To	Tim Street, Laurie Counsell – Electricity Commission
From	Ashley Milkop and Daniel Pringle – M-co
Date	29 April 2009
Subject	Market prices for trading periods 37 and 38, 21 April 2009

1. Provisional prices for 21 April 2009 were published by the pricing manager on the morning of 22 April 2009. Would-be final prices have since been calculated but not published. The EGR deadline for their publication was 18:00 Friday 24 April, but the Electricity Commission Board has since ordered a delay of publication.

2. On the afternoon of 22 April 2009, the pricing manger sent market participants 'indicative prices' for trading periods 18:00 and 18:30 and advised that final prices would be published following further investigations.

3. This document focuses on prices for the trading periods beginning 18:00 and 18:30 (hereafter referred to as TP37 and TP38). Our focus is the WIL_T8.T8 constraint and prices at CPK0111 in Wellington.

Prices for trading periods 37 and 38, 21 April 2009

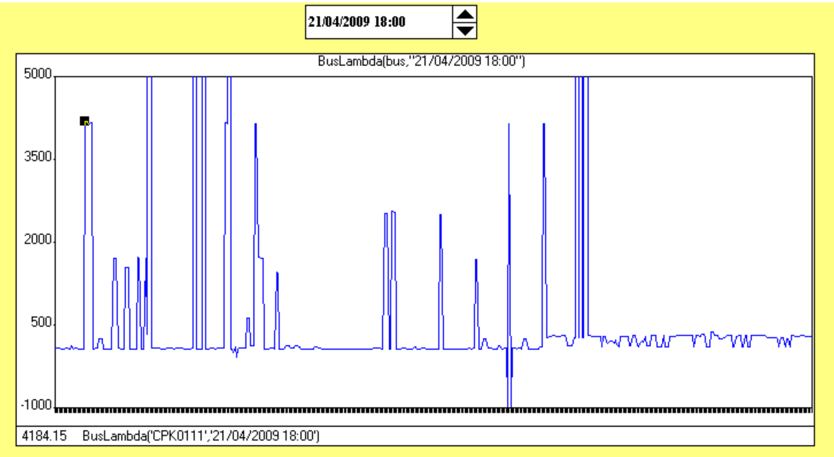
4. The first pricing solve resulted in deficit generation infeasibilities for which a notice was issued. A system operator response was not received before 10:00 and provisional prices were published.

5. The system operator response, received at 10:07, was to resolve deficit generation at CPK0111 by relieving the binding constraint on WIL_T8.T8. For trading period TP37, the limit was raised from 110 to 111 MW, and for TP38 from 110 to 113 MW.

6. These revisions removed the infeasibilities but the constraint was still binding and gave rise to a high spring washer price (HSWP) situation in both periods, for which a notice was issued.

7. In accordance with the Rules, the system operator responding to the HSWP situation by relaxing WIL_T8.T8, by 1%, to 112.11 MW for TP37 and to 114.13 MW for TP38.

8. Would-be final prices were then calculated. These prices are shown below for TP37. (Prices for TP38 are similar but with slightly lower amplitude variations).



9. For trading period 37, the highest price is $4184.15/MWh at CPK0111. In the lower North Island, 37 nodes have prices above $1000/MWh and three have negative prices, the most negative being $-992.16/MWh at WIL0331. Upper South Island prices are about $300/MWh.

Verification of would-be final price at CPK0111, TP37

10. A marginal load analysis confirms that would-be final prices at CPK0111 for TP37 and TP38 are indeed the cost to supply a nominal load increase of 1 MW at this node. Below are details for TP37.

11. The system was highly sensitive to additional load, so we increased load by +1 kW and scaled results to the nominal case of a +1 MW load increase.

12. The increase in system cost equalled the node price, confirming that the node price was a legitimate marginal price.

13. The theoretical 1 MW demand increase at CPK0111 resulted in a system cost increase of $4184.15. This is the node price in the would-be final prices, and comprises:

    a. $3885.76 for energy; and

    b. $298.39 for reserve.

14. The 1 MW increase was modelled by an energy output increases of 17.9 MW at 'PARTY A' and 2.9 MW at 'PARTY B', and an energy output decreases of 14.8 MW at 'PARTY C' and 1 MW at 'PARTY D'.

15. The energy increase at 'PARTY A' cost $4475.00 (for $250 price). The energy increase at 'PARTY B' cost $153.87 (for $53.06 price).

16. The energy decrease at 'PARTY C' saved $666.59 (for $45.04 price). The energy decrease at 'PARTY D' saved $80 (for $80 price).

17. Changes in modelled reserves were to increase partially loaded reserve (PLRO) by 14.8 MW at both 'PARTY C' and 'PARTY E', and to decrease PLRO by 1 MW at 'PARTY F'. Tail water depressed reserve (TWRO) was increased by 1 MW at 'PARTY D'.

18. The PLRO increase at 'PARTY C' cost $222.59 (for $15.04 reserve price). The PLRO increase at 'PARTY E' cost $88.80 (for $6.00 reserve price). The TWRO increase at 'PARTY D' cost $0.02 (for $0.02 reserve price).

19. The PLRO decrease at 'PARTY F' saved $15.00 (for $15.00 reserve price).

20. The net marginal cost of supplying the theoretical 1MW to CPK0111 is therefore ($4475.00 + $153.87 - $666.59 - $80) + ($222.59 + $88.80 + $0.02 - $15.00) = $3882.28 + $296.41 = $4178.69. This is the calculated node price for this trading period (to within a 0.5% difference due to rounding and differencing small numbers in the +1kW load increase analysis).

21. These numbers are summarized in the table on the next page:

Time	Island	Market Node	Type	Change in cleared amount (MW)	Price $/MWh	Cost (saving)
18:00	SI	'PARTY A'	ENOF	17.9	250	$4,475.00
18:00	NI	'PARTY B'	ENOF	2.9	53.06	$153.87
18:00	NI	'PARTY C'	ENOF	-14.8	45.04	-$666.59
18:00	SI	'PARTY D'	ENOF	-1	80	-$80.00
	Total		Energy			$3,882.28
18:00	NI	'PARTY C'	PLRO	14.8	15.04	$222.59
18:00	NI	'PARTY E'	PLRO	14.8	6	$88.80
18:00	SI	'PARTY D'	TWRO	1	0.02	$0.02
18:00	SI	'PARTY F'	PLRO	-1	15	-$15.00
	Total		Reserves			$296.41
18:00	Total					$4,178.69

Verification of would-be final price at CPK0111, TP38

22. We now present details of the above analysis for CPK0111 in trading period TP38.

23. The system was highly sensitive to additional load, so we increased load by +1 kW and scaled results to the nominal case of a +1 MW load increase.

24. The increase in system cost equalled the node price, confirming that the node price was a legitimate marginal price.

25. The theoretical 1 MW demand increase at CPK0111 resulted in a system cost increase of $3838.75. This is the node price in the would-be final prices, and comprises:

    c. $3580.91 for energy; and

    d. $257.84 for reserve.

26. The 1 MW increase was modelled by an energy output increases of 16.9 MW at 'PARTY G' and 1.9 MW at 'PARTY D', and an energy output decrease of 15.4 MW at 'PARTY B'.

27. The energy increase at 'PARTY G' cost $4,225 (for $250 price). The energy increase at 'PARTY D' cost $152.00 (for $80 price).

28. The energy decrease at 'PARTY B' saved $817.12 (for $53.06 price).

29. Changes in modelled reserves were to increase partially loaded reserve (PLRO) by 16.3 MW at 'PARTY E', and to decrease PLRO by 1.9 MW at 'PARTY F'.

30. Tail water depressed reserve (TWRO) was decreased by 1.9 MW at 'PARTY D'. Interruptible load reserve (ILRO) was increased by 16.3 MW at ALB0331.

31. The PLRO increase at 'PARTY E' cost $163.00 (for $10 reserve price). The PLRO increase at 'PARTY F' cost $28.50 (for $15 reserve price). The TWRO decrease at 'PARTY D' saved $0.04 (for $0.02 reserve price).

32. The ILRO increase at 'PARTY H' cost $65.04 (for $3.99 reserve price).

33. The net marginal cost of supplying the theoretical 1MW to CPK0111 is therefore ($4225.00 + $152.00 - $817.12) + ($163.00 + $28.50 + $65.04 - $0.04) = $3559.88 + $256.50 = $3816.38. This is the calculated node price for this trading period (to within a 0.1% difference due to rounding and differencing small numbers in the +1kW load increase analysis).

34. These numbers are summarized in the table below:

Time	Island	Market Node	Type	Change in cleared amount (MW)	Price $/MWh	Cost (saving)
18:30	SI	'PARTY G'	ENOF	16.9	250	$4,225.00
18:30	SI	'PARTY D'	ENOF	1.9	80	$152.00
18:30	NI	'PARTY B'	ENOF	-15.4	53.06	-$817.12
	Total		Energy			$3,559.88
18:30	NI	'PARTY E'	PLRO	16.3	10	$163.00
18:30	SI	'PARTY F'	PLRO	1.9	15	$28.50
18:30	SI	'PARTY D'	TWRO	-1.9	0.02	-$0.04
18:30	NI	'PARTY H'	ILRO	16.3	3.99	$65.04
	Total		Reserves			$256.50
18:30	Total					$3,816.38

Wilton T8 Modelling

35. The Wilton T8 constraint was 139 MW in trading period 35, and reduced to 110 MW from trading period 36. It bound in trading periods 37 and 38.

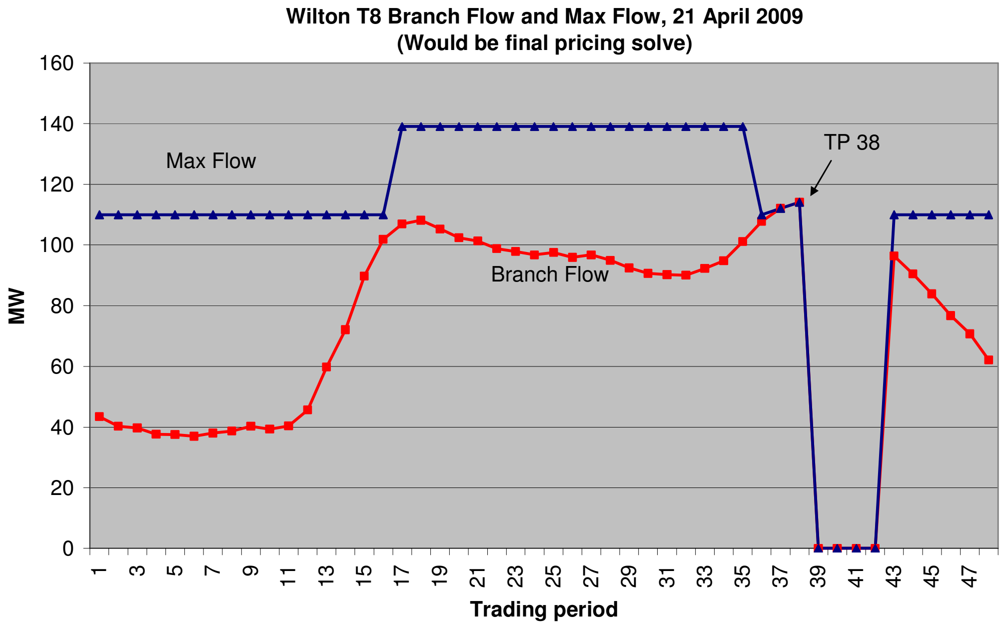
36. Because of the constraint, CPK0111 became infeasible for trading periods 37 and 38. To resolve this, the system operator relaxed the constraint to the point at which CPK0111 became feasible.

37. The constraint was relaxed a second time in accordance with the high spring washer price situation rules.

38. The transformer was removed from service altogether from trading period 39.

39. The rules dictate that the whole of the trading period must be modelled on what was in effect at the start of the trading period. I.e. even if the constraint was changed early in a trading period, this is not taken into account until the next trading period.

40. The limit of the constraint and the modelled flow for WIL_T8.T8 for the would-be final pricing solve are illustrated in the graph on the next page. The curves intersect for TP37 and TP38, indicating that the constraint was binding, despite the relaxation.



Conclusion

41. The pricing manager is satisfied that the would-be final prices 21 April 2009, as calculated on 22 April 2009, are correct to the extent that:

    a. The pricing process was performed correctly;

    b. Action undertaken by the system operator to resolve the infeasible deficit generation infeasibilities and subsequent HSWP situations was correct and in keeping with the Rules; and

    c. To the best of our knowledge, the inputs provided under the Rules by other parties which are required to perform the pricing process were present and correct.