Determination of Critical Contingency Price

in respect of the critical contingency of 3rd March 2012

Tim Denne (tim.denne@covec.co.nz)
20th April 2012

Introduction

1. This report sets out my determination of a Critical Contingency Price as required by the Gas Governance (Critical Contingency Management) Regulations 2008 ('the Regulations'). The Critical Contingency Price is required in respect of the critical contingency of 3rd March 2012.

2. A critical contingency is defined under the Regulations. It is triggered when the operating pressure reaches a low threshold that defines the pressure required to "maintain the supply of gas across the relevant part or parts of the transmission system and to avoid disruption of distribution systems connected to the transmission system" (Regulation 25(1)(a)(iv)).

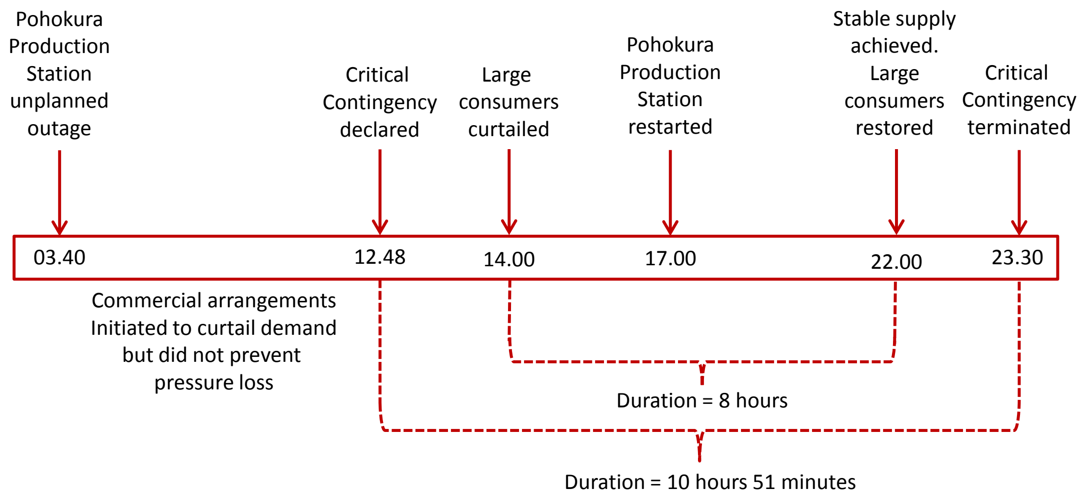
3. A draft report and recommended price was discussed at a workshop with interested parties on 16th April 2012. There were no objections to the proposed price.

4. My determination is that the critical contingency price for 3rd March 2012 is \$11.10/GJ. The explanation is given below.

The Event

5. A critical contingency was declared on the Maui pipeline on 3rd March 2012 following an unplanned outage of the Pohokura Production Station. The plant shutdown initially occurred as a result of a power outage at 3.40am, but production could not restart because of a fault in the plant heating system. The outage resulted in reduced supply and a low pressure being recorded at Rotowaro that fell below the threshold that triggered a critical contingency. The sequence of events is shown in Figure 1.

Figure 1 Sequence of events for Critical Contingency of 3rd March 2012



6. In the absence of any additional supply, it was estimated that large consumers would need to reduce demand by approximately 71% following a reduction in potential supply to 5,300 GJ/hour, 59% of the normal demand of 12,800 GJ/hour (Table 1).

Table 1 Required reduction in consumption following outage (GJ/hour)

Customer	Pre-outage	Post-outage	% reduction required
Large consumer demand	10,600	3,100	71%
Other consumer demand	2,200	2,200	0%
Total offtake	12,800	5,300	59%

7. Schedule 2 of the Regulations defines the order in which curtailment of gas consumption is to occur in the event of a critical contingency. There are eight bands and the order can be viewed as "representing a cost schedule or merit order, though it also reflects some pragmatism over freeing up significant volumes of gas quickly."[1] In the critical contingency on 3rd March, gas storage (band 0), electricity generators and other large consumers[2] (band 1a and 1b consumers) were curtailed.

8. Prior to the declaration of the Critical Contingency, Transpower and the electricity generators were informed of the potential need to curtail their consumption, possibly to one third of then current levels (as at 8:30am), depending on levels of increase in supply. Subsequently, supply increased as follows:

- Kupe Production Station increased its production rate at 09:00 am from 1,900 GJ/hour to 2,600 GJ/hour;

---

[1] Small, John (2010) Critical Contingency Price: 13 July 2010. Final Report, 6 September 2010

[2] Those consuming more than 15 TJ per day (bands 1a and 1b). The bands are defined in Schedule 2 of

[2] Those consuming more than 15 TJ per day (bands 1a and 1b). The bands are defined in Schedule 2 of the Regulations

- Oaonui Production Station increased its production rate at 10:00 am from 4,600 GJ/hour to 5,700 GJ/hour;

9. Following this increase in supply, the Critical Contingency Operator (CCO) revised the estimates of the required reductions in consumption. Reduction requirements were included in the CCO's plan and notified to Transpower and the electricity generators (Table 2). Following confirmation that the Critical Contingency had been triggered, the plan was confirmed and generators agreed to reduce to these levels by 14:00.

10. The CCO issued a notice at 13:20 directing demand to be curtailed by band 0, 1a and 1b large consumers by 14:00 to the levels agreed. The amounts included some allocations to cogeneration plants that were used to meet the requirements of heat customers. The Taranaki Combined Cycle (TCC) plant (and the Stratford peaking plants) were not allocated any gas because they had access to stored gas. In addition to electricity generators, directions to curtail demand by 14:00 were also sent to Methanex and Ballance Ammonia-Urea plant, both in curtailment band 1b.

Table 2 Maximum gas usage by electricity generators (GJ/hour)

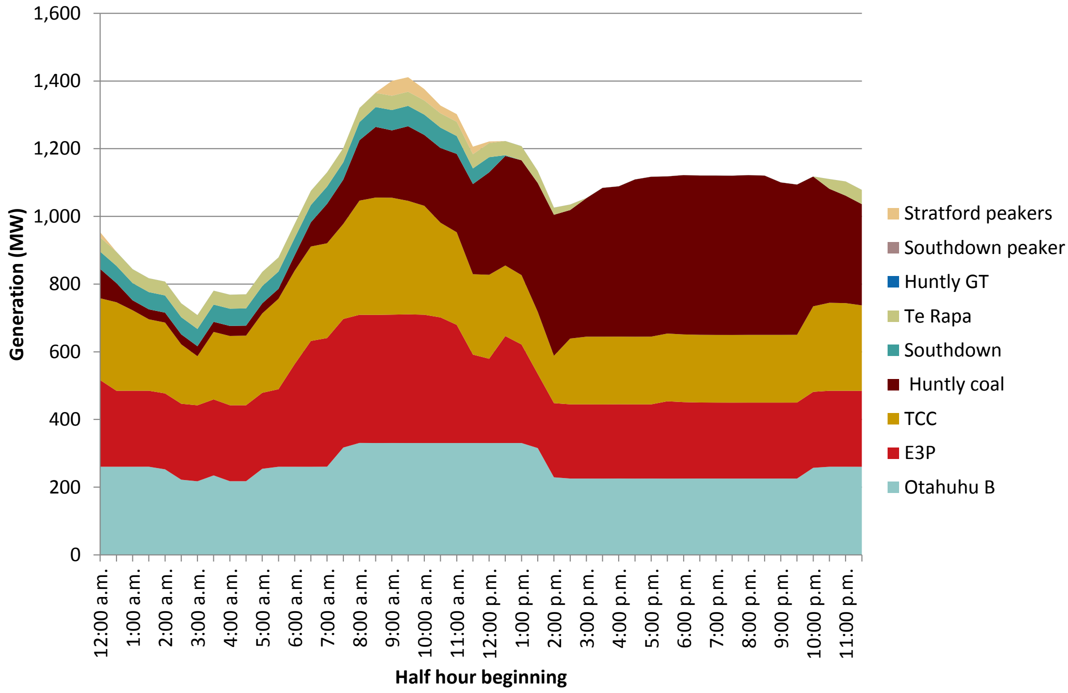
Customer	Total	Available for electricity generation
Huntly power stations (e3P and gas turbine)[1]	1,700	1,700
Otahuhu power stations	1,700	1,700
Te Rapa Cogeneration plant	300	
Southdown power station	62	
Taranaki Combined Cycle and Stratford peakers	0	
Total	3,762	3,400

[1] The Huntly Power Station units 1-4 (curtailment band 1a) that normally generate using coal, but are capable of using gas, were curtailed completely from using gas from 14:00

11. Pohokura Production Station was at start-up pressure rates by 16:00 and was supplying 4,100 GJ/hour by 16:00, 8,800 GJ/hour by 19:00 and 9,400 GJ/hour by 21:00. Generators were allowed to restore generation to normal levels at 22:00 pm.

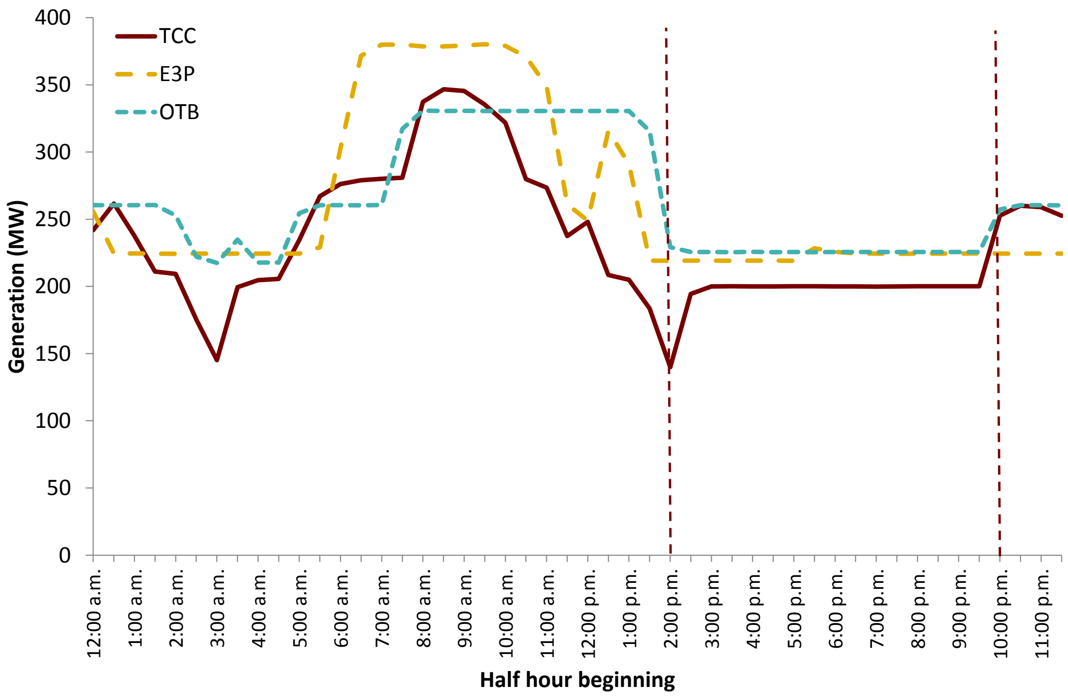
12. As a result of the restrictions to gas availability, generation by the individual thermal electricity generation plants was as shown in Figure 2. Between 14:00 and 22:00 generation continued at TCC using stored gas, at e3P and Otahuhu B. Electricity generation was stopped at Southdown and Te Rapa; there was no generation by the Stratford peakers, the Huntly gas turbine or the Southdown peaker. Generation at the Huntly coal plant increased during the period the gas generation plants were curtailed.

Figure 2 Generation by dispatchable thermal plants



13. In Figure 3 we show levels of generation at the three CCGT plants; at 14:00 pm there is an increase in production at TCC (relative to immediately prior) and a reduction in generation at e3P and Otahuhu B. Generation increases at all three stations from 22:00 pm.

Figure 3 Generation at CCGT plants



Concepts Relevant to Setting a Critical Contingency Price

14. As noted above, the critical contingency was managed by the CCO directing the gas storage facility at Ahuroa not to take gas into storage, and the electricity generators and other large users to reduce consumption. These steps were taken to ensure that pressure and line-pack did not fall to critical levels. In this context, the critical contingency price is to be used, retrospectively, to settle imbalances between the amount parties have contractually agreed to inject and the amount injected. It also is assumed to have a forward-looking incentive effect, in the sense that, because it is widely announced, the predicted critical contingency price would be expected to be taken into account by those that must pay the price.

15. Statutory guidance for setting price during a critical contingency is provided under Section 71 of the Regulations. This is reproduced below.

> **71. *Determining critical contingency price***
> *(1) The industry expert must determine the critical contingency price in dollars per gigajoule of gas.*
> *(2) The industry expert must seek to set the critical contingency price at a level that reflects the price that would be established by an efficient short-term market that allocated scarce gas resources to the highest value uses during the critical contingency.*
> *(3) If—*
> > *(a) only consumers in curtailment bands 0 and 1a, or 0, 1a, and 1b, were curtailed during the critical contingency, the industry expert must base his or her determination on the prices in the wholesale market for electricity during the critical contingency except where that would be contrary to subclause (2); and*
> > *(b) any other circumstances apply, the industry expert must take into account the following matters:*
> > > *(i) the prices in the wholesale market for electricity during the critical contingency; and*
> > > *(ii) the economic cost of the loss of gas supply to those consumers who had their gas supply curtailed; and*
> > > *(iii) any other matters that the industry expert considers relevant to achieving subclause (2).*

16. Section 71(2) makes clear that the intent of the critical contingency price is that it mimics what a competitive short-run market price would be if the market was allocating the limited quantity of gas available during the critical contingency. Normally this would be the outcome of interactions between supply and demand, ie the volume which gas suppliers would be willing to supply at a given price and the volume which consumers would consume at that same price.

17. Because of the limited curtailments (bands 0, 1a and 1b only), according to Section 71(3)(a) the assessment should be based on prices in the wholesale electricity market during the critical contingency, unless this is contrary to the price defined by an efficient market as described in Section 71(2) of the Regulations.

Approach Used to Define the Critical Contingency Price

Supply Factors

18. Price in a spot gas market would be set by the interaction of supply and demand. Gas is available for supply in different tranches with different costs. In the time leading up to the critical contingency, additional volumes were supplied from Kupe Production Station (an additional 700 GJ/hour at 9am) and Oaonui Production Station (an additional 1,100 GJ/hour at 10:00 am). This was a market response given some expectation of the price available during this period;

19. In the afternoon of 3rd March 1,000 GJ of gas were available in the balancing gas exchange (BGX) at a price of $14.95/GJ but were not purchased.

Demand Factors

20. According to Section 71(3) (a), the key consideration in setting the critical contingency price, is the demand side and specifically, the electricity generators' willingness to pay for gas during this period, given the wholesale price. The willingness to pay is determined by the price of electricity, less any (non-fuel) variable costs of generation, and the plant's heat rate. A price that the generators would be willing to pay for gas delivered can be calculated, and needs to be estimated net of the costs of delivery, ie the transmission charges. The costs of carbon are not removed from the price as the generators are not responsible for these. In other words, the gas price is a carbon-inclusive price. Relevant data on the generation plants are included in Table 3.

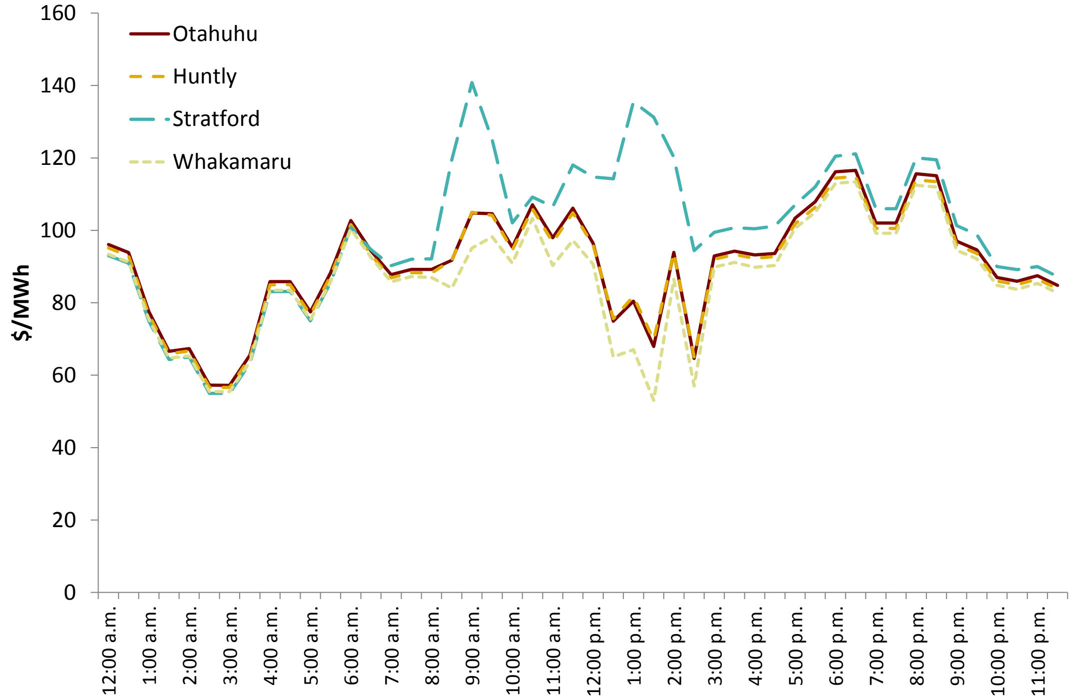
Table 3 Generation plant data

	Capacity (MW)	Heat rate (GJ/GWh)	VOM ($/MWh)	Gas Delivery ($/GJ)	Maximum GJ/hour
Taranaki CC	380	7,760	4.3	0.10	2,941
Stratford peakers	200	10,000	8.2	0.10	2,000
Huntly e3P	385	7,400	4.3	0.60	2,849
Huntly GT	40	10,525	8.2	0.60	421
Otahuhu B	380	7,240	4.3	1.00	2,751
Te Rapa	45	10,600	4.2	1.00	477
Southdown Main Station	125	8,700	4.3	1.00	1,088
Southdown OCGT	50	10,000	8.2	1.00	500

Source: PB (2012) 2011 NZ Generation Data Update. Ministry of Economic Development; PB (2009) Thermal Power Station Advice. Report to the Electricity Commission; electricity generators, personal communications (values for TCC and Otahuhu B are average heat rates for the 3rd March)

21. We combine this with data on the electricity price at a number of nodes (Figure 4).

Figure 4 Nodal electricity prices (3rd March 2012)

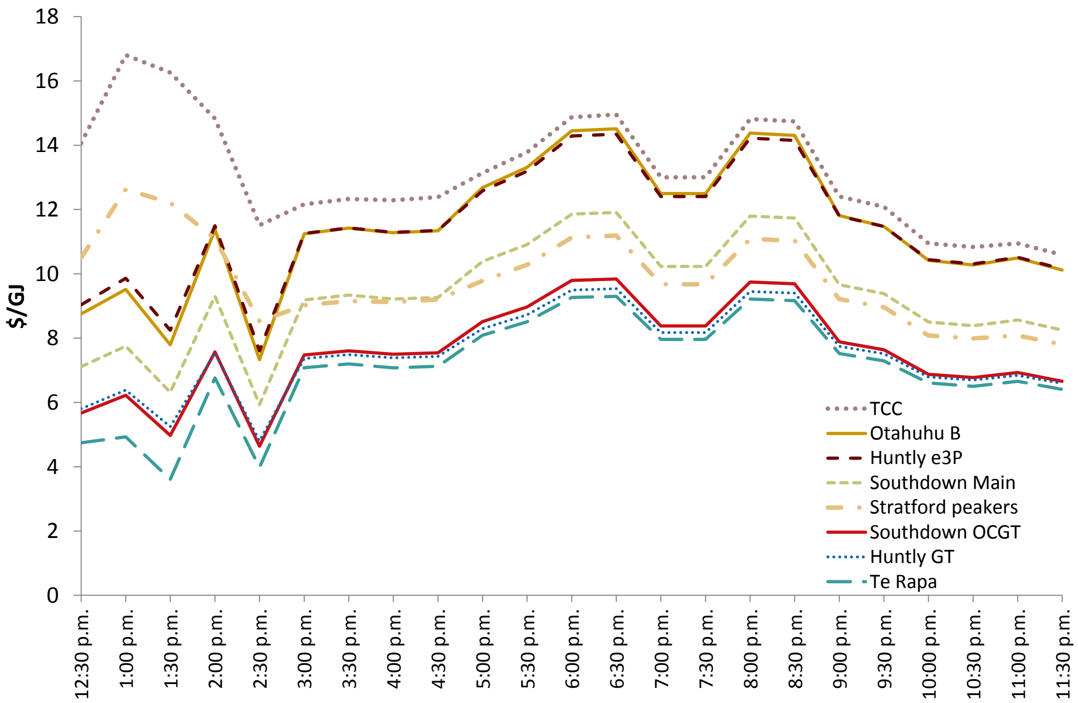


22. Using these data, and assuming that the electricity price is exogenous, as suggested by Section 71(3)(b)(i) of the Regulations, we can estimate the willingness to pay for gas of the individual plants. Treating the electricity price as exogenous is reasonable given the objective to mimic the allocation of limited supplies of gas as was achieved through physical rationing.

23. Estimates of the willingness to pay for gas are shown in Figure 5. The highest willingness to pay is at TCC. Despite it having a higher heat rate than the other CCGTs, it has lower costs of gas supply (transmission costs). In addition, over some periods of the day, the electricity price was significantly higher at the Stratford node (Figure 4). In practice, the Taranaki plants (TCC and the Stratford peakers) would use stored gas when gas prices rose above the "normal" price, ie the price that gas would be expected to return to in the short run. It is possible that the stored gas might be sold during a critical contingency, rather than used for generation, but the analysis here suggests that TCC values the gas more than the other plants. Activity at the Taranaki plants over the critical contingency period is likely to be the same as it would have been under any elevated gas price.

24. In theory, if gas is priced slightly above the willingness to pay, the generator would curtail its generation. Figure 5 shows that, over the day, the price that generators are willing to pay for gas changes significantly. So a single gas price over this period might curtail gas consumption in some time periods but not others.

Figure 5 Willingness to pay for electricity by selected thermal plants



25. We note that the willingness to pay for gas is below the costs of additional gas purchased ($14.95/GJ) throughout the critical contingency (the only exception is that TCC is estimated to have a willingness to pay of $14.96/GJ at 18.30pm). The balancing gas price does not represent a suitable critical contingency price because, if gas was placed on the market at that price, the electricity generators would not be able to afford it. This would not be consistent with the requirements of the price setting exercise as set out in Sections 71 of the Regulations. Such a price would not allocate any gas to customers in the electricity market.

Requirements for Analysis

26. The Regulations require that a single critical contingency price is produced. Taking account of the willingness to pay for gas in different time periods (Figure 5), it needs to produce a result that is equivalent to that pictured in Figure 2. This is that:

    1. The costs of generation from all gas plants is greater than at the Huntly coal plant, as this limits the potential use of gas; and

    2. Electricity generation is restricted to the highest value users — only the CCGTs generate using gas.

27. The variable cost of generation at Huntly is estimated in Table 4 from the non-fuel variable costs, the fuel requirement and the fuel price, including the costs of CO_2 emission units. The price is estimated to be approximately $64/MWh, which is

below the wholesale electricity price at Huntly over the whole of the critical contingency (Figure 4), consistent with Huntly generating throughout that period (Figure 2). If Huntly coal is to bid ahead of all of the CCGTs, the price of gas needs to be higher than $7.60/GJ. At that price, TCC would have an incentive to use stored gas but would also be willing to purchase gas and generate.

Table 4 Costs of generation at Huntly and competitive gas prices

	Huntly	**Taranaki CC**	**Huntly e3P**	**Otahuhu B**
Heat rate (GJ/GWh)	10,900	7,760	7,400	7,240
Variable costs ($/MWh)	9.6	4.3	4.3	4.3
Coal price ($/GJ)	4.65			
Carbon cost ($/GJ)	0.35			
Price ($/MWh)	64.09	64.09	64.09	64.09
Fuel delivery costs ($/GJ)		0.10	0.60	1.00
WTP for gas ($/GJ)		7.60	7.48	7.26

Source: PB (2012) 2011 NZ Generation Data Update. Ministry of Economic Development; Coal price from: Denne T (2011) Coal Prices in New Zealand Markets: 2011 Update. Covec; Carbon cost assumes 89.4kg CO_2/GJ after oxidation (MED Energy Greenhouse Emissions 2011 web tables at: www.med.govt.nz/sectors-industries/energy/energy-modelling/publications/energy-greenhouse-gas-emission , a price of $7.80/t CO_2, which is a NZU spot price for the week to 9th March 2012 (OMF Carbon Markets Weekly Report 9 March 2012). In addition, obligations are only 1 emission unit for 2 tonnes of emissions, an effective price of $3.90/t

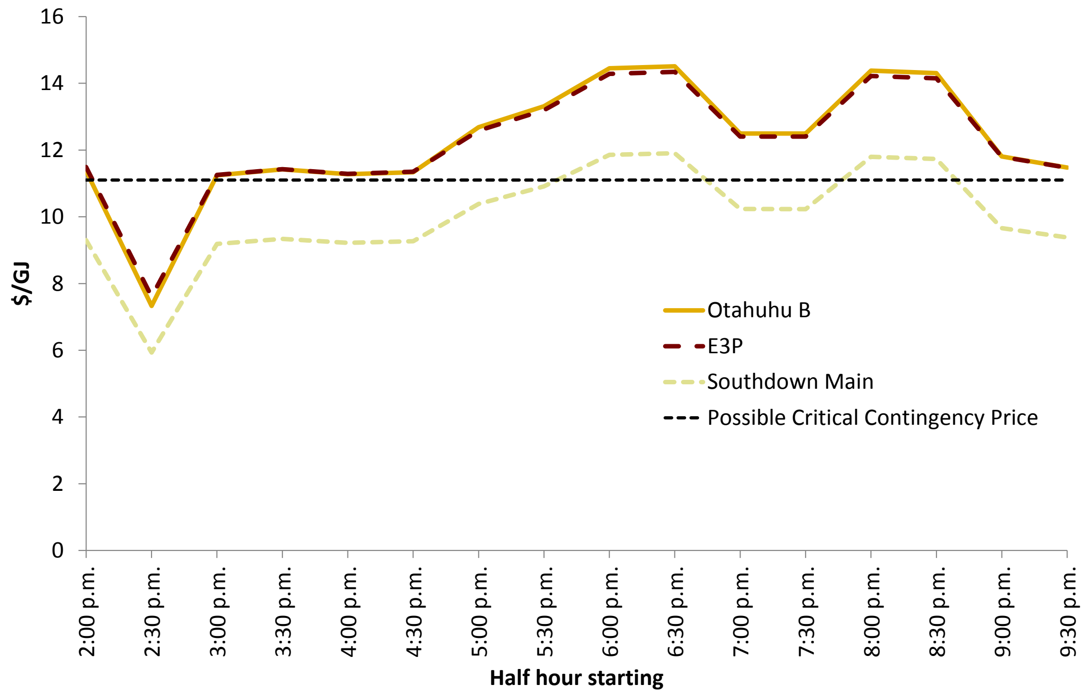
28. At this price of gas, the CCGTs would generate, but many other gas plants would also be willing to generate (Figure 5).

29. For the second criterion above, the price needs to be sufficiently high that no non-CCGT plant will generate, and low enough such that a CCGT plant will generate. In Figure 6 we show the period during which the electricity generators were curtailed and the estimated willingness to pay for gas by e3P and Otahuhu B, as the CCGTs that we expect to respond to the price signal. We ignore TCC in this assessment because levels of generation at that plant are determined by availability of gas in storage. In Figure 6 we also show the estimated willingness to pay for gas by the Southdown Main Station; if gas is to be used by the highest value users, as required under Section 71(2) of the Regulations, it needs to be higher than the willingness to pay of Southdown. On the chart we show a possible critical contingency price. It is a price at which:

- the CCGTs would be willing to pay for gas in all but one half hour (2.30pm), but they are unlikely to switch off given the time for ramping down and ramping up;

- it is too high for the non-CCGTs to generate at (Southdown main plant is the plant with the highest willingness to pay over the critical contingency), apart from four half-hour periods (6-6.30pm and 8-8.30pm) and we might expect Southdown not to ramp up for these short periods.

Figure 6 Possible Critical Contingency Price



30. Prices that would achieve this outcome are between $10.92 and $11.25/GJ, with a mid-point of approximately $11.10/GJ. As this price is higher than the price derived from the first criterion ($7.60/GJ), it becomes the binding criterion.

Critical Contingency Price

31. My determination is that the critical contingency price for the 3rd March 2012 is $11.10/GJ.