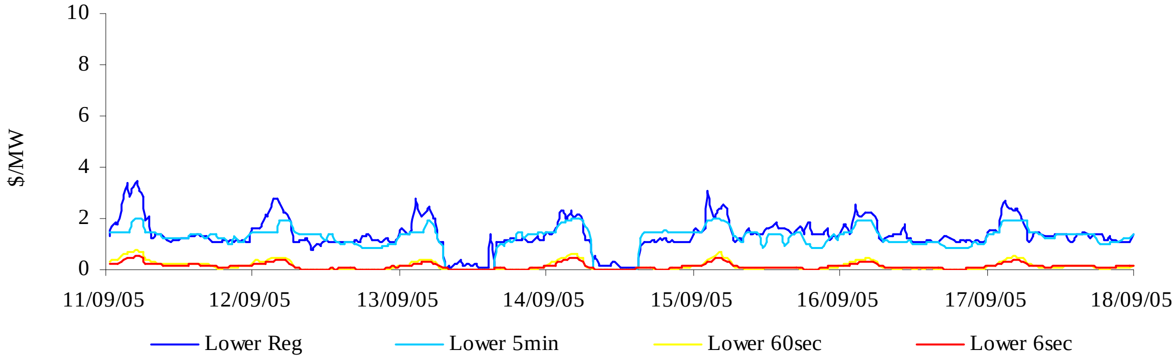
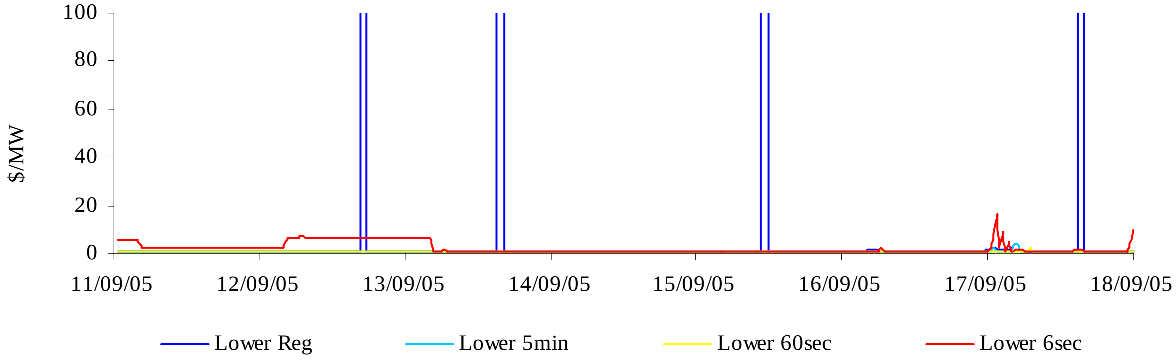


Figure 61A: prices for lower services - Tasmania



Figures 62 and 63 present for both raise and lower services the requirement for each service over the week.

Figure 62: raise requirements

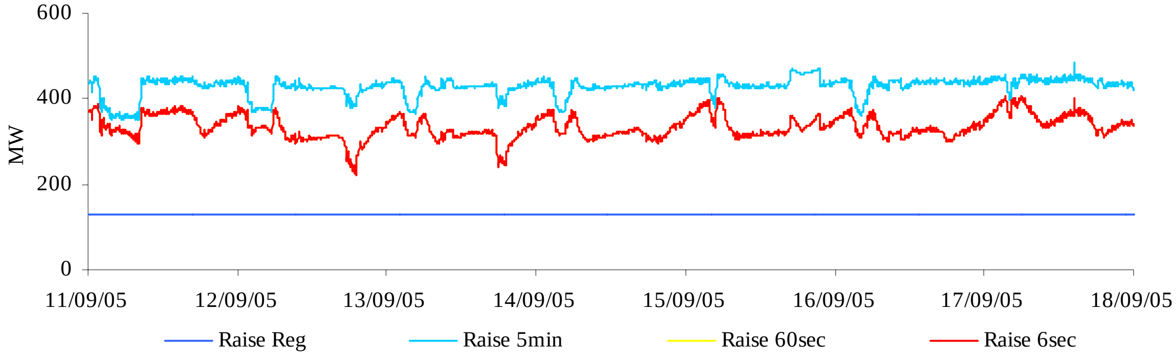


Figure 62A: raise requirements - Tasmania

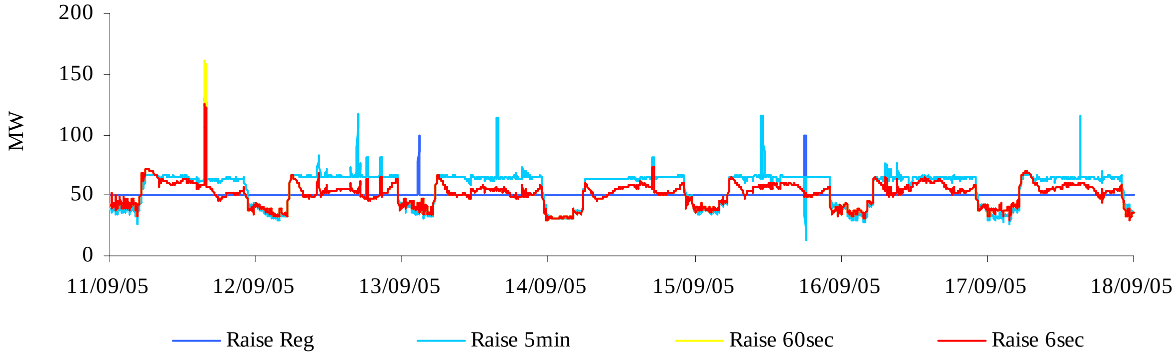


Figure 63: lower requirements

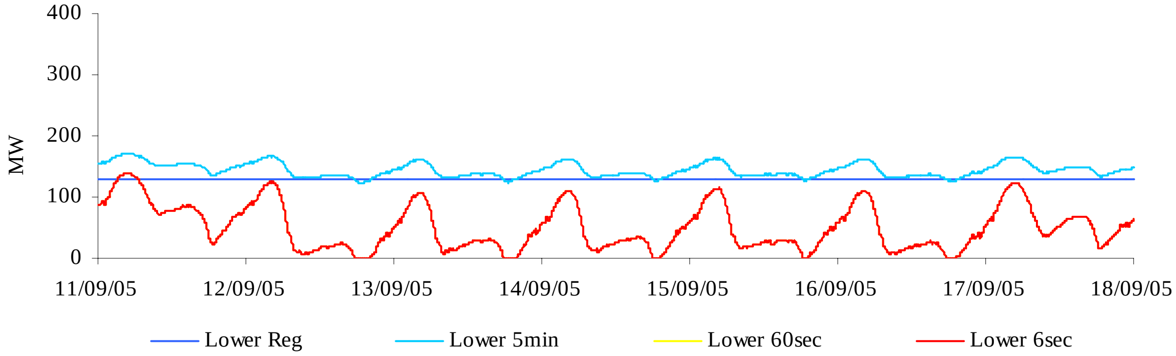


Figure 63A: lower requirements - Tasmania