The Authority's decision on claim of an undesirable trading situation

Electric Kiwi's claim in relation to trading periods 35-40 on 2 June 2016

Final decision – 6 July 2016

Decision paper released: 16 August 2016

Final decision on claim of an undesirable trading situation in relation to trading periods 35-40 on 2 June 2016

This is the Authority's final decision under Part 5 of the Electricity Industry Participation Code 2010 (Code) regarding an alleged undesirable trading situation (UTS) in relation to trading periods 35-40 on 2 June 2016.

This decision has been taken by the Authority Board.

Summary of the situation

On 16 June 2016, Electric Kiwi Limited (Electric Kiwi) claimed that a UTS existed in relation to trading periods 35-40 on 2 June 2016. Electricity spot prices on 2 June exceeded $4,000 per megawatt hour (MWh) during trading period 36 (5:30-6:00pm) and reached around $3,000 per MWh during trading period 38 (6:30-7:00pm). The spot market normally trades at less than $100 per MWh.

Electric Kiwi's UTS claim relates to Meridian Energy Limited's (Meridian) offer behaviour while it was allegedly the pivotal generator during the relevant trading periods.

Undesirable trading situations

A UTS is defined in Part 1 of the Code as

> *"any situation-*
>
> *a) that threatens, or may threaten, confidence in, or the integrity of, the **wholesale market**; and*
>
> *b) that, in the reasonable opinion of the **Authority**, cannot satisfactorily be resolved by any other mechanism available under this Code (but for the purposes of this paragraph a proceeding for a breach of clause 13.5A is not to be regarded as another mechanism for satisfactory resolution of a situation)".*

The UTS provisions in the Code provide for circumstances where the Code cannot otherwise adequately deal with a situation that could have significant adverse consequences for the sustainability of the wholesale market.

The Authority's final decision

The Authority has considered Electric Kiwi's claim and has found that a UTS did not exist in relation to trading periods 35-40 on 2 June 2016 because there was no evidence that the existing levels of confidence in, or integrity of, the wholesale market were threatened, or may have been threatened, by the situation.

The reasons for this view are:

(a) Having considered a number of indicators of market activity, the Authority has not identified any discernible change that would suggest that the events of 2 June have impacted confidence in, or the integrity of, the wholesale market. Electric Kiwi is also the only market participant to have contacted the Authority with concerns about the situation on 2 June.

(b) The Authority considers the situation on 2 June was within the normal operation of the wholesale market, so does not threaten, or may threaten the existing level of confidence in, or the integrity of, the wholesale market. The situation was within the normal operation of the wholesale market because:

(i) Meridian's offer behaviour was not an unusual response for a market participant facing the risk of financial loss as a result of the tight and uncertain market conditions that existed in the North Island over the relevant trading periods. There is evidence that a similar approach is also used by other industry participants to manage the risk of financial loss when faced with similar scenarios of basis (or locational) price risk. That this type of offer behaviour has occurred regularly in the past, without creating a UTS, suggested that the behaviour alone was not sufficient to warrant a UTS finding.

(ii) The offering behaviour of other market participants, and an unscheduled generation outage, had equivalent impacts on the market outcomes to Meridian's offer behaviour.

(iii) Meridian may have relied on its offering strategy to manage the risks it was facing as a result of limitations in the risk management products available in the market.

Actions being taken as a result of the investigation

The Authority's investigation into this UTS claim has also identified other issues that it considers require further investigation. For example, notwithstanding the multiple factors that led to the high prices on 2 June, a key observation from the investigation of Electric Kiwi's UTS claim was that, if Meridian had kept its offers at original levels (holding all else equal), there would have been no price separation between the North and South Islands and final prices for the affected trading periods would have settled at significantly lower levels. In practice, the offering behaviour of other market participants, and an unscheduled generation outage, impacted on the actual market outcomes, and had equivalent impacts to Meridian's offer behaviour.

The Authority has initiated a market performance review[1] to investigate the issues that have been identified. This review will include further consideration of whether:

a) the trading behaviour, while not uncommon, was consistent with the Authority's statutory objective

b) the relevant Code provisions are achieving the intended outcomes

c) the risk management products available in the hedge market, including those in the financial transmission rights (FTR) market, are sufficient in their range and scope.

The outcome of the market performance review may identify potential improvements to the Code, trading arrangements, and the scope and availability of risk management products that result in a better functioning wholesale electricity market. Information on the market performance review and its progress will be made available as appropriate at http://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2016/high-energy-prices-2-june-2016//.

The Authority may also initiate the Code compliance process if it appears that a market participant may have breached any Code obligation during this or any similar event.

1 A market performance review represents the second stage of the Authority's structured approach to the monitoring of circumstances that have given rise to an out of the ordinary event. A review can proceed to an investigation depending on the extent of information gathering and analysis that is required. More information on the Authority's monitoring process is available at http://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/our-three-stage-process/.

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2.2 This document sets out the reasons for the Authority's decision that a UTS did not occur in relation to trading periods (TP) 35-40 on 2 June 2016.

2.3 This decision has been made by the Authority's Board: Brent Layton (Chair), David Bull, Susan Paterson, Roger Sowry and Elena Trout.

2.4 In responding to this claim, the Authority has followed its external and internal guidelines for processing UTS claims.[2]

3 Electric Kiwi claims a UTS exists in relation to TP 35-40 on 2 June 2016

3.1 On 2 June 2016, Electric Kiwi submitted a claim that a UTS existed in relation to TP 35-40. The claim is set out in the form attached as Appendix A.

3.2 Electric Kiwi's UTS claim related to Meridian's offer behaviour while it was allegedly the pivotal generator during the relevant trading periods. Electric Kiwi said:

> *"The fact that Meridian raised its offers to $5000 when it was net pivotal constitutes an undesirable trading situation…"* (at page four)
>
> *"Electric Kiwi submits that the final prices in TPs 36 and 38 were the result of Meridian's actions when it was pivotal and their actions constitute an undesirable trading situation."* (at page 11)
>
> *"…Meridian manipulated South Island prices during the North Island peak shortage of 2 June knowing that they were net pivotal and knowing that prices would be higher than would have been the case had they not been net pivotal and not changed their offers once they identified that situation."* (at page 12).

Electric Kiwi's requested actions to resolve the claimed UTS

3.3 Electric Kiwi's UTS claim asked the Authority to:

(a) find there was a UTS and take appropriate disciplinary action against Meridian 'in the hope that this acts as a deterrent and they are less likely to do it again'

(b) direct any trades be closed out or settled at a specified price as per clause 5.2(2)(b) of the Code.

4 Definition of undesirable trading situation

4.1 Undesirable trading situation is defined in clause 1.1 of the Code as:

"any situation-

*(a) that threatens, or may threaten, confidence in, or the integrity of, the **wholesale market**; and*

[2] The guidelines for participants are available at http://www.ea.govt.nz/code-and-compliance/uts/what-is-an-undesirable-trading-situation/.

(b) that, in the reasonable opinion of the ***Authority****, cannot satisfactorily be resolved by any other mechanism available under this Code (but for the purposes of this paragraph a proceeding for a breach of clause 13.5A is not to be regarded as another mechanism for satisfactory resolution of a situation)".*

4.2 The wholesale market is defined in clause 1.1 of the Code as:

"(a) the spot market for ***electricity****, including the processes for setting—*

(i) ***real time prices****:*

(ii) ***forecast prices*** *and* ***forecast reserve prices****:*

(iii) ***provisional prices*** *and* ***provisional reserve prices****:*

(iv) ***interim prices*** *and* ***interim reserve prices****:*

(v) ***final prices*** *and* ***final reserve prices****:*

(b) markets for ***ancillary services****:*

(c) the hedge market for ***electricity****, including the market for* ***FTRs****".*

4.3 Clause 5.1 of the Code provides that:

"(1) If the ***Authority*** *suspects or anticipates the development, or possible development, of an* ***undesirable trading situation****, the* ***Authority*** *may investigate the matter.*

(2) The following are examples of what the ***Authority*** *may consider to constitute an undesirable trading situation:*

(a) manipulative or attempted manipulative trading activity:

(b) conduct in relation to trading that is misleading or deceptive, or is likely to mislead or deceive:

(c) unwarranted speculation or an undesirable practice:

(d) material breach of any law:

(e) a situation that threatens orderly trading or proper settlement:

(f) any exceptional or unforeseen circumstance that is contrary to the public interest.

(3) To avoid doubt,—

(a) the list of examples in subclause (2) is not an exhaustive list, and does not prevent the ***Authority*** *from finding that an* ***undesirable trading situation*** *is developing or has developed in other circumstances; and*

(b) an example listed in subclause (2) does not constitute an ***undesirable trading situation*** *unless the example comes within the definition of that term in Part 1."*

4.4 Clause 5.2 of the Code provides that:

"(1) If the ***Authority*** *finds that an* ***undesirable trading situation*** *is developing or has developed, it may take any action that-*

(a) the ***Authority*** *considers necessary to correct the* ***undesirable trading situation****; and*

(b) *relates to an aspect of the electricity industry that the* ***Authority*** *could regulate in this Code under section 32 of the* ***Act****.*

(2) *The actions the* ***Authority*** *may take under subclause (1) include any one or more of the following:*

(a) *directing that an activity be suspended, limited, or stopped, either generally or for a specified period:*

(b) *directing that completion of trades be deferred for a specified period:*

(c) *directing that any trades be closed out or settled at a specified price:*

(d) *directing a* ***participant*** *to take any actions that will, in the* ***Authority's*** *opinion, correct or assist in overcoming the* ***undesirable trading situation****."*

4.5 Clause 5.5 of the Code provides that:

"The ***Authority*** *must attempt to correct every* ***undesirable trading situation*** *and, consistently with section 15 of the* ***Act****, restore the normal operation of the* ***wholesale*** *market as soon as possible."* [3]

4.6 For a situation to be categorised as a UTS it must meet the criteria set out in paragraphs (a) and (b) of the definition, as set out in paragraph 4.1. That is, it threatens, or may threaten, confidence in, or the integrity of, the wholesale market *and* it must not be able to be resolved by any other mechanism available under the Code. The definition also provides that a proceeding for a breach of the trading conduct provisions in clause 13.5A is not another mechanism for satisfactory resolution of a situation.

4.7 To be considered as "threatening", a situation must be such that it significantly affects participants' confidence in, or significantly affects the integrity of, the wholesale market.

4.8 Read together with clauses 5.5, which refers to the restoration of normal market operations after a UTS has occurred, a UTS must be a situation outside of the normal operation of the wholesale market and it must require the Authority to take some corrective action. If there would be no threat, or if the situation does not require corrective action, the situation is not a UTS.

4.9 A UTS may exist even if there is no Code breach, and a Code breach may occur without a UTS arising.

5 Statutory objective of the Authority

5.1 While the Code sets out the legal framework within which the Authority's consideration of a UTS must occur, the Authority's interpretation of its statutory objective provides an economic context.

5.2 The Authority's statutory objective in section 15 of the Electricity Industry Act 2010 (Act) provides as follows:

> *The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.*

[3] Section 15 of the Act sets out the Authority's statutory objective.

5.3 The Authority interprets its statutory objective as requiring it to exercise its functions set out in section 16 of the Act in ways that, *for the long-term benefit of electricity consumers*:

(a) facilitate or encourage increased competition in the markets for electricity and electricity-related services, taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in those markets (limb 1)

(b) encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total costs whilst being robust to adverse events (limb 2)

(c) increase the efficiency of the electricity industry, taking into account the transaction costs of market arrangements and the administration and compliance costs of regulation, and taking into account Commerce Act implications for the non-competitive parts of the electricity industry, particularly in regard to preserving efficient incentives for investment and innovation (limb 3).

5.4 In making its decision on Electric Kiwi's UTS claim the Authority has considered the Authority's statutory objective. In particular, the Authority has considered the economic rationale for UTS provisions generally, and considered how the UTS provisions in the Code relate to the three limbs of its statutory objective.

Economic rationale for UTS provisions

5.5 The economic rationale for UTS provisions is to achieve operationally efficient and competitive markets. In voluntary marketplaces, market providers strive to attract buyers and sellers by adopting rules that promote operationally efficient trading and rules aimed at giving buyers and sellers confidence in the market.

5.6 In particular, market providers adopt rules aimed at giving buyers confidence that suppliers' goods and services are what they say they are, contract terms are transparent and prices are competitively determined. Likewise, market providers adopt rules aimed at giving sellers confidence that buyers are genuine and will meet their payment terms. Undesirable practices by a few buyers and sellers harm other market users, and they also harm the market provider by deterring some parties from using the market.

5.7 UTS provisions are adopted by market providers because they cannot foresee all future eventualities and hence cater for these in the market's rules. Also, some practices are particularly difficult to specify in the rules, and so are better covered by generic UTS-type rules.

5.8 As market providers have strong incentives to enforce UTS provisions to further the efficient operation of the market and build confidence in it, UTS provisions often give broad discretion to market providers to deal with practices that threaten trading on the market in some manner, such as practices that disrupt orderly trading or the proper settlement of trades. Having the ability in certain circumstances to constrain the commercial decisions or actions of market participants is common to most organised markets.

Connection with the Authority's statutory objective

5.9 Based on the general economic rationale for UTS provisions given above, the UTS provisions in the Code are consistent with facilitating and encouraging competition (limb

1 of the Authority's statutory objective) and increasing the efficiency of the electricity industry (limb 3).

6 Chronology of the 2 June 2016 event

The North Island capacity position was tight and the potential for significant price separation between the South and North Island was signalled early in the day

6.1 National demand was relatively high due to cold weather. On 1 June, New Zealand total demand had reached 6,132 MW, the highest level to date in 2016 (and the highest since August 2015). Weather conditions on 2 June were similar, so similarly high levels of demand were expected.

6.2 Contact Energy Limited's (Contact's) Taranaki Combined Cycle plant (TCC), with 375 megawatt (MW) capacity, was not operating. TCC had not been operating during May 2016 or until 7 June 2016. Although TCC was not on outage[4], in previous winters Contact had made it clear that its combined cycle plants may not be available to run even if they are not on outage.

6.3 The system operator issued a warning notice at 13:14 on 2 June which:

(a) notified participants that there was potentially insufficient generation and reserve offers to meet demand and provide for N-1 security between 17:00 and 19:00 (TP35-38) in the North Island

(b) identified the cause as insufficient generation offers in the North Island

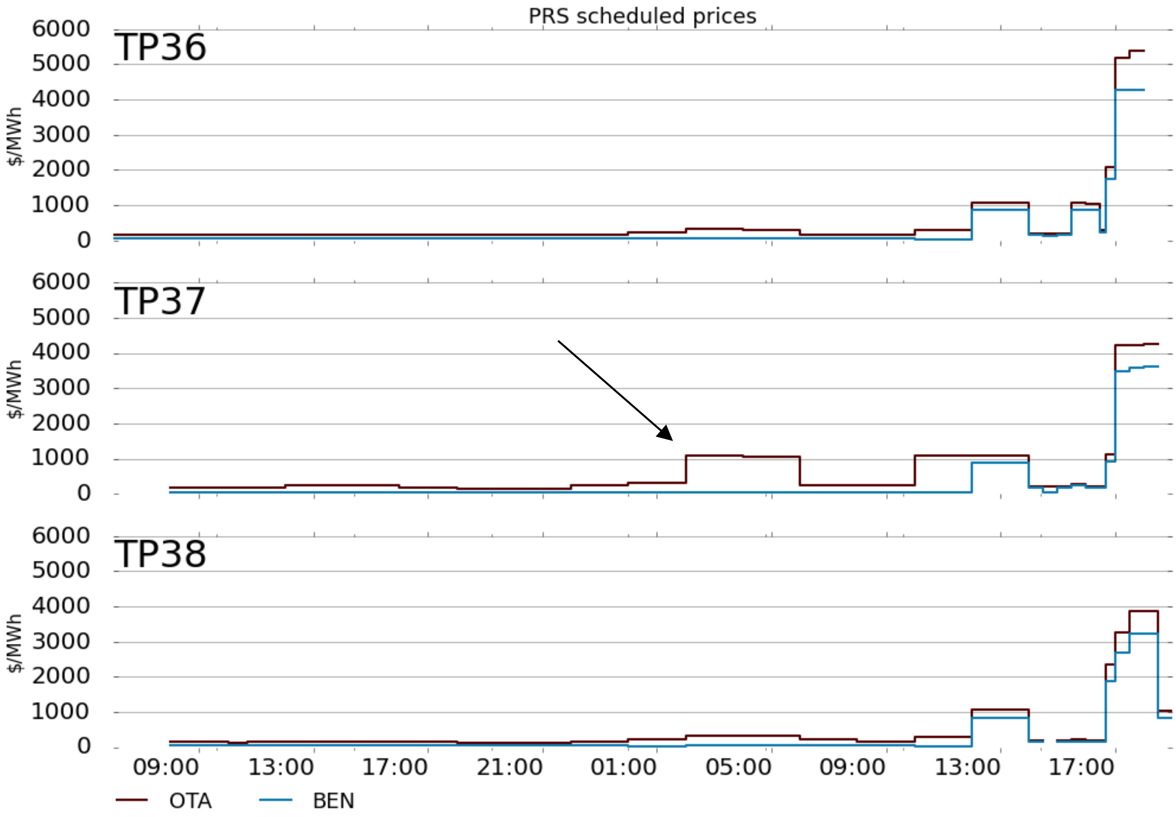
(c) requested participants to increase energy and reserve offers in the North Island.[5]

6.4 Figure 1, below, shows the price responsive schedule (PRS) prices for TP 36 to 38 on 2 June. The chart shows that the first sign of high prices was at about 02:00 on 2 June, where prices of $1,000/MWh were signalled in the PRS for TP 37 at Otahuhu (see arrow on Figure 1). High prices in all three trading periods and at both the Otahuhu and Benmore nodes were signalled in the PRS around midday, with very high prices not evident in the schedules until about 18:00.

4 According to the Planned Outage Co-ordination Process (POCP) website.

5 Available at http://www.systemoperator.co.nz/system-operations/notices/formal-notices.

Figure 1: PRS scheduled prices for Otahuhu and Benmore



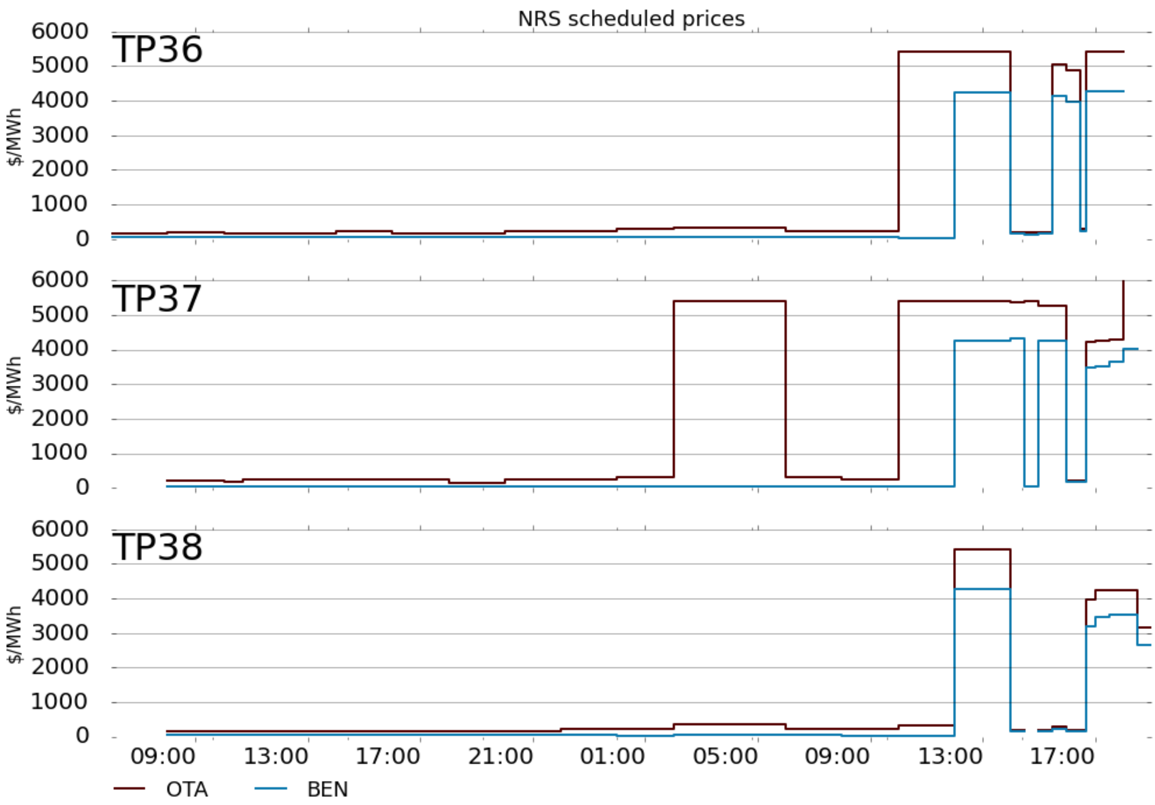
Source: Electricity Authority

6.5 Figure 2 shows the non-responsive schedule (NRS) for TP 36 to TP38, on 2 June. As the NRS does not include the responses of load to price through nominated bids, it shows more price separation than the PRS. Meridian has said that it uses the NRS in situations such as those that existed on 2 June because it finds the PRS[6] to be insufficiently reliable for use as a primary forecasting tool in these circumstances.[7] Electric Kiwi's UTS claim also used the NRS to demonstrate the situation as it saw it unfold on 2 June.

6 The PRS resulted from the Authority's demand-side bidding and forecasting project (DSBF). A post-implementation review of the DSBF initiative is expected to be published in early September 2016. The review will present evidence which shows that the PRS produces superior price forecasts to the NRS.

7 See footnote 2 in Meridian's response to the Authority's questions in relation to the event, attached as Appendix B.

Figure 2: NRS scheduled prices for Otahuhu and Benmore



Source: Electricity Authority

The sequence of events shows that Meridian changed its offers relatively early compared to other generators, and did not set final prices

6.6 Table 1 shows the chronology of the main trading and market events that occurred on 2 June in relation to TP 36-38. Table 1 is based on the information available from the relevant NRS and PRS schedules. Those schedules were not published at the exact times shown in Table 1—the times have been rounded in order to simplify the presentation of the information. In practice, the offer changes identified will have occurred between the times shown (they will have occurred between, and probably in response to, the publishing of the relevant schedules).

6.7 Meridian's offer changes are indicated in the columns with the header 'MERI'. Only Meridian's main offer changes are included—minor changes have been excluded as they are numerous.

6.8 During the investigation of Electric Kiwi's UTS claim it was identified that other participants had also changed their offers for these trading periods prior to gate closure (and after Meridian's main offer changes). The main offer changes from Contact ('CTCT' in the table) and Genesis Energy Limited (Genesis) ('GENE' in the table) are also shown in the table, as these offer changes also influenced the prices being calculated in the schedules. The column 'Other' provides commentary on where the main offer changes occurred, and on other events that occurred prior to dispatch.

Table 1: Sequence of main events on 2 June 2016

Source: Electricity Authority

Time	36 MERI	36 CTCT	36 GENE	37 MERI	37 CTCT	37 GENE	38 MERI	38 CTCT	38 GENE	Other
02/06/2016 02:00	Price separation apparent in NRSL									
02/06/2016 10:00	Price separation apparent in NRSL again						Price separation apparent in NRSL			
02/06/2016 11:00							191 MW moved to $975 from lower priced bands			
02/06/2016 11:30	205 MW shifted to $4,248 from $275-$975 bands			321 MW shifted to $4,248 from $275-$975			316 MW shifted to $4,248 from $275-$975.			Meridian’s main offer changes
02/06/2016 12:00		52MW shifted from $220 to $5,000			52MW shifted from $220 to $5,000			52MW shifted from $220 to $5,000		Contact’s main offer changes

	36			37			38			
Time	**MERI**	**CTCT**	**GENE**	**MERI**	**CTCT**	**GENE**	**MERI**	**CTCT**	**GENE**	**Other**
02/06/2016 15:00	Series of changes result in 248MW at >$4,200 by 15:30		62MW shifted from $185 to $4,600	Series of changes result in 335MW at $4,000 or above by 15:30						Genesis Energy's main offer changes for TP36
02/06/2016 15:30					156MW shifted from ca. $5,000 to $3,900			156MW shifted from ca. $5,000 to $3,900		
02/06/2016 16:00							Series of changes result in 331MW at >$4,200 by 16:30	52MW shifted from $3,900 to $3,000	62MW shifted from $185 to $4,600	Genesis Energy's main offer changes for TP38
02/06/2016 16:30										Mangahao (29 MW) trips and does not generate for the rest of the day

6.9 The chronology in Table 1 shows that Meridian's main offer changes were submitted at 11:33 (as also shown in Figure 10-Figure 12). At 12:07 Contact increased its offers for its Whirinaki diesel turbine generator from $220/MWh to $5,000/MWh for TP 36-38 (17:30-19:00). At 15:15, Genesis moved 62 MW of hydro at Waikaremoana from $185/MWh to $4,600/MWh for TP 36. Genesis made a similar offer change at 16:24 for TP38.

6.10 Genesis did not change its offers at Waikaremoana for TP37 and this 62 MW block (offered at $185/MWh) ultimately set the prices for that period in both the North and South Islands.

6.11 The Waikaremoana block, at the higher offer price, set the price in TP36 in both the North and South Islands. The revised Whirinaki offer set the price in TP38 in both the North and South Islands.

Mangahao tripped on start-up at 16:37 and didn't run for the rest of the afternoon

6.12 King Country Energy Limited's Mangahao hydro station tripped at 16:37 and did not run for the rest of the afternoon. As Mangahao is an embedded generator, it is subject to half hour gate closure so it only had to provide its *bona fide* physical reason for cancelling its offer for one trading period. This trip resulted in a loss of 29 MW of supply in the North Island. As set out at paragraph 8.24, prices were extremely sensitive to demand changes for TP 36-38, so the loss of 29 MW was significant factor in determining prices in both the North and South Islands. The previous day Mangahao generated the entire day at 29 MW.

7 Market indicators and feedback indicate that confidence in, and the integrity of, the wholesale market has not been adversely affected

7.1 If the situation of 2 June had threatened, or may have threatened, confidence in, or the integrity of, the wholesale market, it should have been possible to observe this through other indicators of market activity. For example, by observing whether the situation "stressed" the market through increased prudential requirements, or whether there had been a material change in the trading of risk management products such as financial transmission rights (FTRs) and ASX New Zealand Electricity futures.

There has been no observable impact on wholesale market positions

7.2 In order to participate in the wholesale electricity market, industry participants are required to provide prudential security to the clearing manager to cover that participant's net exposure to wholesale prices over the next 55-60 days.[8] Prudential requirements are calculated daily by the clearing manager.

7.3 Participants' prudential requirements over the weeks before and after the event were consistent with normal operations. There was no indication that the situation of 2 June caused an unusual increase in prudential requirements for any participant, or that any participants had made any significant changes to their market positions. In other words, there was no evidence from participants' prudential requirements that confidence in, or

8 This prudential security can take many forms, including cash deposits, bank guarantees, third party guarantees from a party with an acceptable credit rating, bonds from a surety with an acceptable credit rating, and/or hedge contracts lodged with and settled by the clearing manager. See http://www.ea.govt.nz/operations/market-operation-service-providers/clearing-manager/prudential-security/ for more information.

the integrity of, the wholesale market[9] had been affected by the 2 June event. More information on the situation with prudential requirements is provided in Appendix D.

7.4 The clearing manager advised the Authority that there had been no contact from participants expressing concern about prudential requirements in relation to 2 June, or the situation on 2 June more generally.

7.5 This can be compared to the 26 March 2011 UTS, where a number of parties claimed significant financial impacts.

No parties have raised concerns with the system operator

7.6 The system operator advised that it had had no contact from any parties in relation to the events of 2 June.

There has been no observable impact on FTR trading

7.7 FTRs are financial hedges that help protect energy purchasers or generators from price uncertainty caused by transmission losses and constraints. FTR products are offered at five locations on the grid (hubs) for a duration of one calendar month.[10] Trading in FTRs can provide an indication of market perceptions of price uncertainty on the transmission system.

7.8 FTR auctions for June 2018 were completed mid-month in April, May and June 2016. Analysis shows the bidding behaviour in June was reasonably consistent with the bidding behaviour in the April and May auctions. This indicates that FTR participants did not expect there would be out-of-the-ordinary price separation in June 2018, ie, the auction results did not suggest that participants now expected greater degrees of price separation to occur in the future as a result of the situation on 2 June. More information on the situation with FTR trading for 2018 is provided in Table 3.

7.9 There were also FTR auctions for the June 2016 period conducted in April and May 2016. Analysis of these auctions showed reasonably consistent behaviour from April to May and did not indicate anything unusual or indicate any participant knew in advance there would be out-of-the-ordinary price separation in June 2016.

7.10 In summary, there was no evidence from FTR trading of confidence in, or the integrity of, the wholesale market being affected by the 2 June event.

7.11 Because there was no FTR market in 2011, it was not possible to compare the market response to the 2 June event to that for the 26 March 2011 UTS.

There has been no observable impact on ASX trading

7.12 The Australian Securities Exchange (ASX) New Zealand Electricity futures and options market provides a mechanism for companies with an interest in or exposure to the New Zealand electricity market to trade standardised and centrally cleared financial contracts that can assist them to manage the associated electricity market financial risks.[11] Trading on the ASX can provide an indication of market confidence in spot price outcomes.

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9 The Authority's consideration of the impacts of the situation on the integrity of the wholesale market includes consideration of any impairment to wholesale market activity and processes (ie, did the wholesale market continue to operate in a 'normal' manner?)

10 See https://www.ftr.co.nz/ for more information in the FTR market.

11 See http://www.asx.com.au/products/energy-derivatives/new-zealand-electricity.htm for more information on the ASX New Zealand Electricity futures and options market.

7.13 The Authority analysed trading activity on the ASX New Zealand Electricity futures and options market leading up to and following 2 June. The bid/ask spreads and daily settlement prices, as measured at the end of the trading day, and the number of contracts transacted each day showed no material divergences from expected patterns. This suggests that ASX market participants were not expecting imminent price spikes to occur at Otahuhu or Benmore.

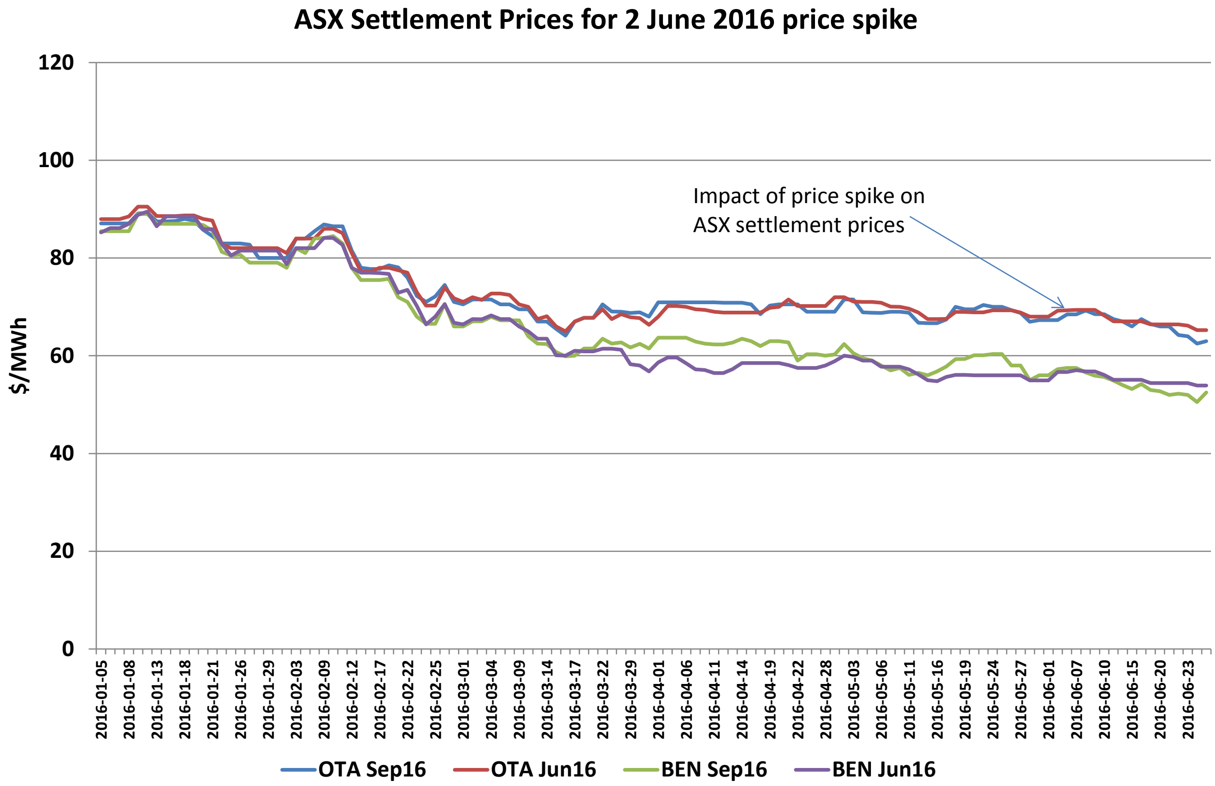
7.14 This conclusion was supported by the interaction of both ASX quarterly and monthly baseload products along with June's FTR daily settlement prices. The spot price differences between Benmore and Otahuhu, ASX settlement prices, and resulting implicit spot price differences for the remainder of the quarter and month, were reflective of the good hydro storage conditions that existed at the time, and did not suggest participants had concerns about unusual pricing.

7.15 The ASX daily settlement prices for both the June 16 monthly and quarterly contracts reflected very similar implicit spot price differences between Benmore and Otahuhu for pricing over the period to the end of June, which suggested that participants were trading with a good level of confidence in the market. As with the FTR market, there was no evidence of confidence in, or the integrity of, the wholesale market having been affected by the 2 June event.

7.16 A comparison of recent ASX settlement prices with those that followed the 26 March 2011 UTS highlighted that the 2 June event had a negligible, if any, impact on market activity (where market trading activity was considered a proxy for confidence in, and the integrity of, the wholesale market).

7.17 Figure 3 below shows ASX settlement prices for Otahuhu (OTA) and Benmore (BEN) for the June 2016 (Jun16) and September 2016 (Sep16) quarters before and after 2 June. No discernible impact from the 2 June event was observable in the OTA Sep16 or BEN Sep16 settlement prices—traders on the ASX were not 'pricing in' any new information about risk over the remainder of winter 2016.

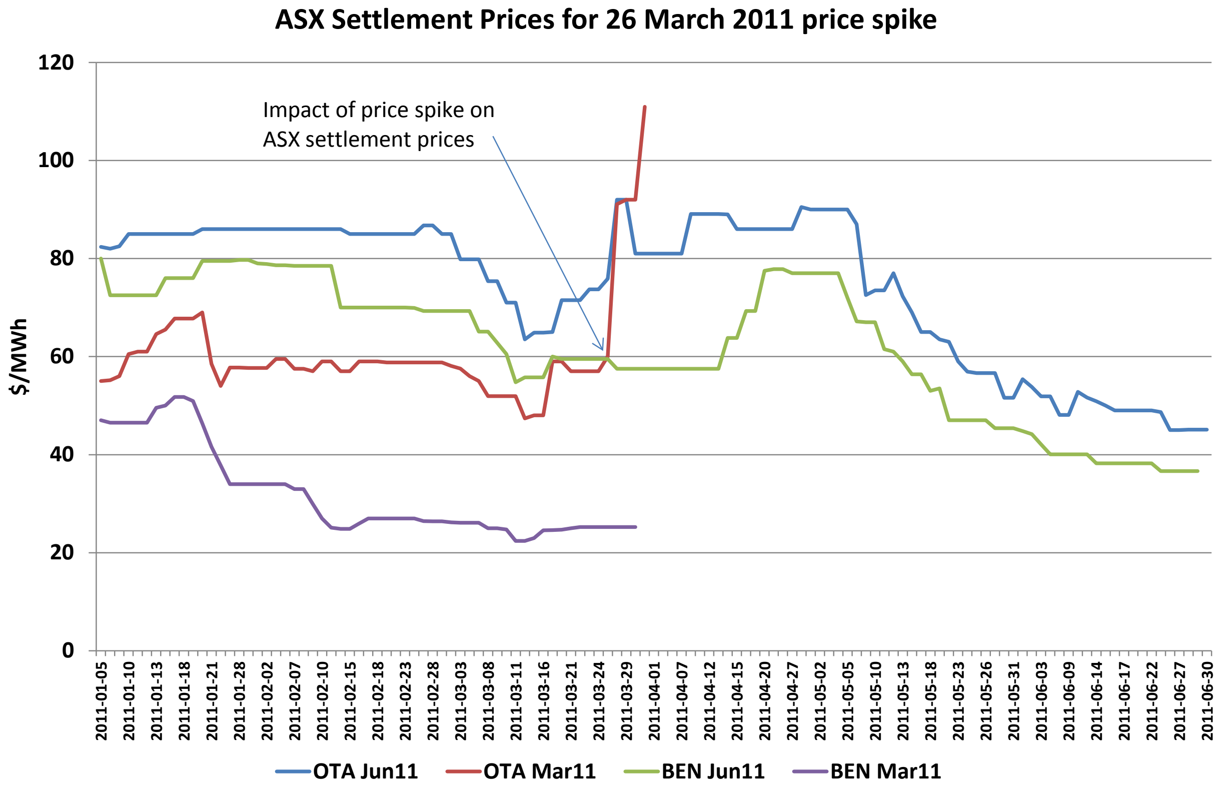
Figure 3: Recent ASX settlement prices



Source: Electricity Authority

7.18 In comparison, the 26 March 2011 UTS caused a clear and significant increase in adjacent ASX futures contracts. Figure 4 below shows settlement prices for Otahuhu in the quarter immediately following that event. The sharp increase in the OTA Jun11 settlement price (blue line) indicated a heightened risk perception due to new information regarding generator behaviour. This outcome is consistent with a loss of confidence in spot market outcomes.

Figure 4: ASX settlement prices around the 26 March 2011 UTS



Source: Electricity Authority

7.19 In summary, the indicators in the ASX market did not show anything unusual for the 2 June 2016 event, especially in comparison to the 26 March 2011 UTS. More information on the situation with ASX trading is provided in Appendix D.

No other parties have contacted the Authority to raise concerns

7.20 No parties, other than Electric Kiwi, contacted the Authority expressing concerns about the 2 June event.

The response of participants is a valid indicator of confidence and integrity

7.21 The High Court's judgment on the appeal against the Authority's decision on the 26 March 2011 UTS includes some discussion on the appropriateness of feedback from participants as a measure of confidence and integrity. Paragraph [207] of that decision notes that "*While the Authority did not have to accept what the complainants were saying, this was powerful evidence of an actual loss of confidence (accepting many of the complainants had "lost" as a result of events of 26 March).*"[12]

7.22 Accordingly, in considering whether confidence in, or the integrity of, the wholesale market has been affected by the 2 June event, the Authority noted the absence of any feedback or complaints, beyond that of Electric Kiwi submitting its UTS claim.

12 BOPE and others v. The Electricity Authority, [2012] NZHC 238. The Authority's ability to consider participant feedback is discussed in paragraphs [202] to [209].

8 The observed prices were influenced by the level of demand, Meridian's offers, other parties' offers, and scarcity of North Island reserves

High-level summary of the events on 2 June 2016

8.1 The following is a high-level summary of the situation that existed on 2 June:

Demand

(a) Demand was high, but not as high as the day before when prices were normal (refer paragraph 6.1).

(b) Some demand response appeared to have occurred in response to the forecast high prices (paragraphs 8.4-8.5).

(c) Owing to the steepness of the offer curve, prices would have been sensitive to small changes in demand and reserve offers (paragraphs 8.6-8.8).

Offers

(d) High prices were signalled in the pre-dispatch schedules as early as 01:00 on 2 June (paragraphs 6.4-6.5).[13]

(e) The system operator requested an increase in energy and reserve offers as there was the potential that insufficient offers would be available to meet demand in the North Island and provide security for a contingent event (paragraph 6.3).

(f) Meridian was not the only participant to change its offers before gate closure. Genesis (at Waikaremoana) and Contact (at Whirinaki) also moved tranches into higher price bands (paragraph 6.8).

(g) Norske Skog Tasman (NZ) Limited (Norske Skog) and Pan Pacific Forest Products Limited (PanPac) also appeared to have reduced their demand in response to forecast high prices, with consequential reductions in their reserve offers (paragraphs 8.21-8.22).

Prices

(h) High prices occurred in final prices in both the South and North Islands for TP 36 and TP 38, but were at normal levels in TP 37 (paragraphs 8.2-8.3).

(i) Forecast prices changed significantly after gate closure in TP36 and 38 as a result of offer changes made immediately before gate closure (by parties other than Meridian) and changes to the demand forecast (which becomes more accurate close to real time).

(j) The price setter was Genesis at Waikaremoana (TP36-37) and Contact at Whirinaki (TP38) (paragraphs 6.9-6.10).

(k) The final price in TP37 was at a normal level, despite being forecast to be high right up to gate closure, demonstrating how sensitive prices were to demand.

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13 As shown in **Error! Reference source not found.**Figure 1 and Figure 2**Error! Reference source not found.**, high prices were not forecast in every schedule, and there was some oscillation between high and much lower (ca. $200-$300/MWh) prices between schedules. The presence of the high prices, and the oscillation to the much lower prices, would likely have signaled to participants that the final outcome was very uncertain.

(l) Final North Island energy prices were consistent with a situation where there is a known shortage of generation, and with potential prices observable in the schedules several hours ahead of dispatch.

(m) Final South Island energy prices were largely influenced by Meridian's offer strategy, despite Meridian not technically being the marginal price setter.

(n) Any one of the following four perturbations would have resulted in a significantly different outcome:

(i) Had Meridian not revised its energy offers in the preceding six hours before real-time for TP 36 and TP 38 (holding all else constant), final prices in both the South and North Islands would have been substantially lower (paragraphs 8.17-8.18).[14]

(ii) Had Contact or Genesis not revised their energy offers in the hours before real-time (holding all else constant), final prices in both the South and North Islands for TP 36 and TP 38 would have been substantially lower (paragraphs 8.24-8.25).

(iii) If Mangahao had not tripped prior to dispatch, final prices in both the South and North Islands for TP 36 and TP38 would have been substantially lower (holding all else constant) (paragraphs 8.24-8.25).

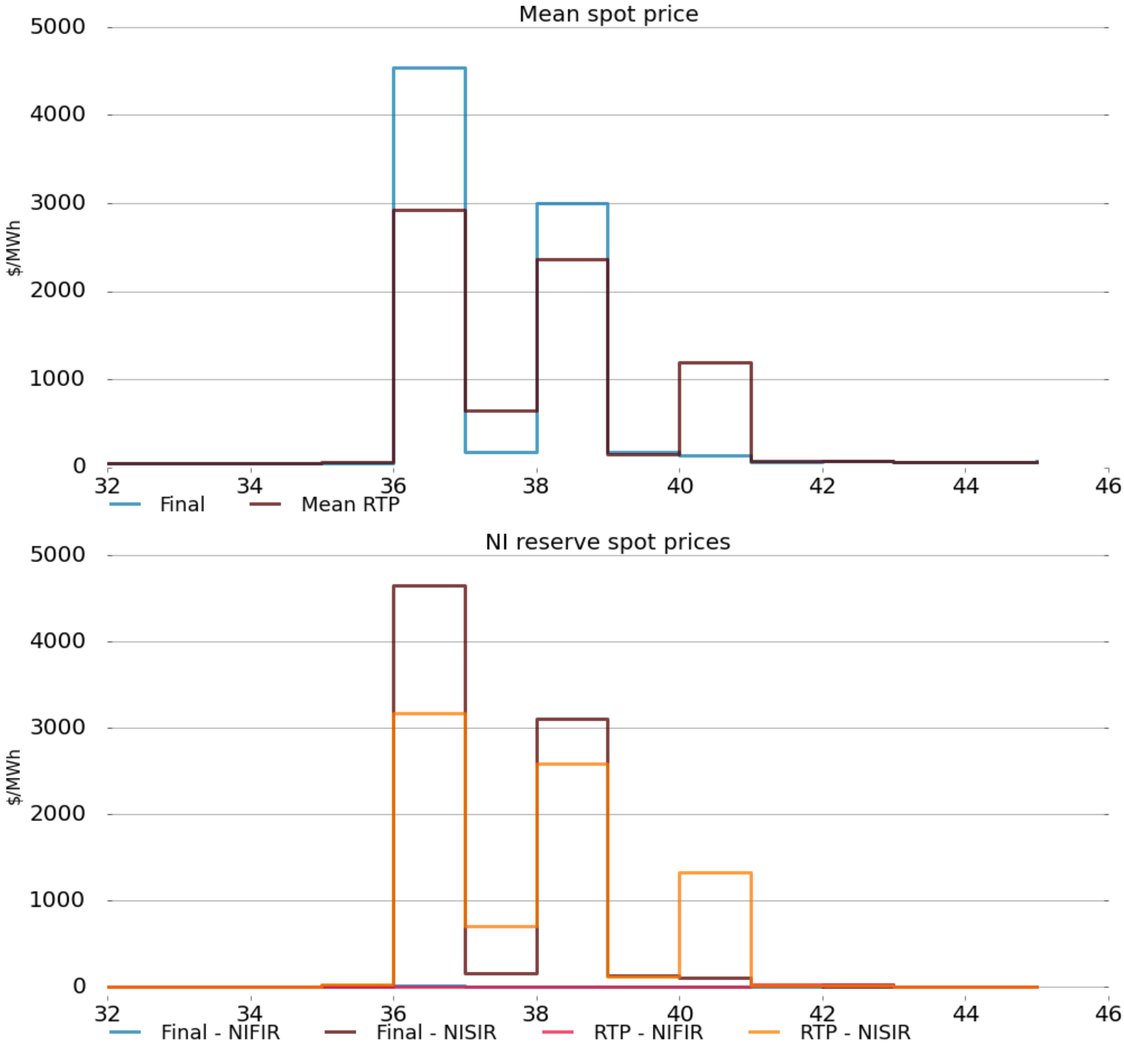
Market outcomes and analysis

8.2 Figure 5 shows final prices for energy and reserves as well as the real time prices (RTP, also known as five-minute prices) for energy and reserves. The top chart shows mean energy prices (ie, the average of all pricing nodes across New Zealand). Final prices 'spiked' across the country in TP 36 and TP 38 (yellow line). The bottom chart shows North Island sustained instantaneous reserve (NISIR) prices over the same period. Final NISIR prices (blue line) also spiked in the same periods as the energy spikes due to the interaction between the reserve and energy markets.

8.3 Prices in other TPs were at normal levels.

[14] Their offers were made using imperfect information about the actual conditions at dispatch. Meridian made these offers using forecasts of demand and HVDC transfer that were unlikely to be accurate in practice (and that, on the day, were highly sensitive to demand).

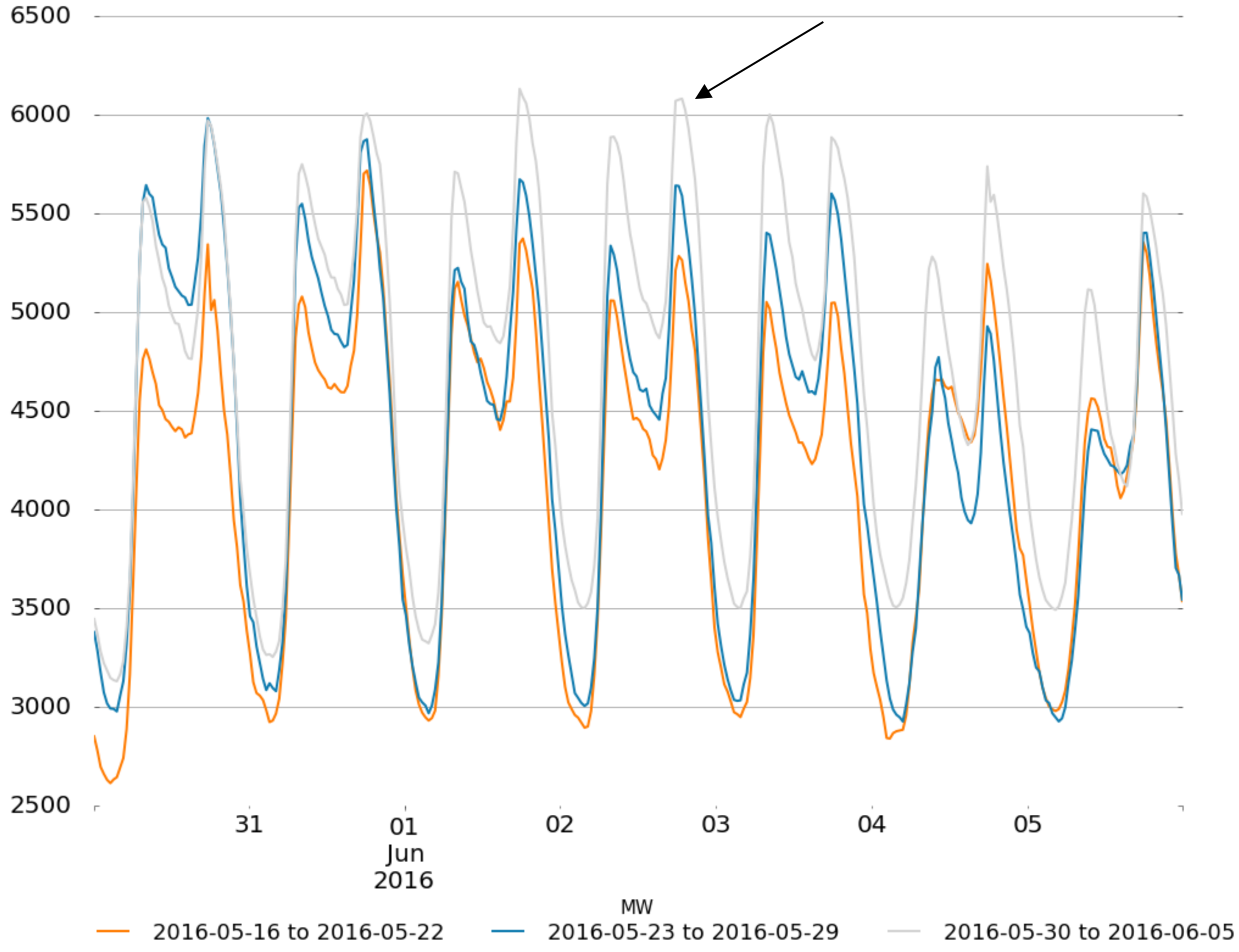
Figure 5: Final and real time energy and reserve prices for 2 June 2016



Source: Electricity Authority

8.4 Figure 6 shows total demand (in MW) for the three days before and after 2 June (grey line), as well as the previous two weeks. The data for the previous two weeks has been shifted by seven and 14 days respectively so that the days of the week are aligned for comparison purposes.

Figure 6: National demand over 30 May 2016 to 6 June 2016



Source: Electricity Authority

8.5 Relative to prior periods, demand was high on 2 June (see arrow on Figure 2), but not as high as 1 June 2016. The shape of the peak on 2 June appeared to be slightly truncated compared to the other days (ie, it had a flatter 'peak') and it is possible that the forecast high prices resulted in reduced demand.

Simulation shows how sensitive price was to changes in demand

8.6 Analysis was undertaken of what would have happened had demand been slightly different. The analysis suggested it was the price of the offers rather than the quantity of offers that caused the high prices (see the analysis presented in C.1-C.6 of Appendix C).

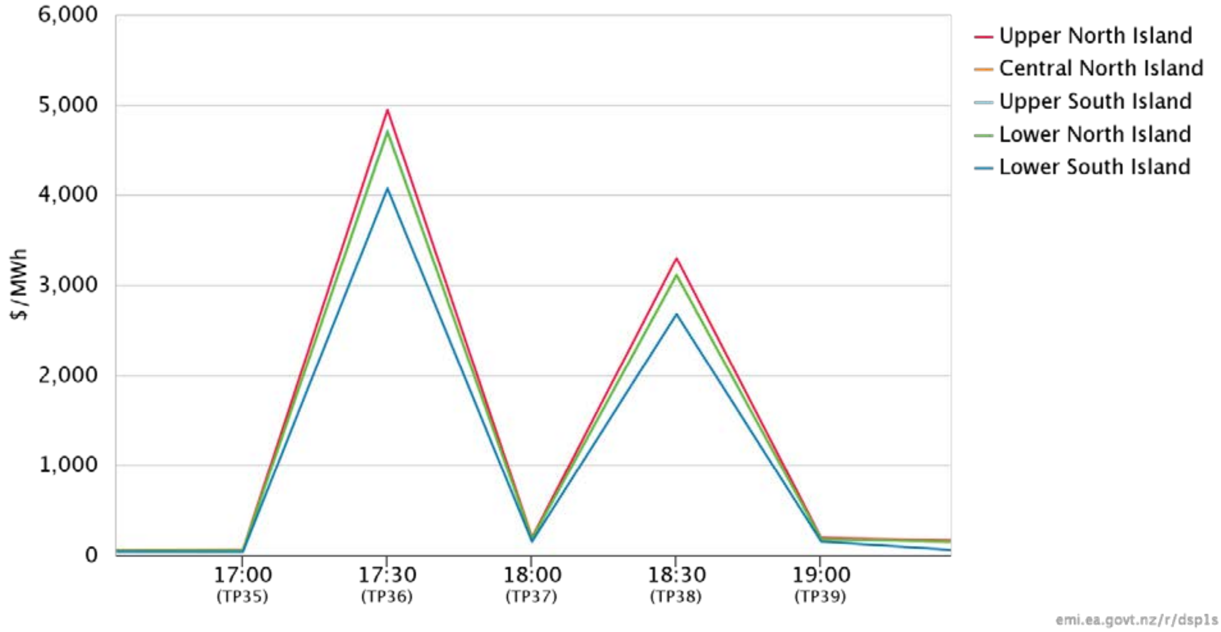
8.7 A large effect on prices can be seen in TP 36 with just a 0.1 per cent reduction in North Island demand. TP 38 has a similar large fall in price with a 0.5 per cent reduction in North Island demand.

8.8 There would have been a large increase in price in TP 37 if New Zealand total demand had been 0.8 per cent higher. Again, this shows how sensitive the prices were to changes in demand.

The energy and reserve market conditions combined to produce high prices

8.9 In TP 36, the marginal generation offer was $4,600/MWh from Genesis' Waikaremoana hydro scheme. This offer effectively set the energy price for the entire country, with the only differences in the prices between nodes being due to marginal loss effects (see Figure 7, below).

Figure 7: Various nodal prices on 2 June 2016



Source: Electricity Authority

8.10 The Authority determined that Waikaremoana was the marginal generator by performing a vSPD[15] experiment with a one MW increment in demand at a North Island node and observing that Waikaremoana was the only generation offer whose cleared quantity was different to the base case.[16]

8.11 In early June, Waikaremoana storage was sitting at around only 30 per cent of average for the time of year. The decision to offer a significant portion of Waikaremoana generation at $4,600/MWh appears broadly consistent with this situation. However, in this instance, 62 MW of generation at Waikaremoana was only moved up into this price tranche just before gate closure.

8.12 In TP 38, the marginal generation offer was $3,000/MWh from Contact's Whirinaki diesel turbine station. Again, this offer effectively set the energy price for the entire country. Even though Whirinaki was not dispatched in TP 38 (due to system operator discretion)[17] it was nevertheless cleared in final pricing, and thus set final prices.

8.13 The Authority performed a similar vSPD experiment to determine what was setting the NISIR price. The sum of energy, instantaneous reserve (IR) and frequency keeping cleared at a generation plant cannot exceed the available capacity. In this case, the

15 The vSPD (vectorised Scheduling, Pricing and Dispatch) model has been developed by the Authority as a precise replica of the dispatch tool applied by the system operator for its real time decision making (SPD).

16 While the vSPD analysis shows that it was the North Island generators that set final prices for TP 36 to 38, a hypothetical example presented in Appendix E highlights how a generator can significantly influence prices without technically 'setting' prices.

17 The system operator has advised that the schedules were showing that Whirinaki would only be required for one 5-minute dispatch period. The plant needs several minutes to commence operation, and to be shut down, so it was considered to be inefficient for the generator to be dispatched in practice.

marginal SIR offer was at one of Contact's Stratford peaking gas turbine units. But in order to supply an additional MW of SIR, the cleared energy at Stratford had to reduce by 1 MW, which then had to be made up by the marginal energy offer – Waikaremoana in TP 36 and Whirinaki in TP 38. So, although the SIR offer price at Stratford was only $1/MWh, the SIR price became linked to the marginal energy offer, resulting in NI SIR prices of $4,646/MWh and $3,103/MWh respectively in the two trading periods.

8.14 The level of HVDC injection into the North Island is limited by the availability of North Island IR. So, once the HVDC transfer is at a level where it becomes the binding risk, any further increase in HVDC transfer would require additional North Island IR.

8.15 Sufficient North Island generating capacity must be offered to meet both the energy (where this is not supplied by the HVDC) and the IR (where this is not supplied by interruptible load) requirements. When supply becomes tight, generating plants often have to reduce their energy output to free up capacity for IR, and both energy and IR prices can reach high levels. The analysis described above shows that this was the case in TP 36 and 38 on 2 June.

8.16 Under these conditions, any increase in HVDC transfer above the binding risk level would require a decrease in North Island generation to free up IR capacity. Once all North Island generating capacity has been utilised for either energy or IR, no additional North Island demand can be supplied.

8.17 It transpired that in TP 36 and TP 38 the HVDC transfer was below the binding risk level by approximately 109 MW and 51 MW respectively. Meridian's lower pre-dispatch offers would have increased HVDC transfer sufficiently to bring prices back to less than $300/MWh, but without the HVDC risk becoming binding. The effect of reversing Meridian's offer changes is explained in C.12- C.14 of Appendix C.

8.18 When considering this analysis, it is relevant to note that Meridian's main offer changes were made well in advance of dispatch, and so will have relied on imperfect information.[18] Other participants also made offer changes after Meridian's main offer changes.

Small increases in quantity of North Island reserves would have substantially lowered prices

8.19 A simulation was undertaken to investigate what might have happened to final prices if there was more North Island reserve available. This simulation involved increasing the amount of Net Free Reserve (NFR) available in the North Island, which is equivalent to adding additional low priced reserve into the North Island, ie, one MW of additional North Island NFR is equivalent to offering one additional MW of North Island reserve at a price of $0. The analysis is presented in C.7 - C.9 of Appendix C.

8.20 As discussed above, extra reserves would tend to lower both reserve and energy prices because of the inter-relationship between the energy and reserve prices. The simulation showed that extra reserves of approximately 5-10 MW (TP36) and 15-20 MW (TP38) would have brought prices down to a similar level to those seen in TP37 (all other things being equal).

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18 Meridian's last offer changes were made approximately 3 hours, 3.5 hours and 2.5 hours ahead of dispatch for trading periods 36, 37 and 38 respectively.

While interruptible load (IL) reserve offers were withdrawn after gate closure, the net effect was likely positive

8.21 Analysis of changes in reserve offers (presented in C.10-C.11 of Appendix C) indicated that NISIR offers were reduced within the two-hour window between gate closure and real-time. Given the size of the offer changes, some *bona fide* reasons for the changes would have been expected.

8.22 Based on the Authority's assessment of the 2-hour rule revision data provided to the Authority, Norske Skog and Pan Pac appeared to have reduced their demand over TP35-39. A load reduction should also be accompanied by a reduction in reserve offers (since there is now reduced load available to be dispatched as reserve). It appeared that the *bona fide* load reduction by Pan Pac, and Norske Skog's reduction in demand through its dispatchable demand offer, broadly matched the observed reduction in reserve offers. This implies that the reduction in reserve offers after gate closure was due to physical reasons and not through gaming of the reserve market.

Offer changes made by other participants after Meridian's offer changes, and the Mangahao generator outage, may have had an equivalent impact on prices

8.23 Electric Kiwi's UTS claim includes the following allegation:

> *"Electric Kiwi submits that the final prices in TPs 36 and 38 were the result of Meridian's actions when it was pivotal and their actions constitute an undesirable trading situation."*

8.24 The Authority analysed the offer changes made by Genesis and Contact after Meridian's main offer change, and the Mangahao outage, to determine what impact these changes may have had on final prices. The analysis presented in Table 2 shows the prices that would have resulted if those offer changes (including the Mangahao outage) had not been made. The analysis involved 'backing out' each change from the offer stack in turn. Each offer change was analysed separately, and by itself. The modelled changes were:

(a) 62 MW of Genesis' Waikaremoana offers:

  (i) for TP36, offer reversed from $4600 back to $185 (ie, reversal of 15:15 offer change)

  (ii) for TP38, offer reversed from $3500 back to $185 (ie, reversal of 16:24 offer change)

(b) 52 MW of Contact's Whirinaki offers:

  (i) for TP36-38, offer reversed from $4995 back to $220 (ie, reversal of 12:07 offer change)

(c) 29 MW of Mangahao offers:

  (i) for TP36-38, reinserted offers at 1 cent (ie, reversal of 16:37 *bona fide*).

Table 2: Impact of other parties offer changes on final prices

	Modelled final prices ($ per MWh)					
Trading period	36			38		
Price	HAY	BEN	NISIR	HAY	BEN	NISIR
Base case	$4,605	$4,236	$4,647	$3,048	$2,792	$3,104
Genesis changes removed (only)	$191	$176	$158	$197	$143	$198
Contact changes removed (only)	$218	$201	$186	$224	$161	$225
Mangahao outage removed (only)	$256	$235	$224	$224	$161	$227

Source: Electricity Authority

Notes: 1. HAY is Haywards, BEN is Benmore and NISIR is North Island sustained instantaneous reserves

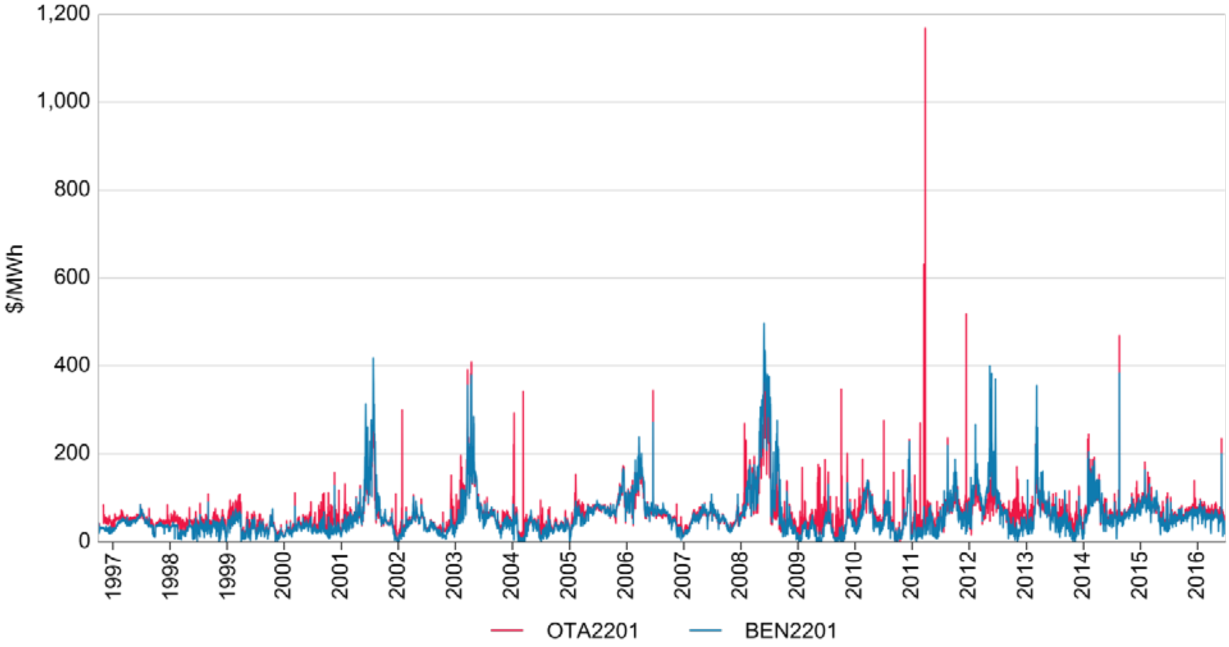
8.25 The analysis showed that, if any of these other parties' offer changes had not occurred, the final price for TP 36 and 38 would have been similar to that for TP 37 (all other things being equal). It was therefore not possible to identify Meridian's actions as being solely responsible for causing the high energy prices observed in TP 36 and TP 38.

The prices in TP 36 and 38 are lower than previous price spikes and have had little effect on average prices

8.26 Although it remains uncertain whether the overall offer behaviour was efficient, final prices have settled at similar levels in the past and the average prices for the day in both islands were within what would be considered to be a normal range and normal volatility.

8.27 Figure 8 shows daily average prices at Otahuhu and Benmore since the establishment of the New Zealand electricity market. The 2 June prices were observable as the spikes in daily price at the very right hand side of the figure. Analysis of the data indicated there have been 14 events where prices have exceeded $2,000 per MWh, including this event.

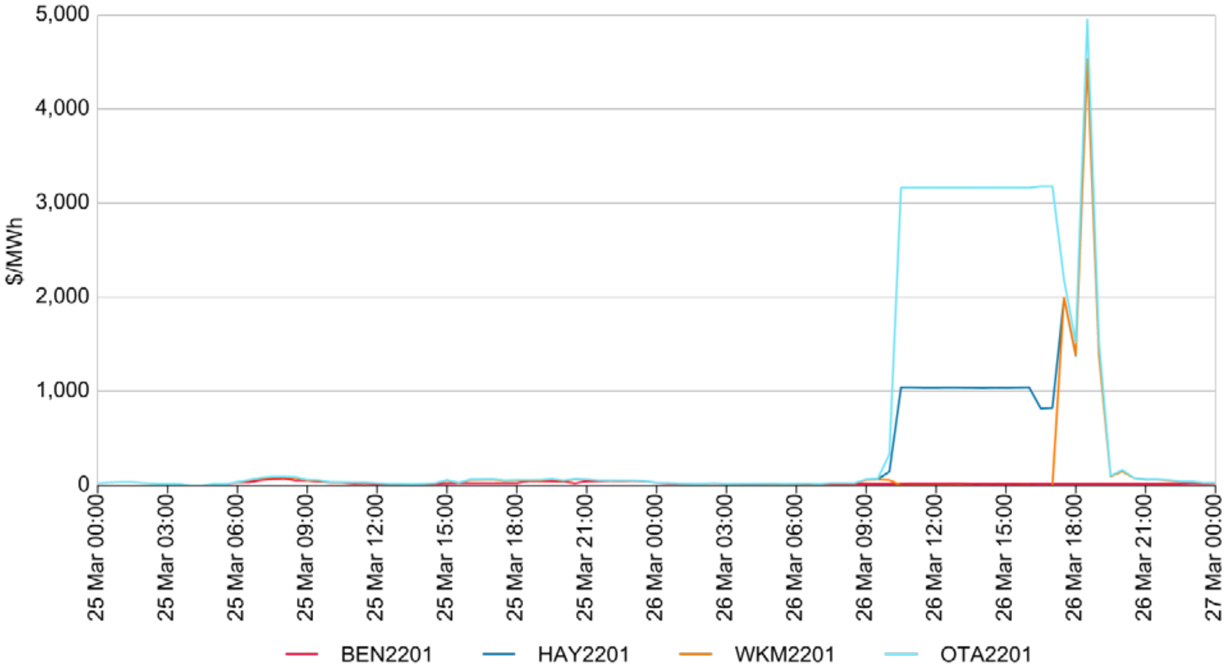
Figure 8: Daily average prices at Otahuhu and Benmore



Source: Electricity Authority

8.28 As a reference, the prices were lower than the (corrected) price levels resulting from the 26 March 2011 UTS, and were also of a shorter duration. The 26 March 2011 UTS extended through 14 trading periods (10:30 to 17:30), so had a much more significant overall market impact. Figure 9 shows the prices for selected nodes over the period of the 26 March 2011 UTS.

Figure 9: Various nodal prices on 26 March 2011 – corrected final prices



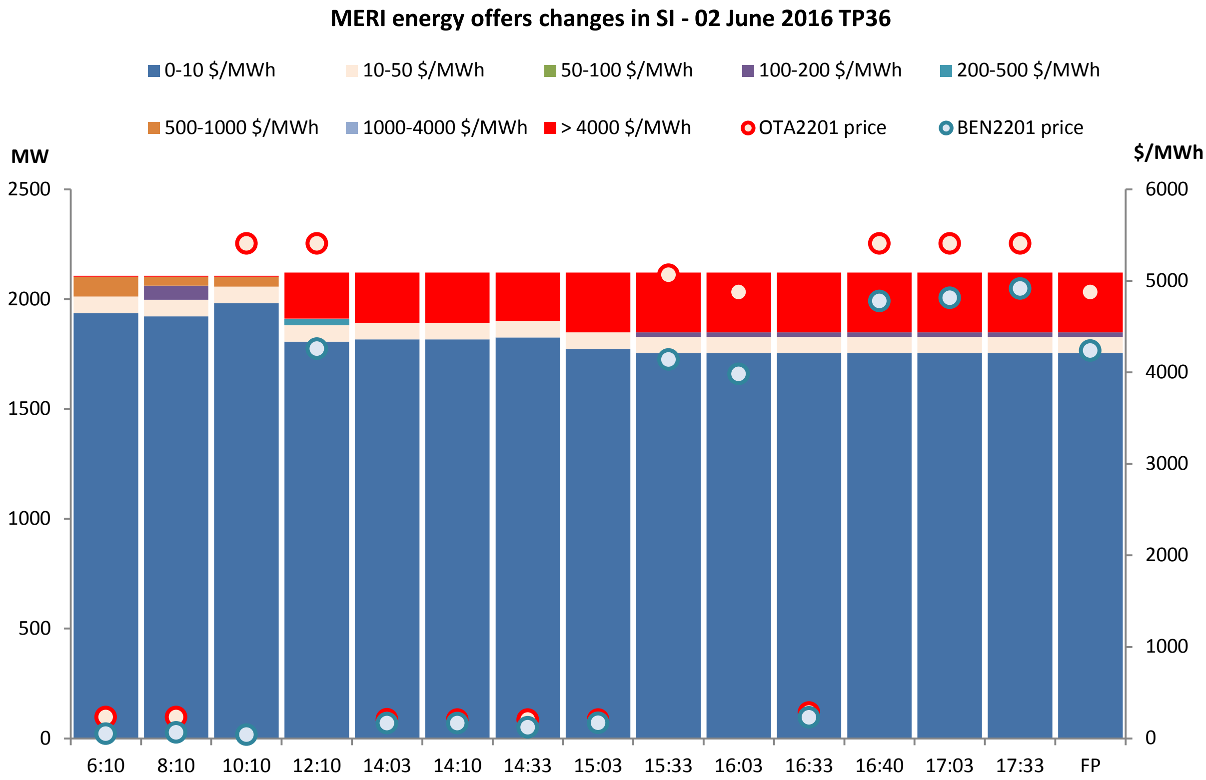
Source: Electricity Authority

9 Meridian's offer strategy was intended to address the risk of material inter-island price separation

Meridian's offer changes followed inter-island price separation being signalled in the NRS

9.1 Figure 10 - Figure 12 below show Meridian's offer changes and the pre-dispatch prices shown in the NRS at the time the offer changes were made. As noted at paragraph 6.5, Meridian advised that it uses the NRS to make decisions about offers in these sorts of situations. The left-hand axis shows Meridian's offer volume and the right-hand axis shows the offer price (by tranche). The x-axis shows the times that the NRS was published, and the circles show the prices for Otahuhu and Benmore shown in those schedules.

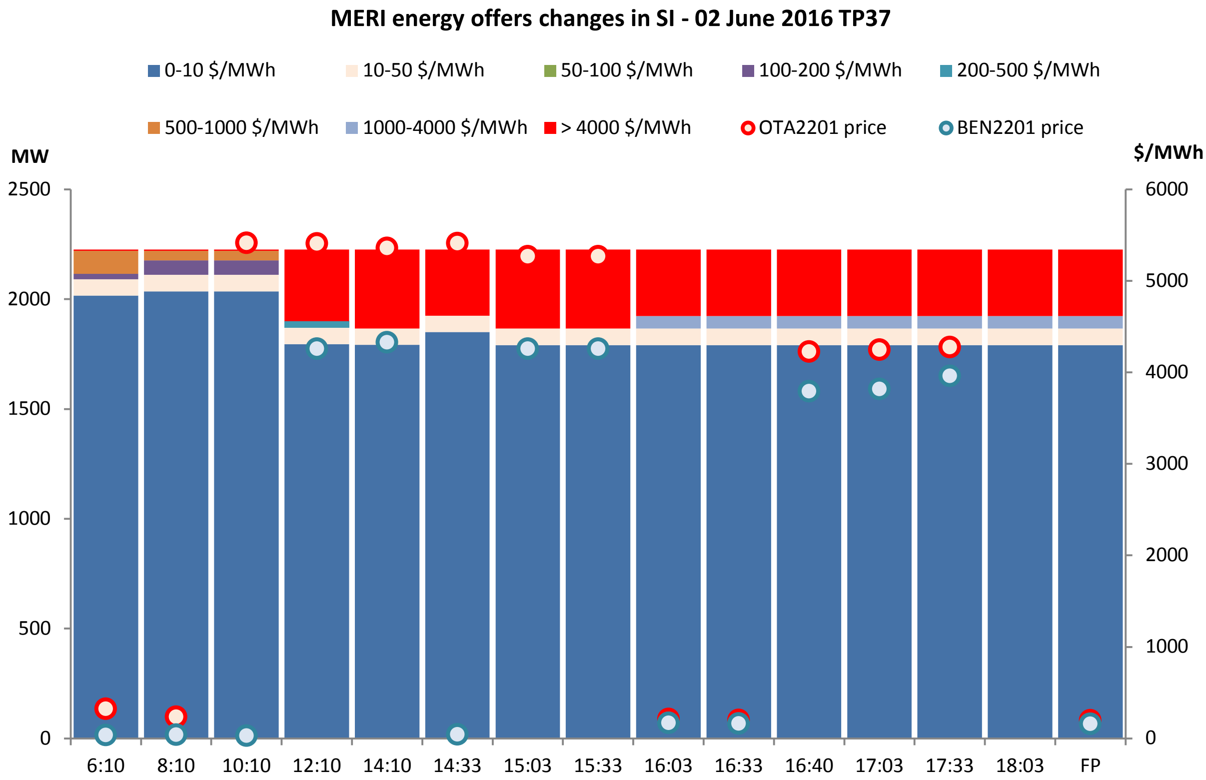
Figure 10: Meridian's offers in TP36 and the NRS at Benmore and Otahuhu



Source: Electricity Authority

9.2 Figure 10 shows Meridian's offers for TP36. The main offer changes happened between 10:00 and 12:00 as indicated by the introduction of the red band of offers over $4,000/MWh. This was in response to the large separation in prices seen in the NRS at 10:10. From that point on, Meridian made smaller changes to its offers until its last changes before gate closure at 15:33. It is observable that the prices between the islands became linked once Meridian's initial offer changes had been made, with significantly less separation than indicated in the NRS at 10:10.

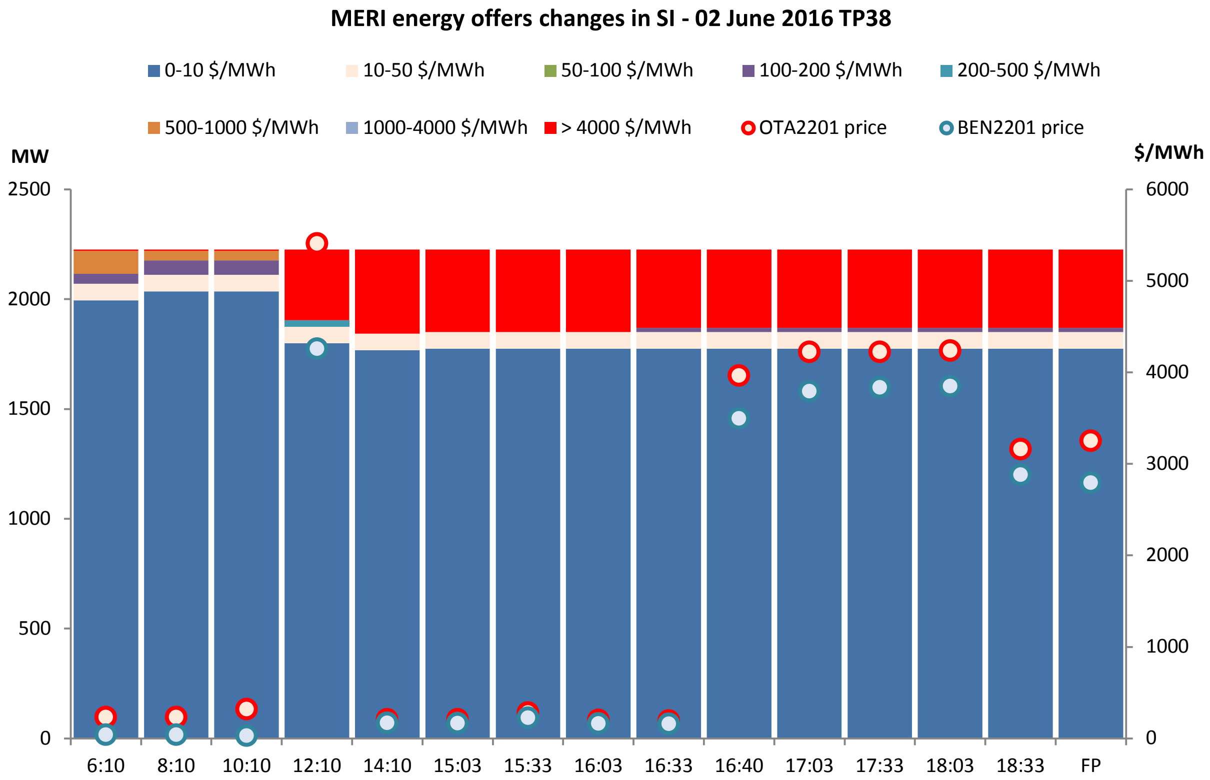
Figure 11: Meridian's offers in TP37 and the NRS at Benmore and Otahuhu



Source: Electricity Authority

9.3 Figure 11 shows Meridian's offers for TP37, and this shows a similar pattern to that for TP36. Some additional price separation can be seen at 14:33, which was after the main offer changes at 11:33. Meridian made smaller offer changes after the main change until the final changes were made at 16:03. Prices at Otahuhu and Benmore were linked after this point, but vary between $200 and $4,000 per MWh leading up to real time.

Figure 12: Meridian's offers in TP38 and the NRS at Benmore and Otahuhu



Source: Electricity Authority

9.4 Figure 12 shows Meridian's offers for TP38. Meridian's main offer changes occurred at 11:33 and prices did not rise until after Meridian's last offer changes at 16:33. As noted at paragraph 6.9, Genesis made an offer change for Waikaremoana at 15:15, and this will also have influenced prices in the subsequent schedules.

Meridian has explained its offer strategy in response to questions from the Authority

9.5 In order to understand the rationale for Meridian's offer behaviour, the Authority put a number of questions to Meridian. Meridian's responses to the questions are provided in Appendix B.

9.6 Some of the key elements of Meridian's response are summarised below:

(a) High demand, HVDC capacity constraints and a forecast of zero North Island wind generation output meant that Meridian faced material revenue exposure when attempting to meet its retail market position.[19] Meridian considered there was a high likelihood that Contact's offer of $5,000/MWh for its Whirinaki generator would be the marginal generator for the relevant trading periods, and modified its offers accordingly.

19 Meridian receives the wholesale price that applies at the nodes where it sells its generation into the wholesale market, and purchases electricity at the wholesale price that applies at the nodes where it retails to consumers. When the price at which it purchases electricity becomes higher than the price that it sells electricity they will face revenue exposure (ie, its generation revenue is insufficient to meet its purchase costs), subject to the impact of any financial instruments it might apply to manage the risk of this occurring.

(b) For various reasons, Meridian did not consider that FTRs would have enabled it to manage this risk. Meridian considers FTRs to be a baseload product that is not suited to peak exposure issues, and that FTRs come with their own trading risks that can make them a relatively expensive risk management tool in some circumstances.[20]

(c) Other products such as contracts for difference and ASX NZ Electricity futures are also used where it is considered cost effective and appropriate to do so. These products have their own contracting costs, and may not cover all relevant outcomes.

(d) The approach taken to the 2 June event was consistent with Meridian’s standard approach for managing the risk of price separation between the islands during times of high HVDC transfer. While Meridian was not able to confirm how frequently this trading practice occurred, it was clear it happens on a reasonably regular basis (Meridian refers to “many occasions”).

(e) Meridian’s working assumption is that it is operating in a competitive environment and that competitors may and will make decisions that affect final prices and final cleared quantities of generation.

(f) Meridian considered that the market outcome for the relevant trading periods on 2 June is reflective of that competitive environment. The offers of other parties set the prices for these trading periods, and forecast prices for each of TP36-38 changed after gate closure as a result of events outside of its control. Meridian suggested this was a result of competitive interaction between offers from Whirinaki, Waikaremoana, and demand.

(g) Meridian had not observed any changes in confidence in, or the integrity of, the market since the event, and had noted it continued to be approached for over-the-counter products.

(h) Meridian considered its offers were consistent with the principles of the safe harbour in clause 13.5B of the Code, and constituted a high standard of trading conduct in accordance with clause 13.5A of the Code. In doing so, Meridian said the safe harbour provisions were not well framed to deal with Meridian’s circumstances, where it is pivotal in the South Island for a large proportion of the time but needed to take market actions in context of its overall NZ market position.

(i) While it is not mentioned in Meridian’s written response, Meridian orally identified a concern with the way that the system operator considers wind output when calculating the HVDC transfer risk. Meridian considered this leads to an over-procurement of reserves, with consequential impacts on prices.

10 Basis risk management is a recognised trading strategy

10.1 Basis risk is the risk associated with imperfect hedging. The term basis risk is understood to refer to the risk that the price of a futures contract (or hedging instrument) won’t converge to the price of the underlying physical asset. For a vertically integrated generator-retailer that typically runs a close-to-neutral hedge position (as is the case with

20 Meridian also noted that FTR offer volumes were constrained for June 2016 as a result of the HVDC filter outage, and that FTR market revenue certainty was also reduced accordingly.

the four main New Zealand generator-retailers: Contact, Genesis, Meridian and Mighty River Power Limited), the primary hedging "instrument" is their physical generation portfolio. Hence, in the New Zealand context, basis risk concerns the difference between the price received for generation compared to the price paid for purchases; the locational price risk.

10.2 The ISO definition of risk is "the effect of uncertainty on objectives". It is this effect of uncertainty that may cause parties to carry out such actions as entering into hedge contracts, or constructing their offers in a certain way.

10.3 In this case, the analysis showed that, if Meridian had kept its offers at original levels (holding all else equal) there would have been no inter-island price separation (as discussed in paragraphs 8.17-8.18, above) and final prices would have settled at significantly lower levels. But, if it is assumed that Meridian was changing offers solely to manage basis risk, as it has asserted, the effect of the uncertainty of inter-island price separation led Meridian to construct offers that either caused, or at the least contributed to, prices rising in both the South and North Islands.

10.4 Another observation was that locational price risk is not about *physical* congestion on the grid, it's about *price risk* across the grid. While a physically congested grid *increases* the likelihood that price separation can occur, generator offers can be structured in such a way as to *decrease* the likelihood that price separation occurs even when the grid is congested.

10.5 Appendix E contains an example of how different trading tactics around an export constraint can affect market outcomes.

10.6 The example in Appendix E also includes a case study of how generator offers likely responded to a system constraint resulting from a Tiwai transformer outage in 2008. This case study highlights that basis-risk management through managing spot offers has been an active strategy for generator-retailers for some time. The tactic of offering plant in such a way to keep prices connected with the rest of the grid that is presented in the case study is conceptually no different to the Meridian behaviour over the UTS claim period; albeit with quite different price impacts.

10.7 Information collected as part of the Authority's market performance enquiry into the relatively high energy prices that occurred over 16 trading periods in the period between 15 and 25 June 2015 also suggested that offer behaviour was being used to manage basis risk in a similar manner to the behaviour observed on 2 June 2016.[21] No UTS claims were submitted in relation to those trading periods, though the high prices were also significantly lower than those on 2 June 2016, sitting in the range of $200-400 per MWh.

Offering plant in a manner that is intended to manage basis risk was accepted as being "logical" in the Authority's decision on the 26 March 2011 UTS

10.8 The use of changes to generation offers to manage basis price risk was also clearly visible in the Authority's decision on the 26 March 2011 UTS. The following extract from that decision discussed the action taken by Mighty River Power to address a "short"

21 See http://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/2015/high-energy-prices-15th25th-june/. A market performance enquiry represents that first stage of the Authority's structured market monitoring process. The Authority has not concluded this enquiry so has yet to publish any results.

market position it was experiencing during that event as the result of a binding transmission constraint:[22]

Analysis – did other parties participate in the squeeze?

146. A squeeze in the wholesale market for electricity need not be a certain matter. There may be uncertainty as to whether a generator is net pivotal, the level of demand on the day, and the extent to which participants are aware of events in the market (producing uncertainty about any consequential behaviour by those participants).

147. By increasing its Waikato generation offer prices, Mighty River Power's offer behaviour was consistent with an attempt to bring about a market squeeze affecting the rest of the North Island. However, in a letter to the Authority on 29 April 2011 Mighty River Power stated:

- "Mighty River Power had circa [ ]MW of gross short position north of the transmission constraint, and the binding constraint was preventing Mighty River Power being able to compete in the market north of the constraint. For clarity, these offer modifications were a reactive response to the price separation and would not have been undertaken had the transmission constraint not bound in combination with the offering strategy of Genesis Energy."
- "For clarity we were not seeking to leverage the high prices generated north of the constraint to other parts of New Zealand where, on the whole, we are net short. The core purpose was to lift prices in the region of a large proportion of our generation to reduce the price separation across the constraint to the north, and potentially also produce a dynamic response in the market."

148. The UTS Committee notes that Mighty River Power's explanation is a logical reaction to the high prices brought about by Genesis Energy's high offer prices for its Huntly units. As Genesis Energy reduced its offer prices at Tokaanu, Rangipo and Tuai to manage its overall position, Mighty River Power needed to increase its offer prices in the Waikato to manage its overall position.

10.9 The situation discussed in the above extract is analogous to that of 2 June. During the 2 June event, North Island offers created or threatened to create high prices north of the binding constraint (HVDC north transfer capacity). Meridian increased its offer price in response. As noted above, the Authority's decision paper on the 26 March 2011 UTS considered this tactic to be a "logical reaction" and did not constitute a market squeeze.

The other tools available to Meridian to manage basis risk may not have been sufficient for its purposes

10.10 That locational basis risk management through offer behaviour has been a longstanding activity is also evident through the decision to establish the FTR market. FTRs are intended as a "transmission hedge" to help manage the price differences that occur across different locations on the power system, including those resulting from physical constraints.

22 http://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/uts-26-march-2011/final-undesirable-trading-situation-decision-and-proposed-actions/.

10.11 The Authority's activities to develop the electricity futures market have also recognised that futures products can be useful for managing locational basis risk (amongst a number of other benefits). In developing both the FTR and futures markets the Authority has also recognised that these markets provide additional tools for managing basis risk. However, the use of these markets has not been mandated (ie, participants are not obliged to use them). This is because it is important that participants are able to make their own assessments of risk and determine the approach to risk management that best suits their requirements.

10.12 Meridian's response to the Authority's questions in relation to its trading behaviour on 2 June (see Appendix B) set out its view that the FTR market, and the other financial instruments available to Meridian for managing risks, were not suitable or sufficient for managing the specific risk being faced in this event. This may not necessarily be a view shared by other participants, who may consider that these instruments are sufficient. However, each participant's perspective on this issue is likely to be influenced by factors such as their own risk appetite and the nature of their generation and/or retail portfolio and position.

10.13 That said, it is appropriate to acknowledge that limitations in the markets for financial instruments may mean that these types of instruments may not always be able to fully cover a risk position. Examples of such limitations include the restriction in FTR volumes that are necessary in order to maintain revenue adequacy, and that the nature of the FTR market means that participants with a natural (physical) position in the market may not necessarily be able to purchase all of the FTRs they require to cover that position.

10.14 While the presence of the FTR market, and the increased liquidity seen in the ASX futures market, will have increased participants' ability to manage basis risk, further evolution of these markets may still be required. For example, the availability of cap products on the ASX futures market, which are planned to commence trading later in 2016, may have created another means for Meridian to manage at least some of the basis risk that it faced in this situation.

Evidence of prior behaviour does not necessarily make that behaviour appropriate, but can make it difficult to determine if the event is a UTS

10.15 The fact that a particular pattern of offer behaviour has occurred on a number of occasions in the past does not necessarily mean it is consistent with the Authority's statutory objective or meets the Code requirement for a high standard of trading conduct. However, it does mean that it is a known, and not unexpected, behaviour. It becomes harder to assert that, in the absence of other factors, an instance of the behaviour threatens, or may threaten confidence in, or the integrity of, the wholesale market when this has not been the case for previous occurrences.

10.16 Further, when it introduced the high standard of trading conduct provisions into the Code, the Authority noted that "*the Code currently sets a relatively high bar for the Authority to invoke the UTS provisions and this will not change under the proposed amendment*".[23]

10.17 The introduction of the trading conduct provisions did not change the test for determining whether a UTS exists.

[23] "Improving the efficiency of prices in pivotal supplier situations – Decision paper', 4 June 2014, at paragraph 105. The paper is available at http://www.ea.govt.nz/development/work-programme/wholesale/efficiency-of-prices-in-pivotal-supplier-situations/development/decision-paper/.

11 The situation does not constitute a UTS

11.1 The Authority finds that a UTS did not exist for TP 35 to TP 40 on 2 June because there is no evidence that the existing levels of confidence in, or integrity of, the wholesale market were threatened or may have been threatened (as discussed in section 7).

11.2 The reasons for this view are:

(a) Having considered a number of indicators of market activity, the Authority has not identified any discernible change that would suggest that the events of 2 June have impacted confidence in, or the integrity of, the wholesale market. Electric Kiwi is also the only market participant to have contacted the Authority with concerns about the situation on 2 June.

(b) The Authority considers the situation on 2 June was within the normal operation of the wholesale market, so does not threaten, or may threaten the existing level of confidence in, or the integrity of, the wholesale market. The situation was within the normal operation of the wholesale market because:

(i) Meridian's offer behaviour was not an unusual response for a market participant facing the risk of financial loss as a result of the tight and uncertain market conditions that existed in the North Island over the relevant trading periods. There is evidence that a similar approach is also used by other industry participants to manage the risk of financial loss when faced with similar scenarios of basis (or locational) price risk. That this type of offer behaviour has occurred regularly in the past, without creating a UTS, suggested that the behaviour alone was not sufficient to warrant a UTS finding (as discussed in section 9).

(ii) The offering behaviour of other market participants, and an unscheduled generation outage, had equivalent impacts on the market outcomes to Meridian's offer behaviour (as discussed in section 8).

(iii) Meridian may have relied on its offering strategy to manage the risks it was facing as a result of limitations in the risk management products available in the market (as discussed in section 9).

12 The event raises issues that warrant further investigation through a market performance review

12.1 While the Authority has found that the 2 June event did not constitute a UTS, Electric Kiwi's UTS claim has raised a number of issues that the Authority considers require further investigation. For example, the event described in the claim represents the first real test of the Code provisions requiring a high standard of trading conduct, and there is merit in considering how well those Code requirements accommodate the specific scenario encountered in this event.

12.2 The Authority has therefore decided to review the event further by undertaking a market performance review.[24] This review is expected to include further consideration of whether:

[24] A market performance review represents the second stage of the Authority's structured approach to the monitoring of circumstances that have given rise to an out of the ordinary event. A review can proceed to an investigation depending on the extent of information gathering and analysis that is required. More

(a) the trading behaviour, while not uncommon, is consistent with the Authority's statutory objective

(b) relevant Code provisions are achieving the intended outcomes

(c) the risk management products available in the hedge market, including those in the FTR market, are sufficient in their range and scope.

12.3 The outcome of this review may identify potential improvements to the Code, trading arrangements, and to the scope and availability of risk management products that result in a better functioning wholesale electricity market.

13 The Authority will investigate any potential Code breaches

13.1 At the same time as it carries out a market performance review, the Authority may investigate whether there has been a breach of the Code. The two processes may run concurrently.

13.2 In this case, the Authority will consider whether a compliance investigation is warranted following the completion of the market performance review.

13.3 Any participant that considers that there has been a breach of the Code in relation to any aspect of the 2 June event can allege that breach directly to the Authority.

information on the Authority's monitoring process is available at http://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/our-three-stage-process/.

Appendix A Electric Kiwi's 'Claim of undesirable trading situation (UTS)', received on 16 June 2016

CLAIM OF UNDESIRABLE TRADING SITUATION (UTS)

CONTACT DETAILS

Reporting Organisation: Electric Kiwi

Contact Name: Phillip Anderson

Email: phill@electrickiwi.co.nz

Phone: 021460040

Mobile: 021460040

Fax: N/A

WHEN CLAIMED UTS OCCURRED

Date: 2 June 2016

Time: 17:00 to 20:00 hours (TPs 35 – 40)

In addition to completing and emailing this form, please also notify the Authority by telephone at **04 474 2260**.

BASIS OF CLAIM

Why is this event an "undesirable trading situation"?

Please specify why a UTS is claimed – refer to the definition of a UTS set out below:

Clause 1.1(1) of the Electricity Industry Participation Code 2010 (Code) - Meaning of undesirable trading situation

undesirable trading situation means any situation—

- that threatens, or may threaten, confidence in, or the integrity of, the **wholesale market**; and
- that, in the reasonable opinion of the **Authority**, cannot satisfactorily be resolved by any other mechanism available under this Code.

Describe why in your view the claimed UTS is a situation that threatens, or may threaten, confidence in, or the integrity of, the wholesale market.

Figures 1 and 2 below show that at 11.54 on the 2nd of June Meridian rebid their offer for TP 36 and at 13:52 Meridian rebid their offer for TP 38

Figure 1 Meridian's record of rebidding leading up to TP 36 2 June 2016

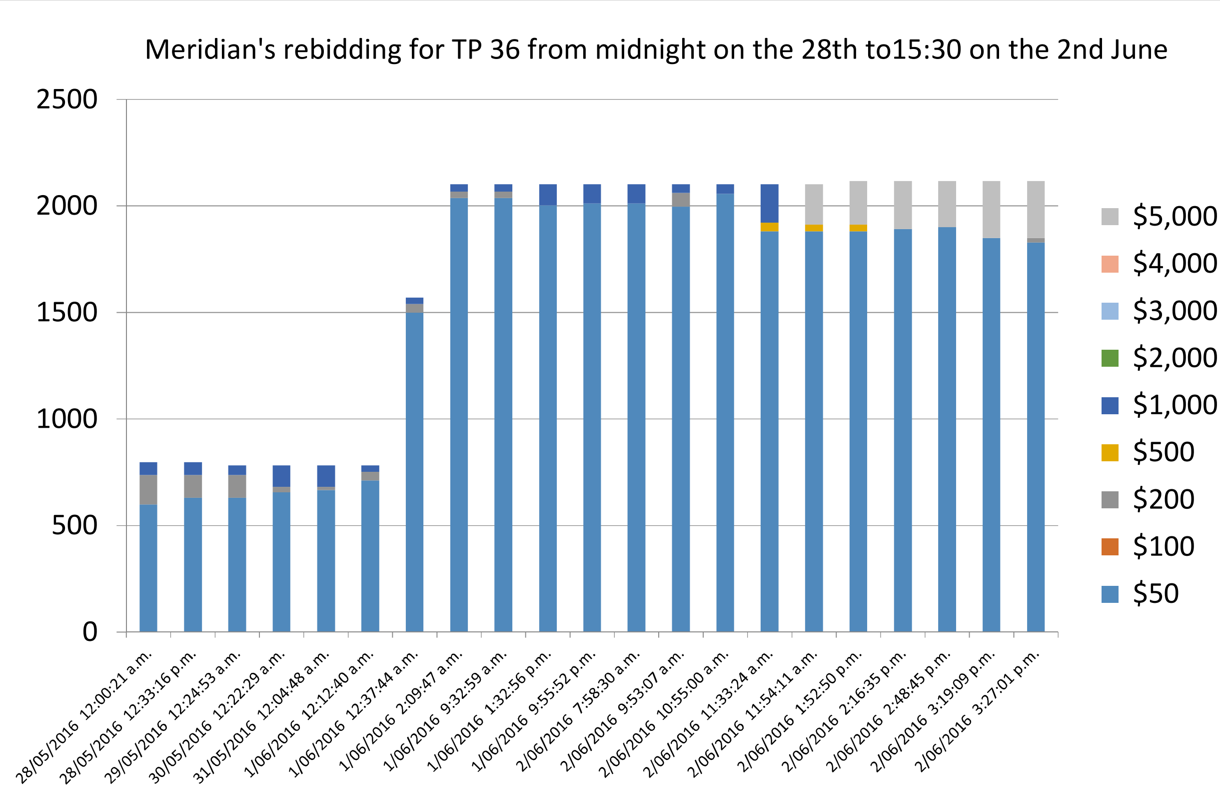


Figure 2 Meridian's record of rebidding leading up to TP 38 2 June 2016

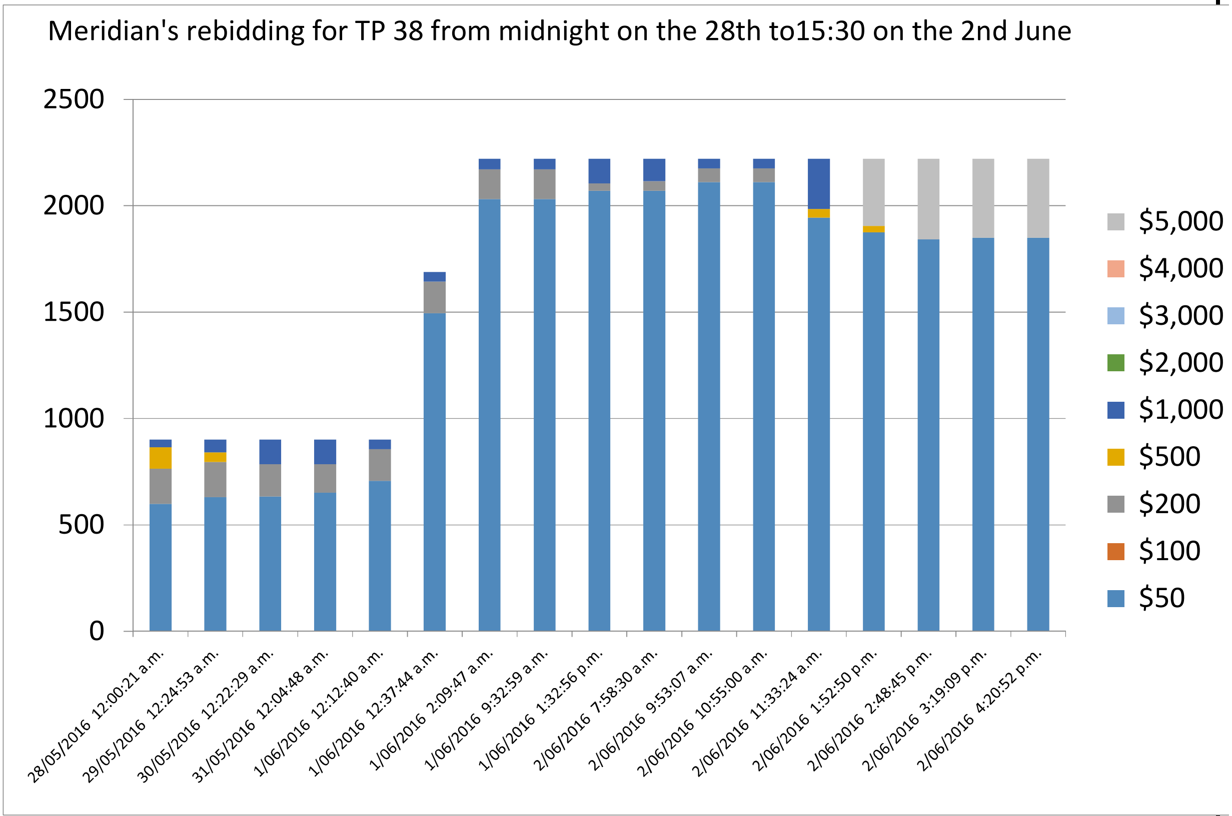


Figure 3 and 4 shows the difference between final offers and cleared prices on Wednesday 1 June and Thursday 2 June

Figure 3 Final offers and cleared energy for Wednesday 1 June 2016

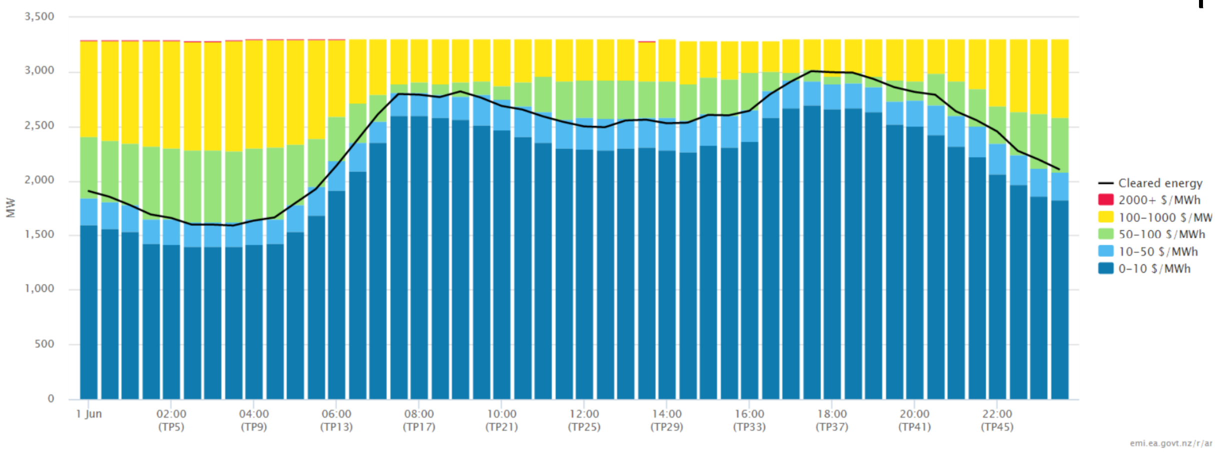


Figure 4 Final offers and cleared energy for Thursday 2 June 2016

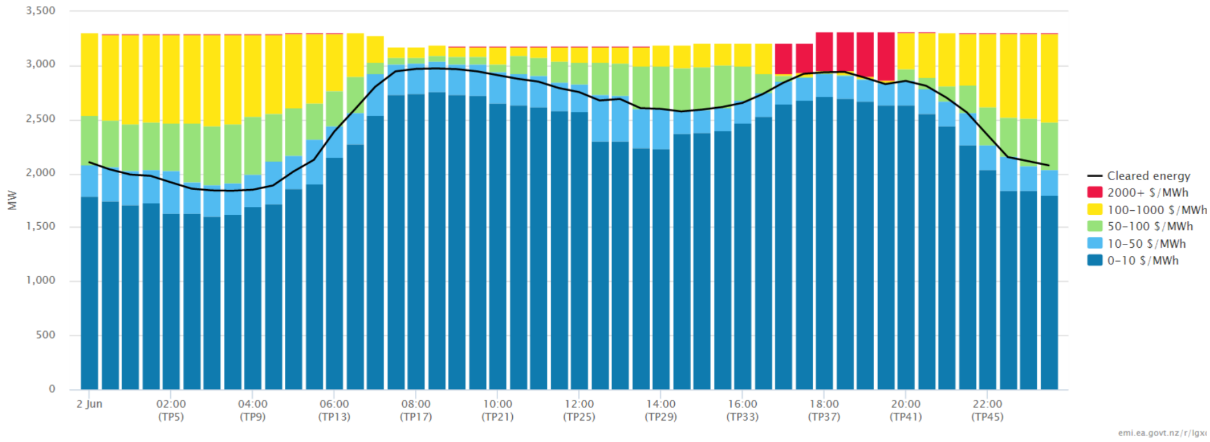


Figure 5 Cumulative South Island offer stack for Meridian 30 May – 2 June

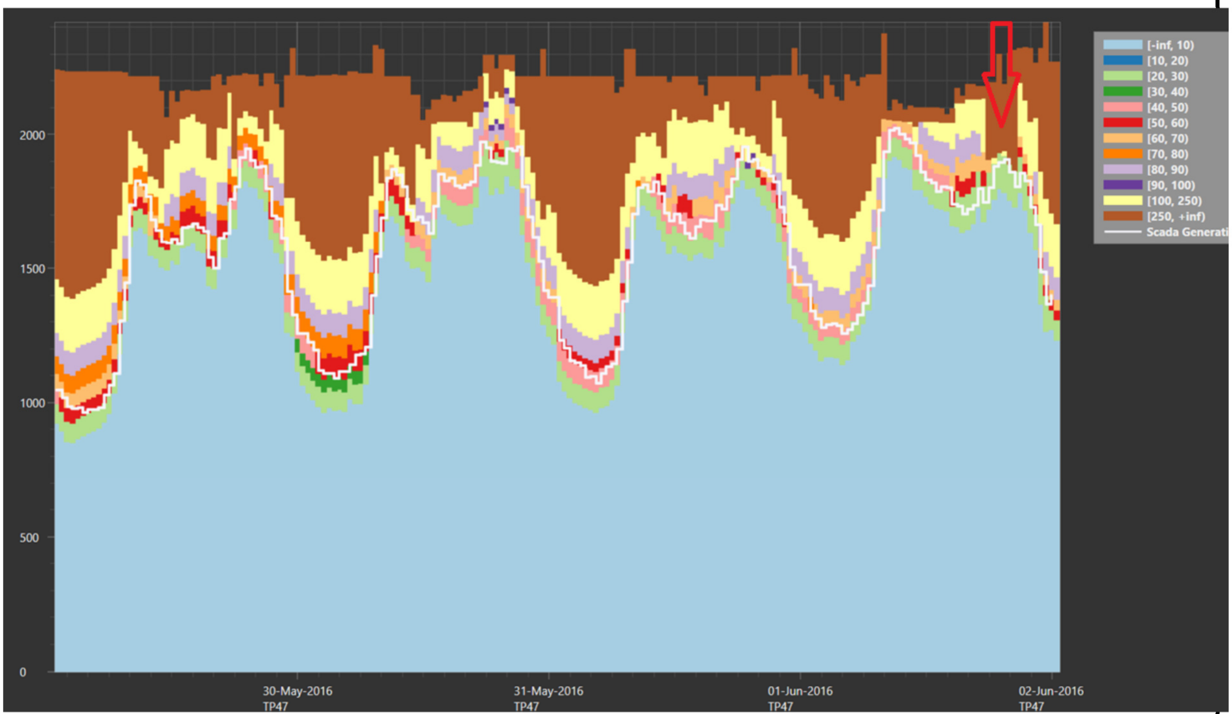


Figure 5 shows Meridian's final offer stacks for 30 May – 2 June From figures 1-5 we learn the following:

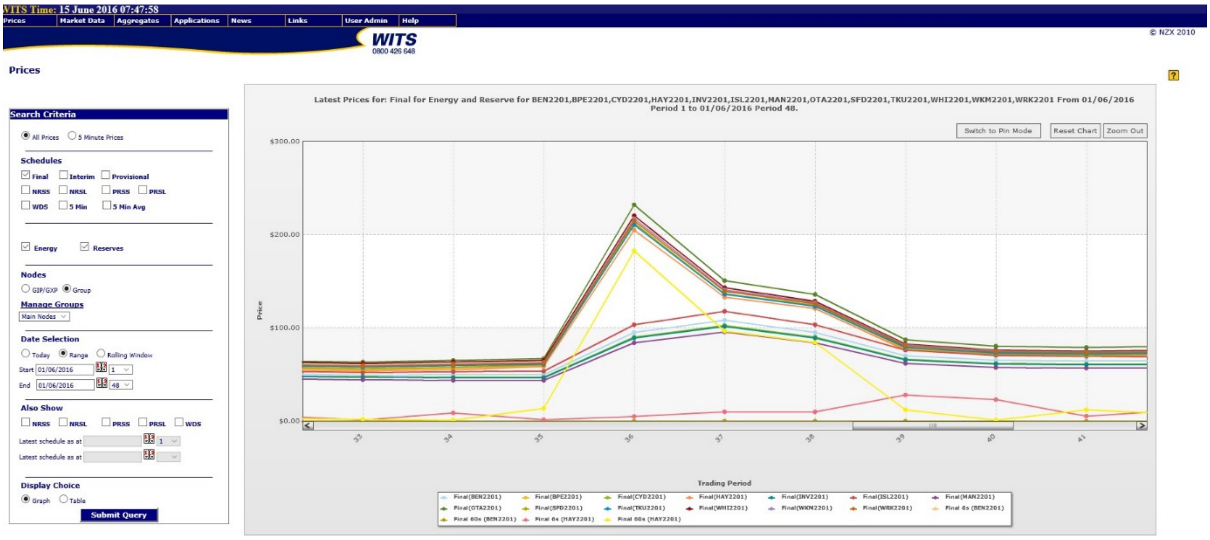
- Meridian changed their offer relating to TPs 35 – 40 through the middle of the day on June 2
- The altered prices for the offers could have been anywhere between what Meridian bid earlier and any level they chose because they were pivotal. By pivotal we mean that the total demand in the target TPs would not have been met if the generator had not submitted offers for all or any of its generating plant as per the definition in the Code.
- The fact that Meridian raised its offers to $5000 when it was net pivotal constitutes an undesirable trading situation as their action threatens, or may

threaten, confidence in, or the integrity of, the wholesale market; and cannot satisfactorily be resolved by any other mechanism available under the Code. That is to say there was no economic underpinning for the increase in offer price other than the fact that they could do so because they were pivotal.

Below we trace the timeline of key events leading up to Meridian's offer changes.

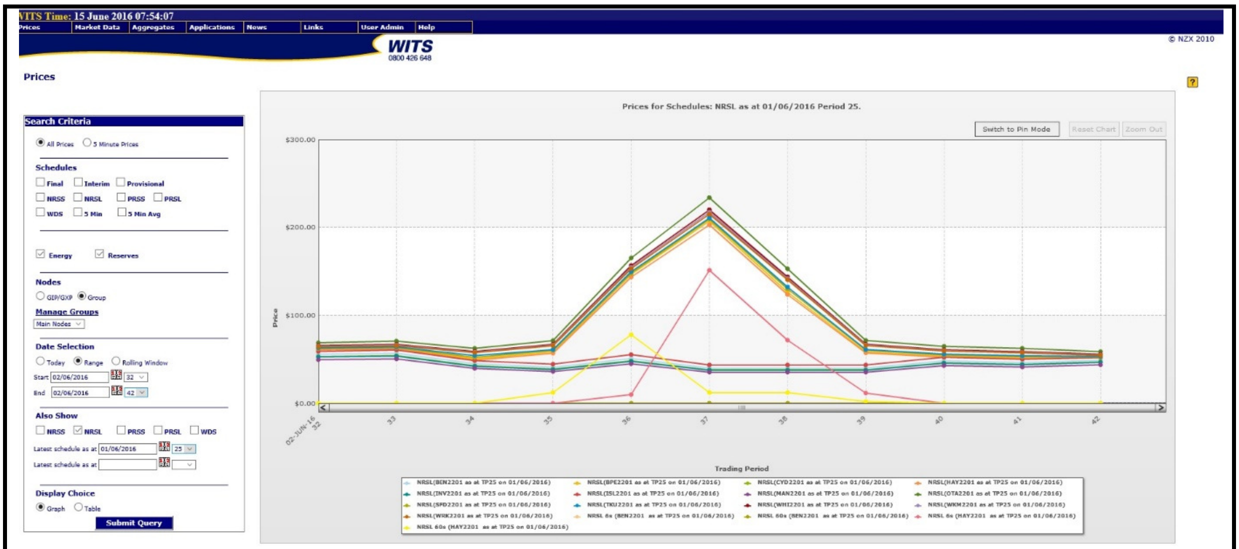
Wednesday, 1 June, final prices

Prices separated in the evening peak on Wednesday, 1 June but at a relatively moderate level.



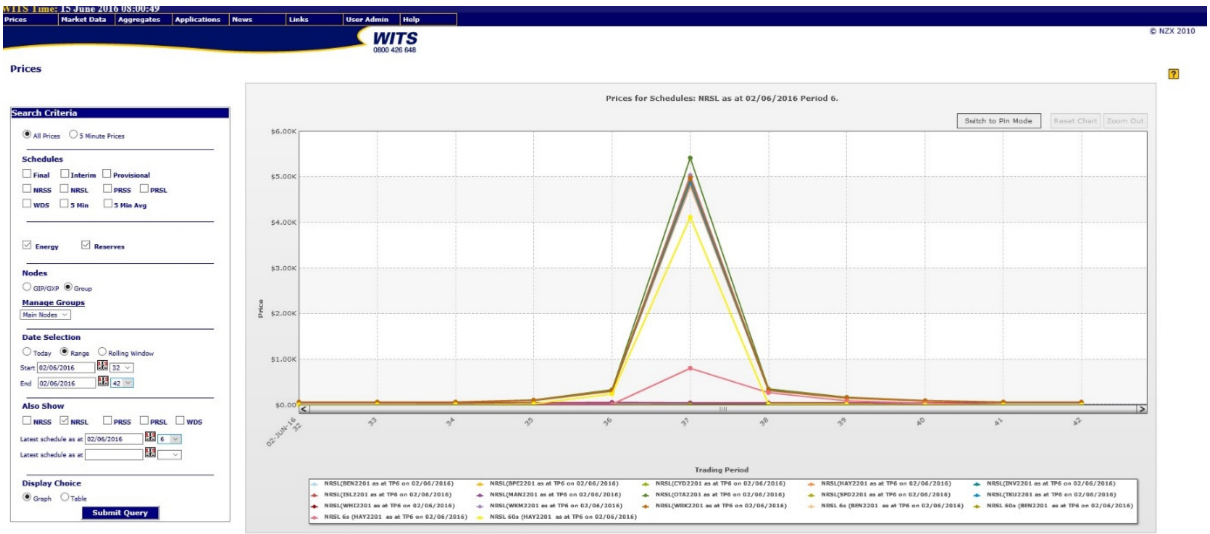
Wednesday, 1 June, NRSL prices, runtime period 25 (for 2 June)

Thursday was very similar conditions to Wednesday and price separation for the evening of 2 June was evident in every NRSL, starting on 1 June.



Thursday, 2 June, NRSL prices, runtime period 6

In period 6 prices in the North Island jumped from $200 - $300/MWh in the evening peak to around $5,000/MWh. The peak price stayed over $4,000/MWh in the North Island for the rest of the schedule and into final prices.

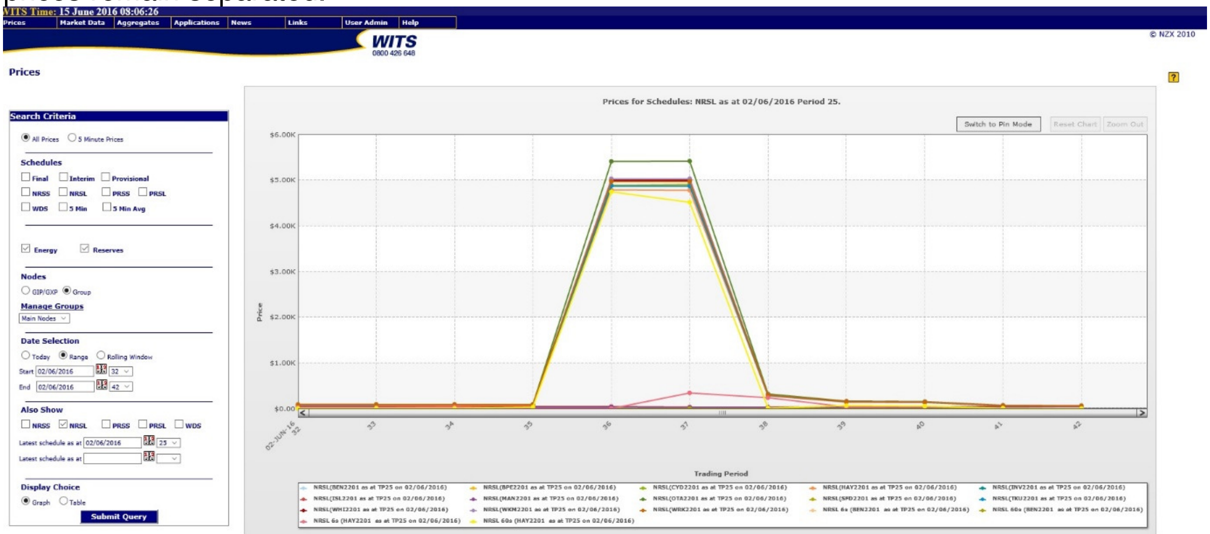


Our understanding of the situation is that the North Island was close to a shortage of n-1 capacity. As a result the North island needed significant South Island generation to be sent across the HVDC. This in turn was constrained by a shortage of, primarily, 60s reserve in the North Island where any number of reserve providers were probably pivotal in that the demand for reserve could not have been met without them. Fundamentally, there was little generation capacity available to relieve the HVDC flows, which is likely to have caused the price leverage that resulted in the very high North Island prices in period 36. This meant that Meridian had to supply the South Island and meet the North island capacity to the extent that it could be dispatched across the HVDC. Meridian was pivotal for energy in both the

North and South Islands and many providers were probably pivotal for NI 60 second reserve.

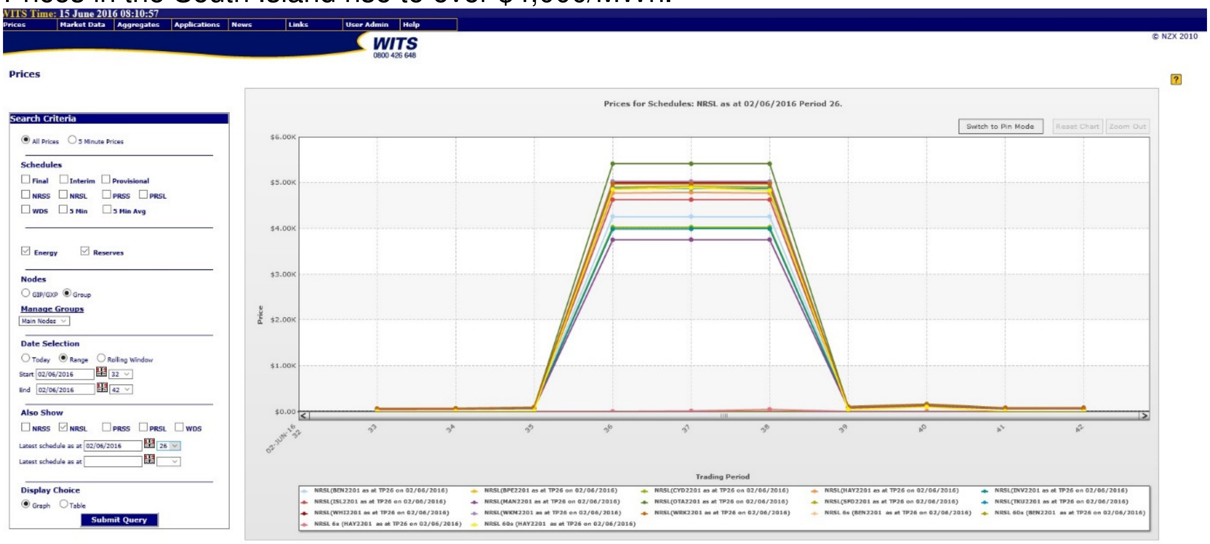
Thursday, 2 June, NRSL prices, runtime period 25

Meridian move significant volumes from low priced tranches to a [>$4,000] tranche but prices remain separated.



Thursday, 2 June, NRSL prices, runtime period 26

Prices in the South Island rise to over $4,000/MWh.

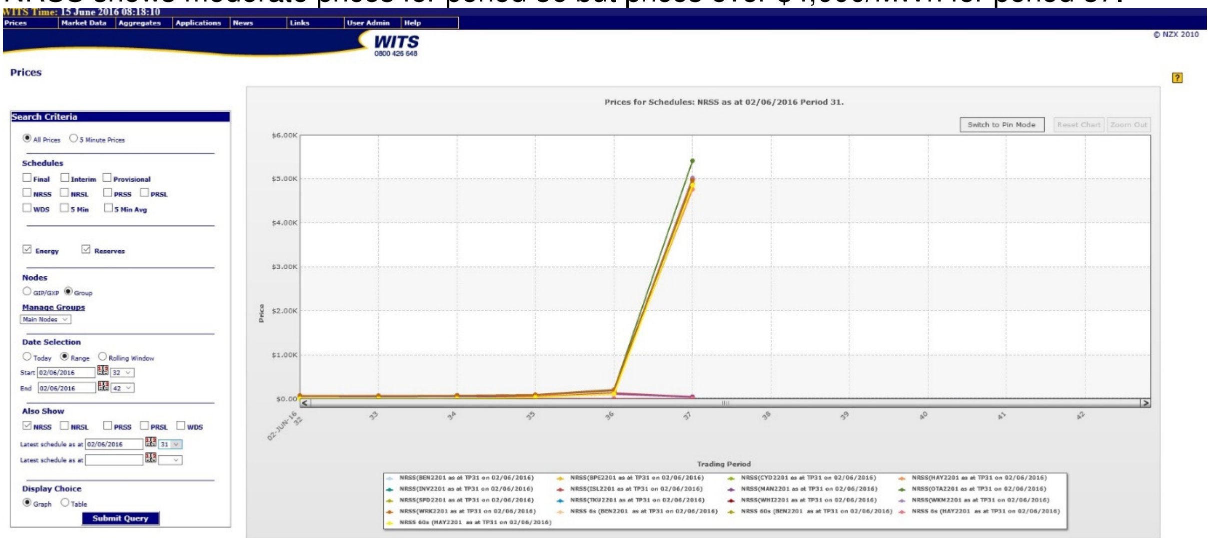


We understand that by now North Island dispatch was setting prices in the South Island. This implies that generation in the South Island could be displaced by North Island generation. This is true at the margin. There was sufficient generation in the North Island for Meridian to offer its capacity in a way that marginally relieved the HVDC reserve constraint while the North Island maintained a higher price. North Island dispatch still needed to maximise HVDC transfer.

The test for pivotal is whether, if Meridian had not submitted offers for all or any of its generating plant then demand could not have been met in the North or South Islands. That condition is met here.

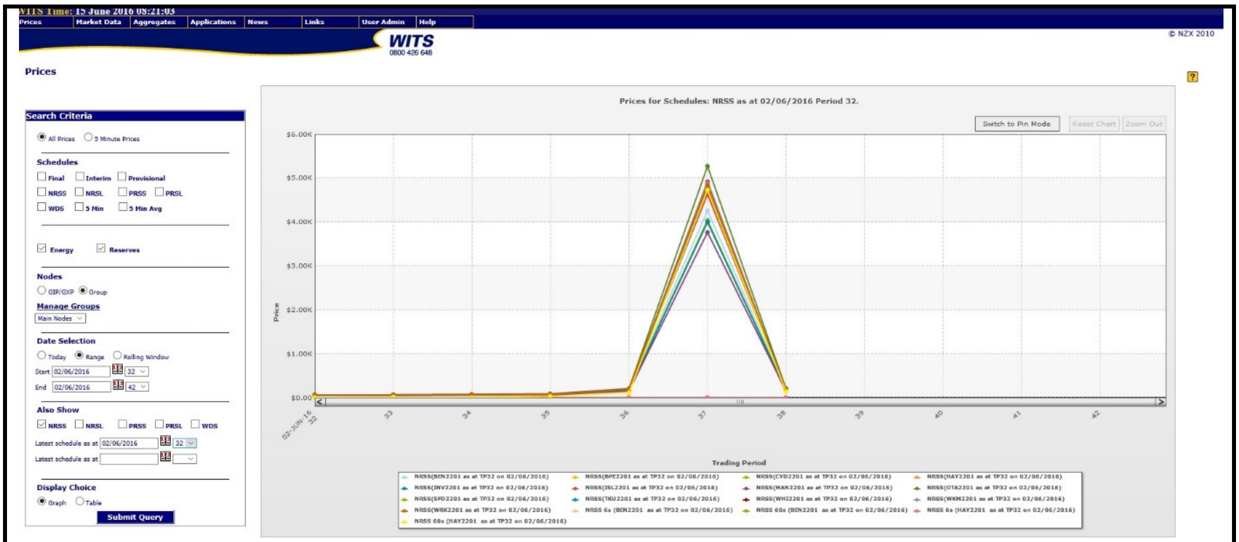
Thursday, 2 June, NRSS prices, runtime period 31

Prices remain over $4,000/MWh in the NRSL but the first NRSS that applies for period 36 shows no price separation even after Meridian had increase their offer prices. The next NRSS shows moderate prices for period 36 but prices over $4,000/MWh for period 37.



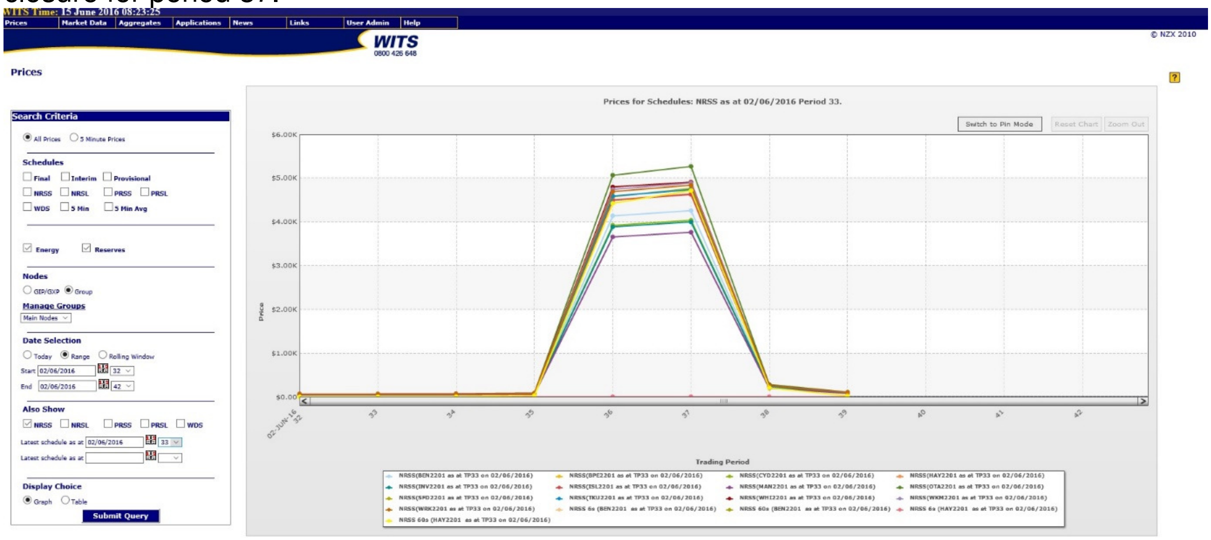
Thursday, 2 June, NRSS prices, runtime period 32

The next period shows high prices for period 37 but moderate prices for periods 36 and 38. Gate closure for period 36.



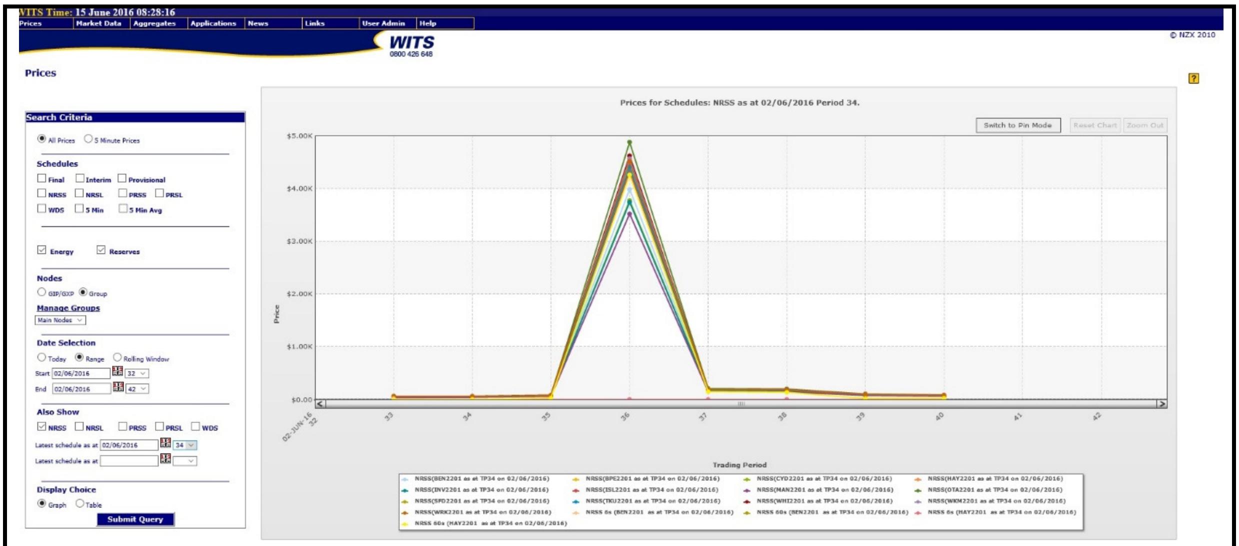
Thursday, 2 June, NRSS prices, runtime period 33

The next period prices lift in period 36 as well as 37. Period 38 remains moderate. Gate closure for period 37.



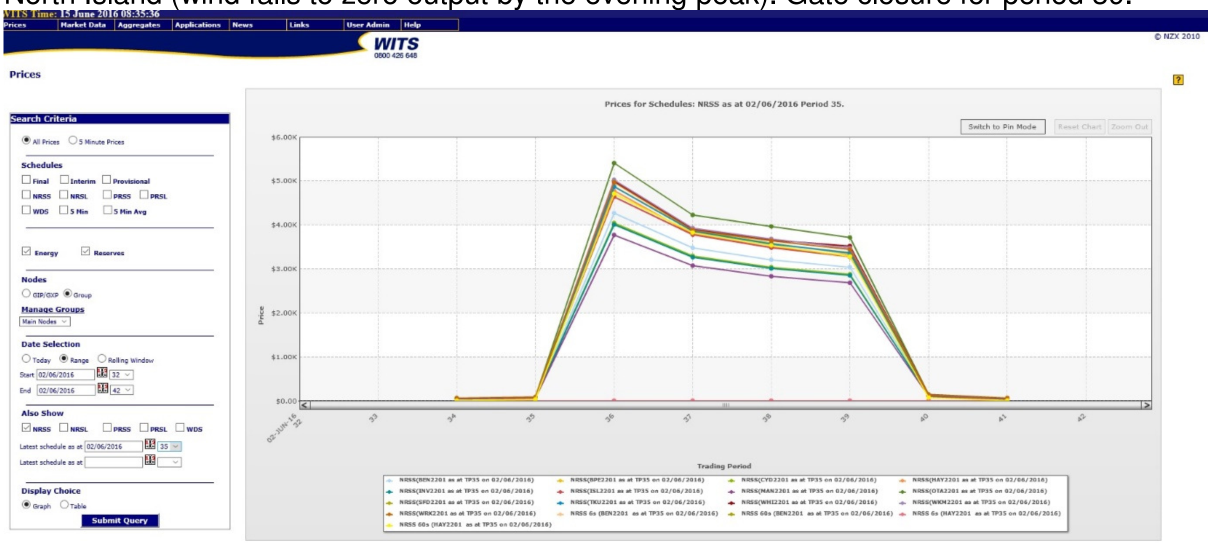
Thursday, 2 June, NRSS prices, runtime period 34

Prices ease for period 37 but period 36 remains high. Gate closure for period 38.

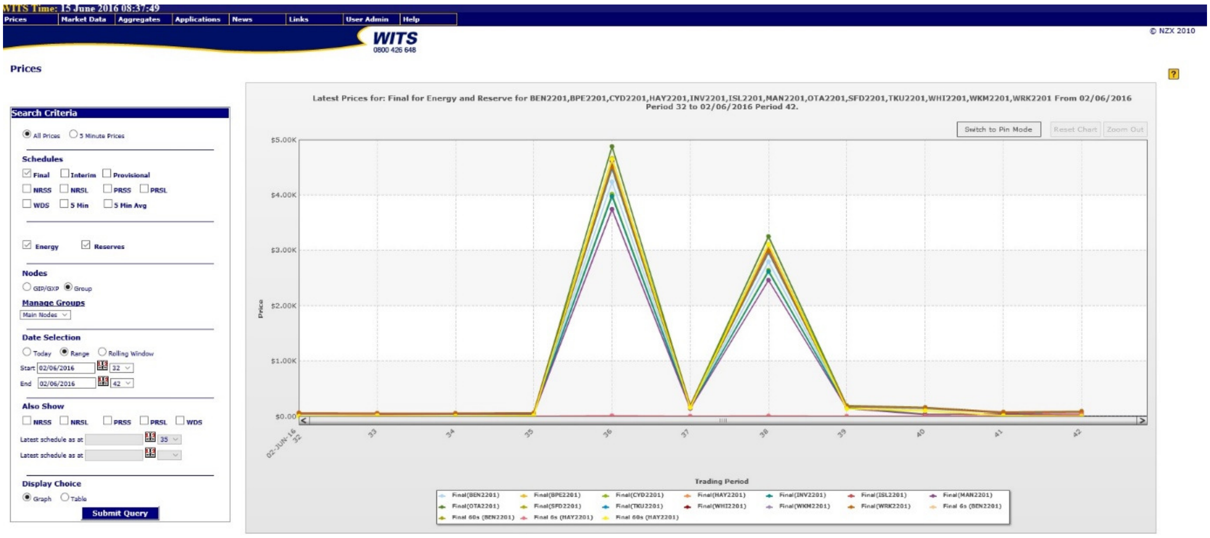


Thursday, 2 June, NRSS prices, runtime period 35

Prices separate for periods 36 to 39, possibly due to steadily decreasing wind forecast in the North Island (wind falls to zero output by the evening peak). Gate closure for period 39.



Thursday, 2 June, Final Prices



Electric Kiwi submits that the final prices in TPs 36 and 38 were the result of Meridian's actions when it was pivotal and that their actions constitute an undesirable trading situation.

We may learn a little from comments quoted on website Stuff as coming from Mike Roan, the Manager of Wholesale Markets at Meridian regarding what was on Meridian's mind when they made their changes to their offer. We note that comments in the media cannot be relied on entirely but what he is quoted as saying is telling:

Mike Roan, manager of wholesale markets at Meridian Energy, said it was not correct that Meridian removed low-priced offers from the market.

"Supply from those hydro facilities on July 2 was very similar to that on July 3, and other days of the week, so it is not correct that we altered supply on that night.

"Changes to our offers were made earlier in the day in response to forecast low wind output in the North Island and high winter demand. The actual pricing calculations are quite complex and during times where supply is stretched to meet demand, prices can and do often lift."

Source; http://www.stuff.co.nz/business/81056892/some-households-may-have-paid-20-more-in-one-night-for-power-after-prices-spiked

To summarise our view from the analysis of offer prices, the time line of prices shown to the market and Mike Roan's comments:

- North Island prices were initially high for the evening peak of 2 June but no higher than the day before

- North Island prices for the evening peak increased significantly from period 6 on June 2
- South Island prices were initially relatively low in the evening of June 2 compared with prices in the North Island
- Meridian may have been exposed to selling in the South Island and buying in the North as indicated by the fact that Mike Roan's comments on website Stuff highlighted conditions in the North Island to explain their thinking in the South Island
- Meridian was pivotal in the South Island
- Through the day on June 2 Meridian acted to remove the constraint on prices between the South Island and the North Island by raising South Island prices
- Regardless of their commercial rationale they were net pivotal, they raised their South Island offer in a net pivotal situation and created an undesirable trading situation.

On this basis Electric Kiwi concludes that this situation was one that threatens, or may threaten, confidence in, or the integrity of, the wholesale market. That is that Meridian manipulated South Island prices during the North island peak shortage of 2 June knowing that they were net pivotal and knowing that prices would be higher than would have been the case had they not been net pivotal and not changed their offers once they identified that situation.

AND describe why in your view the claimed UTS could not be satisfactorily resolved by any other mechanism available under the Code.

Electric Kiwi believes Meridian may be in breach of Clause 13.5A and is not covered by Clause 13.5B. We do not believe that Meridian has breached any other rule. Under the definition of an undesirable trading situation.

"(b) that, in the reasonable opinion of the Authority, cannot satisfactorily be resolved by any other mechanism available under this Code (but for the purposes of this paragraph a proceeding for a breach of clause 13.5A is not to be regarded as another mechanism for satisfactory resolution of a situation)"

Therefore, we conclude that the claimed UTS cannot be satisfactorily resolved by any other mechanism available under the Code.

The provisions of clause 5.2 of the Code allow the Authority to remedy the UTS by directing that any trades be closed out or settled at a specified price.

Electric Kiwi has separately notified the Authority that Meridian may be in breach of Code clauses 13.5A (2) (a) and 13.5B (c) (i) (ii) (iii) with respect to the same circumstances.

SOLUTION SOUGHT BY APPLICANT

Clause 5.2 of the Code

Describe how in your view the claimed UTS could be resolved by the Authority, bearing in mind that clause 5.2 of the Code enables the Authority to take one or more of the following actions, should it find that a UTS does exist (please refer to the full text of clause 5.2 of the Code on the following page for more information):

- directing that an activity be suspended, limited or stopped, either generally or for a specified period:
- directing that completion of trades be deferred for a specified period:
- directing that any trades be closed out or settled at a specified price:
- directing a participant to take any actions that will, in the Authority's opinion, correct or assist in overcoming the UTS.

Electric Kiwi requests that the Authority:

1. Finds there was a UTS and takes appropriate disciplinary action on Meridian in the hope that this acts as a deterrent and they are less likely to do it again.
2. Directs that any trades be closed out or settled at a specified price as per clause 5.2 (2) (b).

Please send the completed form to uts@ea.govt.nz

Clause 5.2 of the Code - Actions Authority may take to correct undesirable trading situation

(1) If the **Authority** finds that an **undesirable trading situation** is developing or has developed, it may take any action that—

(a) the **Authority** considers is necessary to correct the **undesirable trading situation**; and

(b) relates to an aspect of the **electricity** industry that the **Authority** could regulate in this Code under section 32 of the **Act**.

(2) The actions that the **Authority** may take under subclause (1) include any 1 or more of the following:

(a) directing that an activity be suspended, limited or stopped, either generally or for a specified period:

(b) directing that completion of trades be deferred for a specified period:

(c) directing that any trades be closed out or settled at a specified price:

(d) directing a **participant** to take any actions that will, in the **Authority's** opinion, correct or assist in overcoming the **undesirable trading situation**.

(2A) A direction given to a **participant** under subclause (2)(d)—

(a) may be inconsistent with this Code; but

(b) must not be inconsistent with the **Act**, or any other law.

(3) The **participant** must comply promptly with a direction given to it in writing.

(4) A **participant** is not liable to any other **participant** in relation to the taking of an action, or an omission, that is reasonably necessary for compliance with an **Authority** direction under this clause.

(5) A **participant** does not breach this Code if it acts in accordance with a direction given under subclause (2)(d).

Appendix B Meridian Energy’s response to the Authority’s questions in relation to Electric Kiwi’s UTS claim

B.1 Sections of the letter included in this appendix have been redacted in order to protect commercially sensitive information provided in the original document supplied to the Authority.

meridian

27 June 2016

Doug Watt
Manager Market Monitoring
Electricity Authority – Te Mana Hiko
Level 7, ASB Bank Tower
Wellington
By email: doug.watt@ea.govt.nz

Dear Doug

Questions regarding UTS claim

In response to your questions received by email 24 June 2016 Meridian provides the following answers and, where necessary, explanations. We ask that as an interim measure this letter is treated as confidential and commercially sensitive. It may be that upon careful review we are satisfied that the letter contains nothing that cannot be publically disclosed but in the time available to compile these answers we have not had a chance to do such a review.

1. *Meridian changed prices leading up to real time on 2 June, what was the reason for this?*

   On 2 June it became clear that cold conditions (increasing demand) and no wind (undermining Meridian's North Island ("**NI**") wind generation) would leave Meridian's NI retail position exposed to capacity constraints on the HVDC link. With NI prices forming at high levels in the early hours of 2 June, Meridian reacted early, and then did not change its offer price, allowing the market plenty of time to respond.

   Prior to Meridian changing its offers, it had already become clear that in TP36-TP38 there was a real risk that Contact's Whirinaki $5,000/MWh offer (it offered 104MW in this tranche) could set the price for NI generation in those evening periods. That outcome would leave Meridian with approximately of revenue exposure. Meridian therefore offered a quantity above the level of its national contracted load at a price below the Whirinaki offer, in order to reflect the competitive reality that its South Island ("**SI**") generation was competing against NI generation (such as Whirinaki) and to manage its NI retail position risk. As it turned out, that was a material risk, as Meridian's national position ended up being only approximately and MW long in TP36 and TP38 respectively.

   From Meridian's perspective this was an entirely rational cost-minimisation action taken in response to competitive offers placed by other generators.

   a. *If it was to manage basis (locational) risk why doesn't Meridian use financial instruments such as hedges or FTRs?*

      Meridian does use financial instruments to manage risks. It integrates contracts for differences (CfDs), call options, futures products (ASX contracts), and financial transmission rights (FTRs) into its market position to ensure it can manage exposures in the spot market.

However, financial instruments come at their own cost and do not cover all outcomes. Meridian's generation portfolio, when combined with these instruments provides flexibility to manage many market circumstances.

Specifically in relation to FTRs, they are a useful basis instrument but, as described below, integrating them into Meridian's market position to cover peak exposures like that evident on 2 June 2016 has a number of challenges.

1. There is a risk that FTRs do not provide the basis hedge they are designed for as payments to FTR holders are not guaranteed.

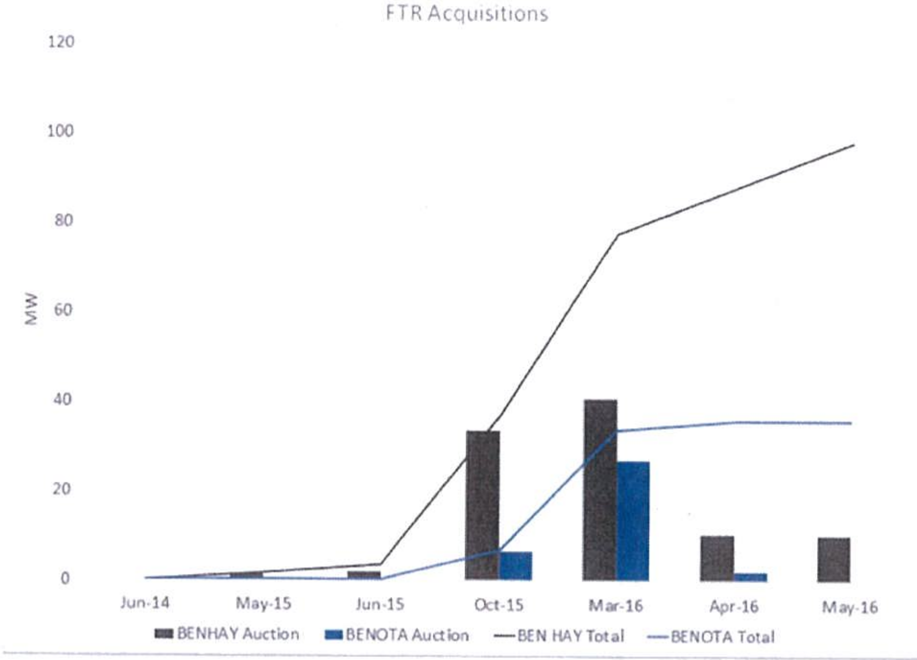
2. FTRs are baseload products whereas consumption changes during the day. As Meridian's market exposure is driven by that consumption profile, baseload products like FTRs tend to cover baseload rather than peak exposures.

3. FTRs are auctioned over a 24 month period and forecasting actual demand conditions and Meridian's market position up to 24 months in advance incorporates considerable error given the nature of specific risks like NZAS and systemic risks like the highly competitive retail environment.

4. FTR auctions are competitive and Meridian does not always purchase the volume of FTRs it seeks via those auctions.

As a result, using FTRs to cover Meridian's peak market exposures is not feasible or realistic without incurring considerable cost. Having said this, Meridian is a large participant in the FTR market and the graph below shows how Meridian built its June 2016 FTR position.

Figure 1 - Meridian's FTR purchases for June 2016



Graph: FTR acquisitions over time for June 16 - Meridian held a total of 133.5MW of FTRs between BEN and the NI

NOTE: An HVDC filter bank outage during June constrained FTR auction volumes while increasing the risk of payment curtailment for FTR holders.

Finally, there are alternate products and product markets available to manage peak exposures like those observed on 2 June 2016. The "Over the Counter" market is one example and Meridian regularly uses that market at short notice to manage peak exposures.

2. *Can Meridian outline the actions that their traders are expected to take when they observe price separation between the north and south islands in the pre-dispatch schedules or any other pre-dispatch indicators?*

As summarised below, forecast price separation between NI and SI, as captured in pre-dispatch schedules, drives a number of responses from Meridian's spot traders.

In general the spot traders are able to use forecast HVDC flows as an indicator of potential price separation.[1] When the HVDC is in constraint, the nodal pricing market sends the appropriate signals to lower generation on the sending end, or increase generation on the receiving end. Meridian responds to those pricing signals.

a. *If the actions include offer changes, how many times in the year before 2 June 2016 has Meridian responded to price separation between the islands by changing its offers?*

Meridian's spot traders have responded to forecast[2] (or possible) price separation between the islands on many occasions by changing its offers as forecast (or possible) price separation can be a significant exposure for Meridian. Meridian constantly manages it generation offers to manage flows over the HVDC link.

At the same time, Meridian has been exposed to price separation that is observed after "gate closure". It has also purchased hedges that were not required due to forecast uncertainty.

Meridian has also sought hedges from the Over the Counter market on a number of other occasions in the year before 2 June 2016.

3. *Did Meridian know it was net pivotal in one or both Islands on 2 June 2016?*

. All decisions are made on the basis that Meridian is operating in a competitive environment and that competitors may and will make decisions that affect final prices and final cleared quantities of generation and the choices made by spot traders.

As shown in the table in **Appendix One** and the bullet points below, the assumption that there was a competitive environment during the evening of 2 June was correct. Specifically, Meridian did not set the price in any of the three trading periods in question and on review there was competitive interaction between offers from Whirinaki and

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[1] In the face of multiple sources of uncertainty in the market there is always a distinction between what is forecast and what is possible – traders are always expected to undertake second-order thinking around what prices may eventuate under various circumstances, not just to take a forecast as a given – this can be as important, or even more important, to decision-making than what has been shown in a forecast.

[2] Note, Meridian uses the Non Responsive Schedule Short (NRSS) as the reference tool for Appendix One. Meridian finds the Price Responsive Schedule Short (PRSS) to be insufficiently reliable to use as a primary forecasting tool in these circumstances. For example, on 2 June the PRSS schedule did not show the high prices that eventuated until 5pm.

Waikaremoana and forecast vs. actual consumption in those trading periods. The extract of trading information from 2 June 2016 below shows the following in relation to TP 36 - TP 38 (see **Appendix One**):

- TP36: Prior to gate closure, forecast prices for TP36 were in the order of \$200/MWh in the NI and \$170/MWh in the SI. Meridian made no adjustments to its offer on gate closure and it wasn't until after gate closure that prices lifted to \$4,875/MWh and \$4,235/MWh in the NI and SI respectively. That is where they settled. Meridian assumed at the time of gate closure that prices would form at the lower forecast price level (i.e. ~\$200/MWh in the NI and ~\$170/MWh in the SI). The events that drove that pricing were entirely outside of Meridian's control and occurred after gate closure.

- TP37: Prior to gate closure, forecast prices for TP37 were \$5,266/MWh and \$4,258/MWh in the NI and SI respectively. Meridian made no adjustments to its offers on gate closure. Final prices were settled at \$196 and \$159 in the NI and SI respectively.

- TP38: Prior to gate closure, forecast prices for TP38 were approx. \$200/MWh in the NI and \$170/MWh in the SI. Meridian made a small adjustments to its offer on gate closure (it moved more energy into a price tranche below \$200/MWh). After gate closure price forecasts lifted to between \$3,159/MWh and \$4,875/MWh in the NI and \$2,600/MWh and \$3,519/MWh in the SI. Final prices settled at \$3,250/MWh and \$2,791/MWh. Meridian assumed at the time of gate closure that prices would form at the lower forecast price level (i.e. ~\$200/MWh in the NI and ~\$170/MWh in the SI). Again, the events that drove that pricing were outside of Meridian's control.

- None of the final prices in any of those periods were set by Meridian.

a. *Can you provide data to support your answer? We are specifically interested in trading period level data on all profit items along with any assumptions that you need to make.*

In addition to the data set out above, and **Appendix One**, we include Figure 2 below to demonstrate that Meridian's offers did not set the final price in any trading period. This table shows that Genesis's Tuai offer set the price for TP36 and Contact's Whirinaki offer set the price for TP38.

Figure 2 - Final prices at nodes showing offers that set the final price

TRADING DATE	TRADING PERIOD	AVI2201	BEN2201	OHA2201	OHB2201	OHC2201	WTK2201	HLY2201	TUI1101	WHI2201	SFD2201	MTI2201	WKM2201
2/06/2016	36	4225.76	4235.96	4215.11	4223.2	4223.25	4231.95	4713.54	4600.07	4618.42	4654.72	4546.21	4565.96
2/06/2016	37	158.78	159.13	158.31	158.62	158.63	159.04	189.5	185.07	186.11	185.05	183.21	184.01
2/06/2016	38	2785.65	2791.79	2777.35	2782.74	2782.9	2790.14	3149.66	2987.27	3000	3106.66	3006.43	3019.49
2/06/2016	39	161.13	161.48	160.89	160.96	160.97	161.39	185.01	180.77	181.49	176.66	178.67	179.45
2/06/2016	40	139.19	133.42	125.53	126.18	127.49	143.74	154.82	155.07	151.88	145.74	149.53	150.18

b. *Meridian does not seem to hold FTRs commensurate with the basis risk associated with having a large amount of generation in the South Island and load spread approximately evenly between the islands. Can Meridian explain its FTR position relative to its underlying basis risk?*

As summarised above, Meridian uses FTRs, alongside other financial instruments and its generation assets, to manage its market exposures. In the case of FTRs, they are typically used to manage baseload risk.

As described above, the FTR auction is a competitive process and Meridian does not always secure the FTR volume it seeks. However, when this occurs Meridian considers other parties have overpaid for those FTRs and instead it considers alternate choices for managing that risk.

4. *Does Meridian believe that the events of 2 June 2016 constitute a UTS, and if not, why not?*

No.

Meridian's decision making was a rational and measured response to risk consistent with behaviour that would be expected in a competitive market. Meridian offered generation which covered its contracted position at below the final dispatched price, and it did not set the prices.

Moreover, there was no loss of confidence in the market nor any risk of that occurring.

Meridian is able to make this statement as changes in levels of confidence can be identified from two sources. First, it can be assessed quantitatively by examining the response of forward markets like the ASX that rely on spot market prices to settle contracts. Second, it can be assessed by participant reaction.

Meridian has completed quantitative analysis to assess whether there was an impact on forward market confidence following the 2 June. That analysis shows that there was none. Specifically:

- the ASX operated normally on 3 June and in the days following that – participation was as expected, the bid/ask spread for market products was not impacted and prices for products in future periods (i.e. Q3 2016) did not lift. Rather Q3 2016 fell in the days following 2 June.
- there was an FTR auction in the week following 2 June. Meridian again analysed reaction in that auction and could not identify any sign that suggested a loss in confidence.
- Meridian cannot quantitatively analyse participation in Over the Counter markets as it does not have all the data required but it has been able to buy and sell products in those markets without challenges relating to confidence. In particular, Meridian has continued to receive offers of Over the Counter products at reasonable prices which would suggest the events of 2 June have had no impact on confidence. An example of a recent offer is attached at **Appendix Two**.

This analysis confirms that forward markets remain confident in the spot market formation process, and is markedly different to analysis of the events following the 26 March 2011 UTS.

While Electric Kiwi has claimed a UTS occurred, wider market participant reaction demonstrates that confidence has not been affected. In fact, another smaller retailer, Flick Electric, has publicly commented that it does not have any concerns with the trading on 2 June:[5]

> *"Flick Electric, a rival minnow retailer whose customers would have felt the main brunt of the price spike, is not taking any action and says it's "pretty comfortable" both with the way the wholesale electricity market worked that day and the tools it gives customers to manage such price spikes."*

On 8 June Flick also offered a Winter Price guarantee to its customers.[6] This demonstrates ongoing confidence is retained by other market participants and again is in marked contrast to the events that followed 26 March 2011 where many participants filed UTS claims.

5. *Does Meridian believe that the events of 2 June 2016 are consistent with the standards of good trading conduct?*

   Yes we do.

   The requirement in the Code (cl 13.5A) is that generators must ensure that their conduct in relation to offers and reserve offers is consistent with a high standard of trading conduct. We believe our conduct has at all times been consistent with a high standard of trading conduct.

   - As indicated above, Meridian raised its peak offers early in the day on 2 June in response to the lack of NI wind and the clear possibility of price separation between NI and SI. This gave other parties a chance to react and likewise change their offers.

   - We increased our offer prices in order to mitigate the clear risk of significant loss to Meridian arising from the price separation. Furthermore the increased offer prices were consistent with offers already in place from other generators in the NI (i.e. Meridian did not 'set' the market price).

   - Lastly the volume of generation we moved into higher priced offer tranches was no more than was necessary to address the risk of loss to Meridian arising from the price separation.

6. *Does Meridian believe that the events of 2 June 2016 fall within the safe harbour provisions as set out in 13.5B of the Electricity Industry Participation Code 2010?*

   Yes, we do. While the safe harbour provisions are not well framed to deal with Meridian's circumstances, being pivotal in the SI for a large proportion of the time, but required to react competitively in the context of its total New Zealand market position, it will be apparent from the above outline of events that Meridian offered in respect of all of its capacity, revised its offer as soon as it could, and Meridian's offers did not result in a material increase in final prices (eg in TP 36 and TP 38), as compared to trading periods in which Meridian had taken the same actions and prices were lower (eg TP 37).

Please feel free to contact Jason Woolley if you require anything further.

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[5] Smellie, P. (21 June 2016). Electric Kiwi seeks disciplinary action against Meridian for price spike. National Business Review. Retrieved from: http://www.nbr.co.nz/article/electric-kiwi-seeks-disciplinary-action-against-meridian-price-spike-b-190609

[6] Winter Savings Guaranteed. Written by Flick Electric Co 8 June 2016. Retrieved from: http://news.flickelectric.co.nz/winter-savings-guaranteed/

Kind regards,

Mike Roan
Manager Wholesale Markets and Production

meridian

APPENDIX ONE

2 June Price Schedules

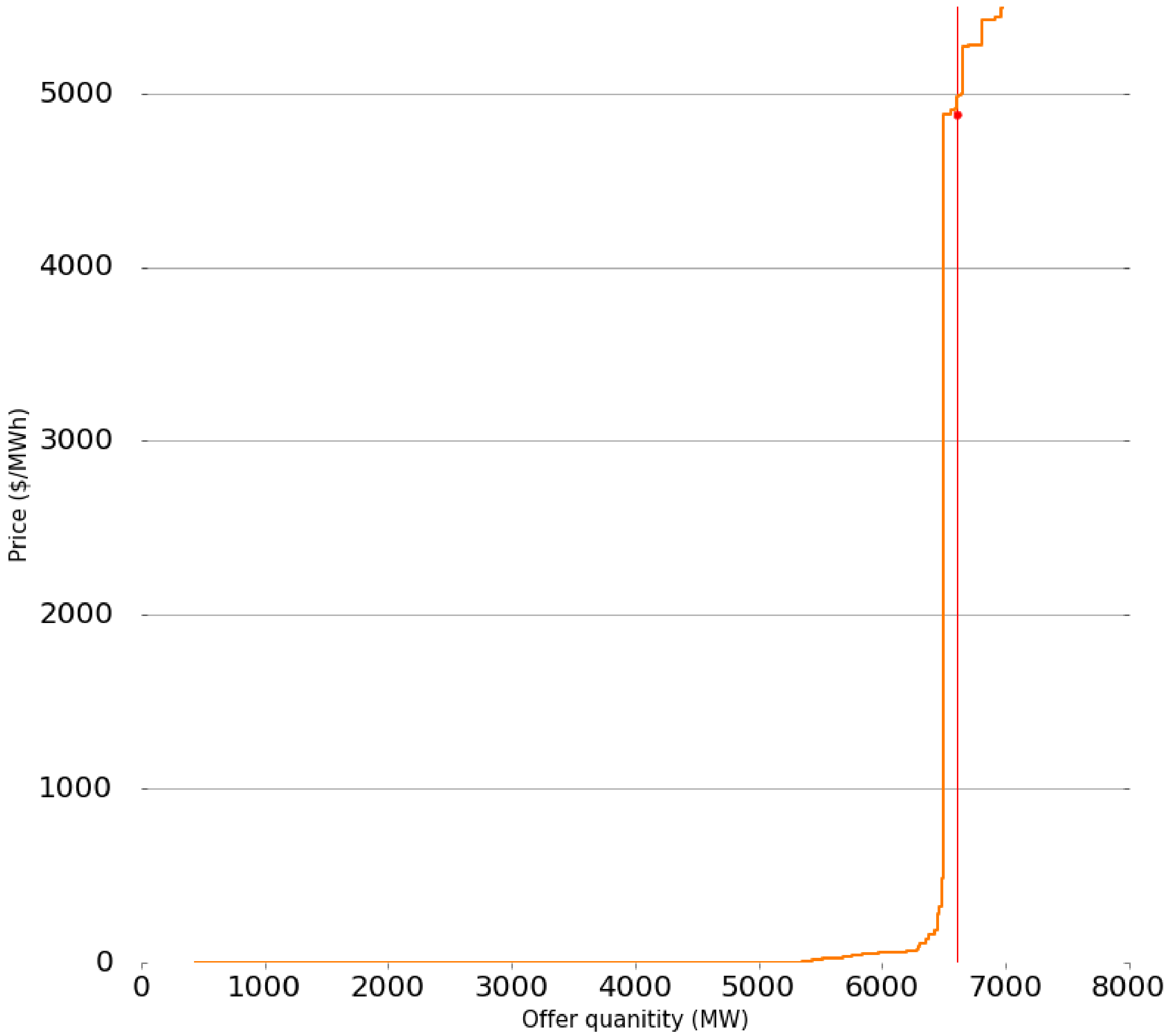
					Meridian Offer changes						Meridian Offer changes						Meridian Offer changes			
Schedule	Run Time	TP	OTA	BEN	<$200	<$1000	<$5000	TP	OTA	BEN	<$200	<$1000	<$5000	TP	OTA	BEN	<$200	<$1000	<$5000	Competitor observations
Long	12:10:05 a.m.	36	299.79	49.6				37	299.93	34.53				38	234.36	38.4				
Long	2:10:03 a.m.	36	330.96	49.6				37	5411.57	40.07				38	348.12	40.02				
Long	4:10:04 a.m.	36	324.46	49.6				37	5411.27	40.07				38	348.12	40.07				
Long	6:10:04 a.m.	36	232.09	50.89	-50	-50		37	321.37	36.62	-60	-60		38	232.46	40.07	-60	-60		
Long	8:10:04 a.m.	36	232.09	63	-5	-5		37	234.38	38.4				38	232.09	38.35				
Long	10:10:03 a.m.	36	5409.05	40.04	-175	-15	-205	37	5415.91	29.17	-306	-15	-321	38	318.98	30.08	-301	-15	316	Whirinaki 52MW tranche price raised to $5k
Long	12:10:03 p.m.	36	5407.98	4257.11	-10	-30	-20	37	5407.69	4257.11	-3	-30	-33	38	5408.77	4257.11	-32	-30	-62	
Long	2:10:03 p.m.							37	5359.87	4326.56	-58		-58	38	205.75	166.54				
Short	2:03:00 p.m.	36	205.72	166.14	-9		-9													
Short	2:33:01 p.m.	36	203.95	119.14	-52		-52	37	5411.35	42.26	-59		-59							
Short	3:03:00 p.m.	36	203.84	167.84				37	5267.29	4258.12				38	205.42	166.06				Waikaremoana 62MW tranche price raises to $4600 TP36
Short	3:33:00 p.m.	36	5066.33	4138.55				37	5266.75	4258.12				38	278.65	225.83				Whirinaki 52MW tranche price drops to $3900 TP37/38
Short	4:03:01 p.m.	36	4876.07	3982.79				37	209.48	169.35				38	200.47	162.47	-20		-20	Waikaremoana 62MW tranche price raises to $3500,
Short	4:33:00 p.m.	36	279.25	228.04				37	201.06	162.5				38	193.36	157.29				Whirinaki 52MW drops to $3000 TP38
Short	**4:40:42 p.m.**	36	5407.07	4268.88				37	4225.93	3478.62				38	3965.61	3205.95				Mangahao station trip sees special NRSS run
Short	5:03:00 p.m.	36	5406.46	4260.7				37	4245.48	3501.89				38	4224.18	3479.08				
Short	5:33:00 p.m.	36	5408.3	4260.7				37	4274.63	3635.65				38	4223.17	3519.57				
Short	6:03:00 p.m.							37	106322.5	4011.91				38	4238.27	3532.17				
Short	6:33:00 p.m.													38	3159.28	2643.25				
Final prices:		36	4,875.79	4,235.96				37	196.12	159.13				38	3,250.47	2,791.79				
Set by:			Tuai $4600.07						Tuai $185.07						Whirinaki $3000					

Appendix C Analysis of trading conditions during TP 35-40 on 2 June 2016

The offer curve was very steep, so small variations in demand or supply have a large effect on price

C.1 The spot market was tight, in the sense that small variations in demand could cause large changes in price. This is seen in TP37 which had much lower prices than TP36 and TP38.

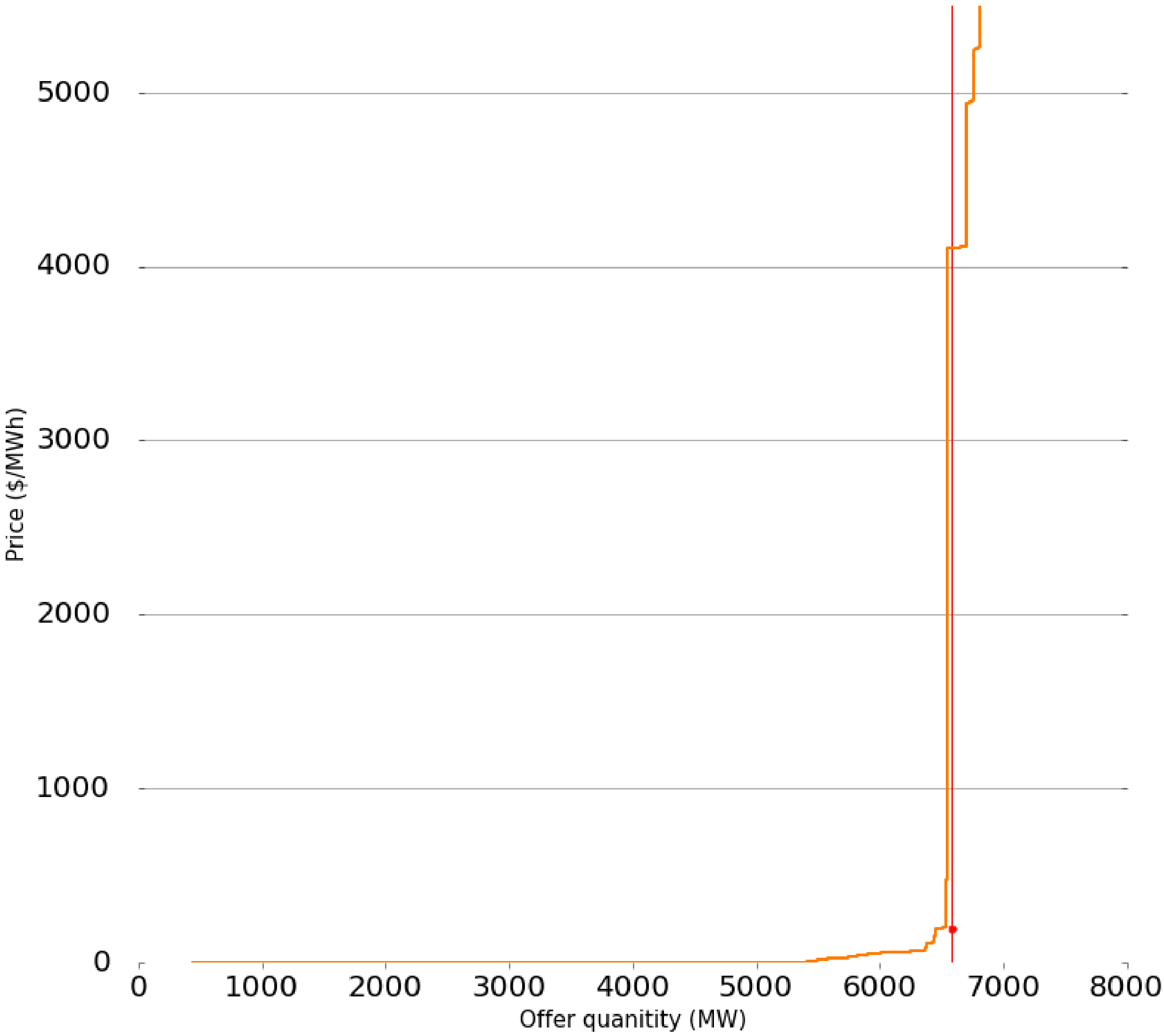
Figure 13: the offer curve for TP 36



Source: Electricity Authority

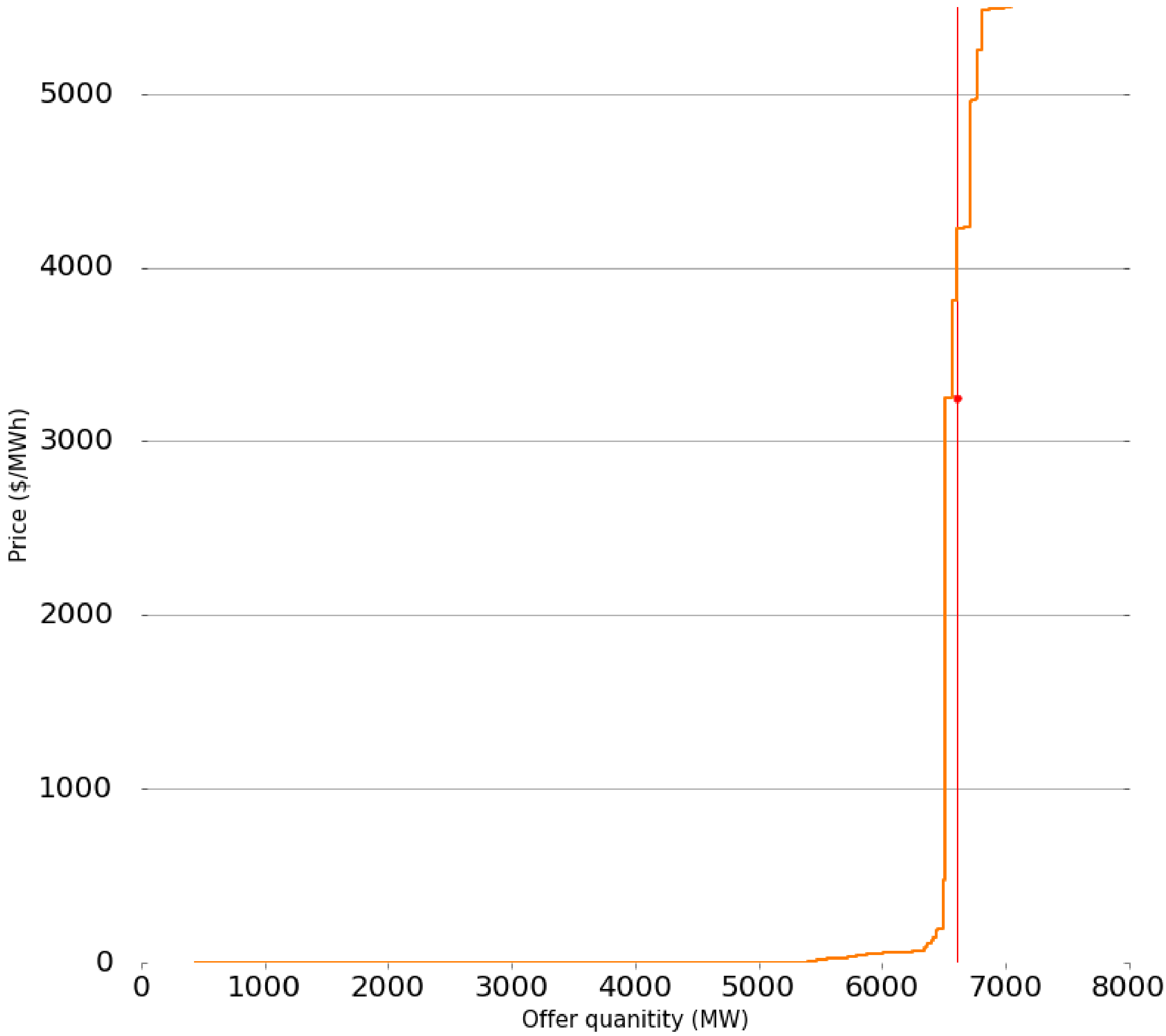
C.2 Figure 13 shows the offer curve for TP 36, demand (the vertical line) and the final price (the dot). Figure 14 and Figure 15 show the equivalent pictures for TP 37 and 38. These pictures show how steep the offer curve was and therefore how sensitive the price was to changes in demand. A small change in demand and offers caused the prices in TP 37 to be much lower than the prices in the adjacent trading periods.

Figure 14: the offer curve for TP 37



Source: Electricity Authority

Figure 15: the offer curve for TP 38

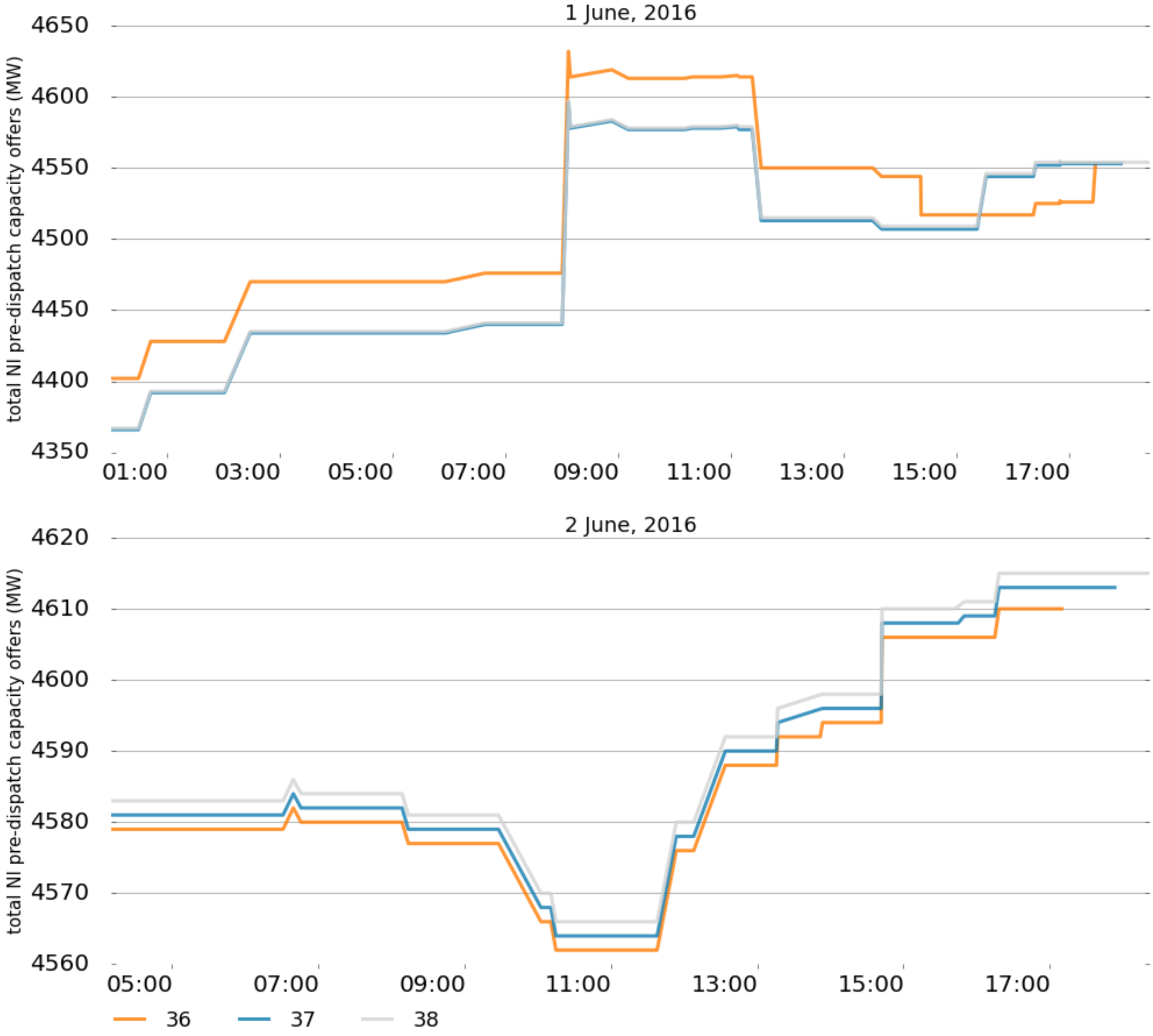


Source: Electricity Authority

Simulation shows how sensitive price was to changes in demand

C.3 The following analysis looked at what would have happened had demand been slightly different. It used the Authority's vSPD model and input data from each trading period. The simulation was done by changing the input data by very small amounts and observing what happened.

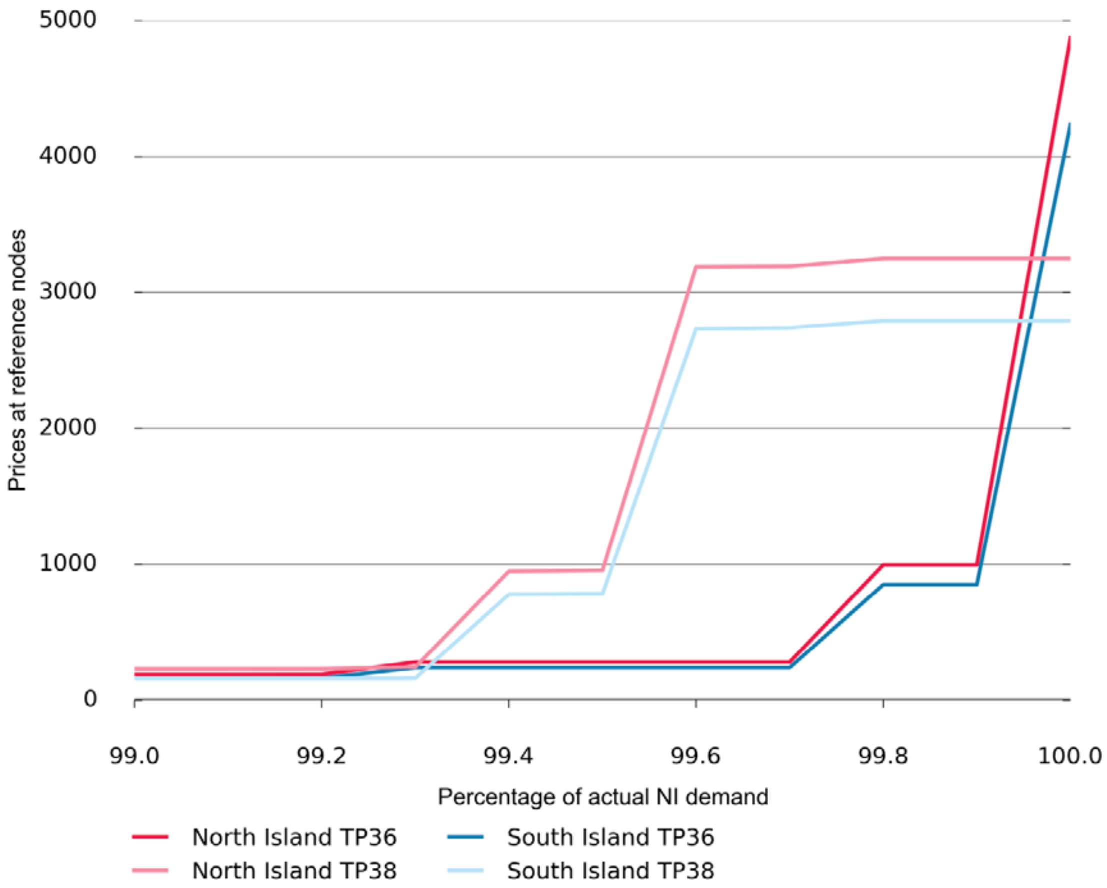
Figure 16: North Island Pre-dispatch capacity (energy and reserves) offers



Source: Electricity Authority

C.4 Figure 16 shows total capacity offered in the North Island for 1 and 2 June 2016. It is for three trading periods—TP 36 to 38—and traces the quantity of offers submitted up until real time using pre-dispatch data. It was calculated by adding energy and reserve (excluding interruptible load) offers. It showed that more capacity was offered on 2 June 2016 than on 1 June 2016. This suggests that it was the price of the offers rather than the quantity of offers that caused the high prices.

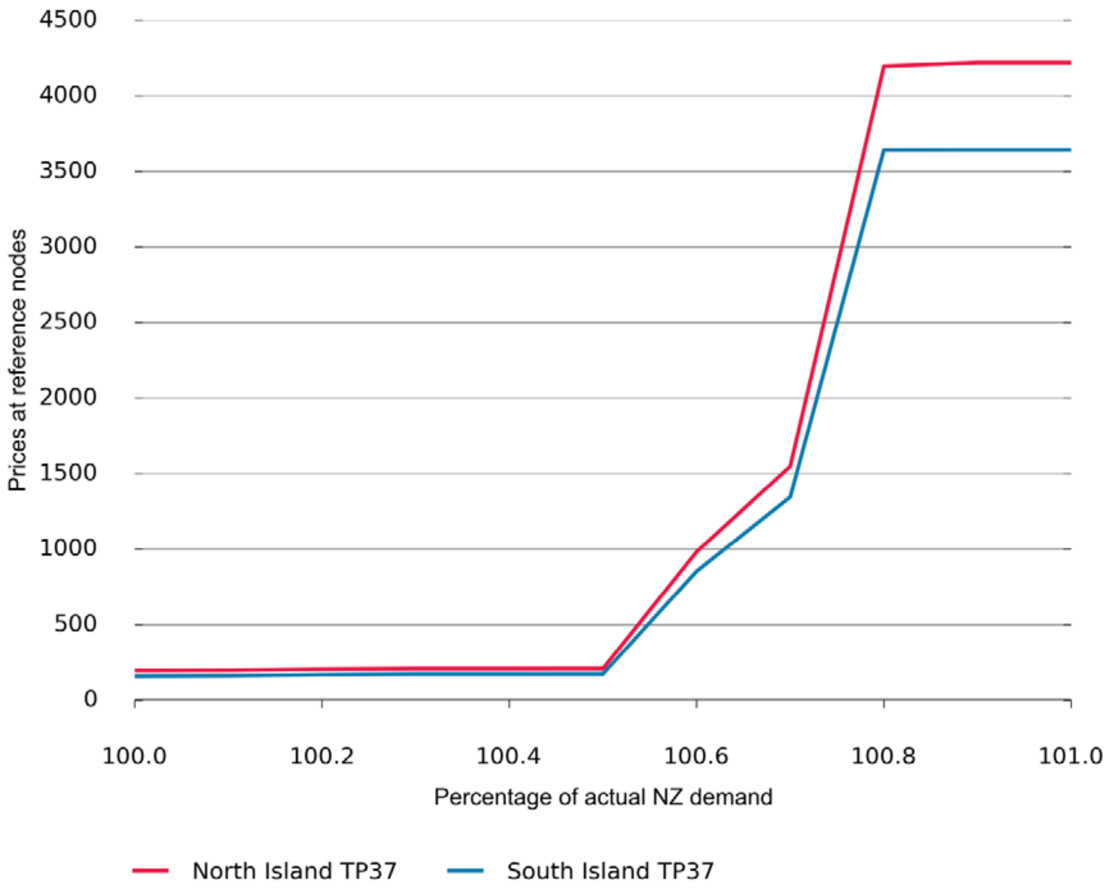
Figure 17: Sensitivity analysis using a decrease in demand



Source: Electricity Authority

C.5 Prices during TP 36 and 38 were highly sensitive to demand. Figure 17 shows what final prices would have been for TP 36 and 38 had North Island demand been slightly lower than actually occurred. A large effect in TP 36 can be seen with just a 0.1 per cent reduction in North Island demand. TP 38 has a similar large fall with a 0.5 per cent reduction in North Island demand.

Figure 18: Sensitivity analysis using an increase in demand



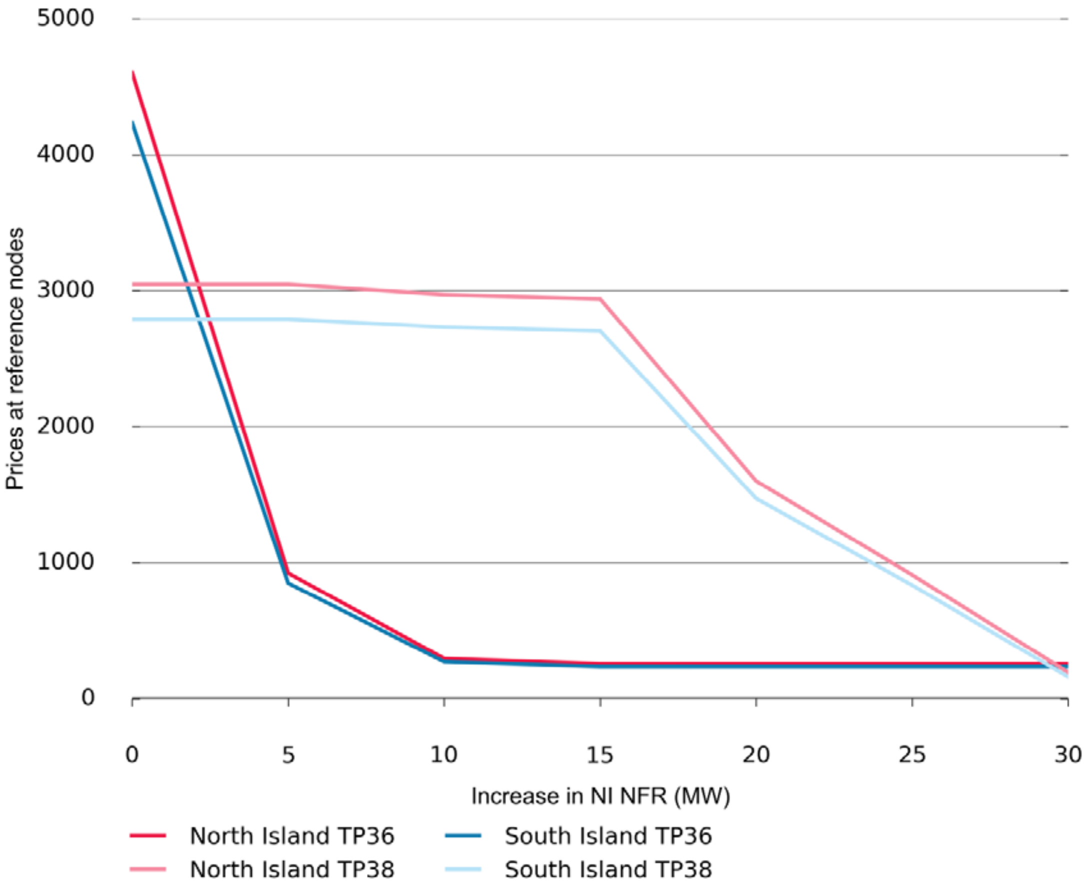
Source: Electricity Authority

C.6 Figure 18 shows TP 37, which had relatively normal prices. The chart shows what would have happened if New Zealand total demand had been slightly higher. There would have been a large increase in price if demand had been 0.8% higher. Again, this shows how sensitive the prices were to changes in demand.

Small increases in the quantity of North Island reserves would have substantially lowered prices

C.7 The analysis simulated what would have happened to final price if there were more reserves available. The simulation involved increasing the amount of Net Free Reserves (NFR) in the North Island, which is equivalent to adding additional low priced reserve into the North Island, ie, one MW of additional North Island NFR is equivalent to offering one additional MW of North Island reserve at an offer price of $0.

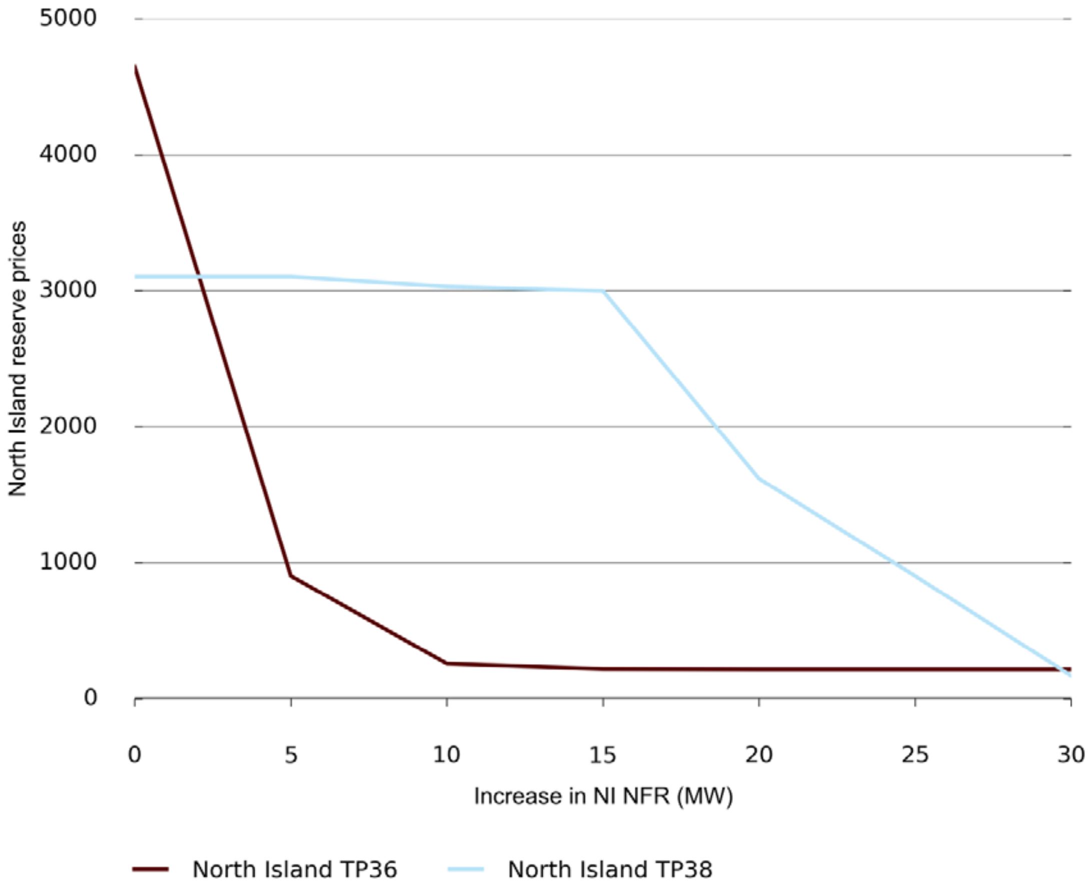
Figure 19: The effect of increasing North Island NFR on North Island energy prices



Source: Electricity Authority

C.8 Figure 19 shows the effect on energy prices of increasing NFR in the North Island (holding all else constant). Extra NFR would have tended to lower both reserve and energy prices because of the inter-relationship between the energy and reserve prices.

Figure 20: The effect of increasing North Island NFR on North Island SIR prices

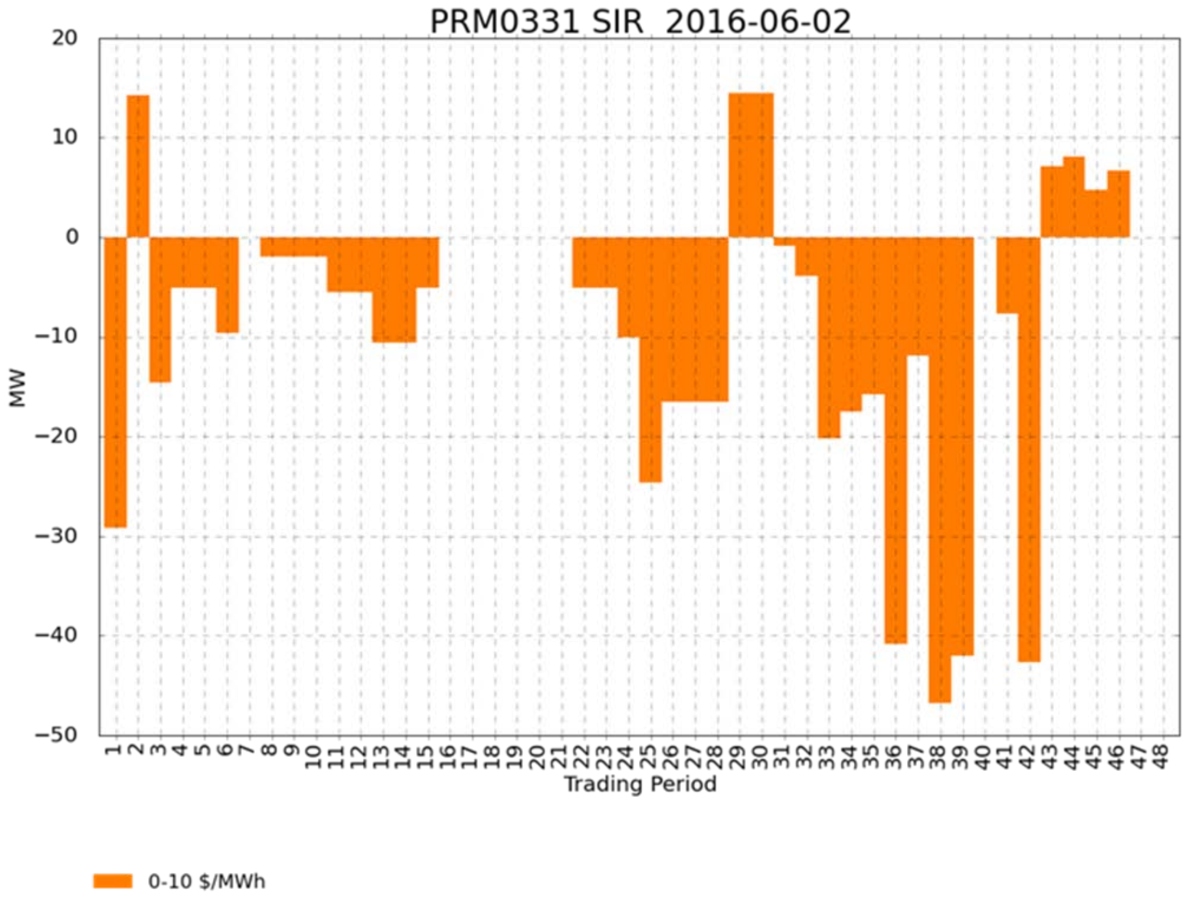


Source: Electricity Authority

C.9 Figure 20 shows the effect on sustained instantaneous reserve (SIR) prices of increasing NFR. The plot matches Figure 19 above, showing how SIR and energy prices were inter-related during TP 36 and 38.

While interruptible load reserve offers were withdrawn after gate closure, this appears to have been for *bona fide* reasons

Figure 21: Interruptible load offer changes at Paraparaumu on 2 June



Source: Electricity Authority

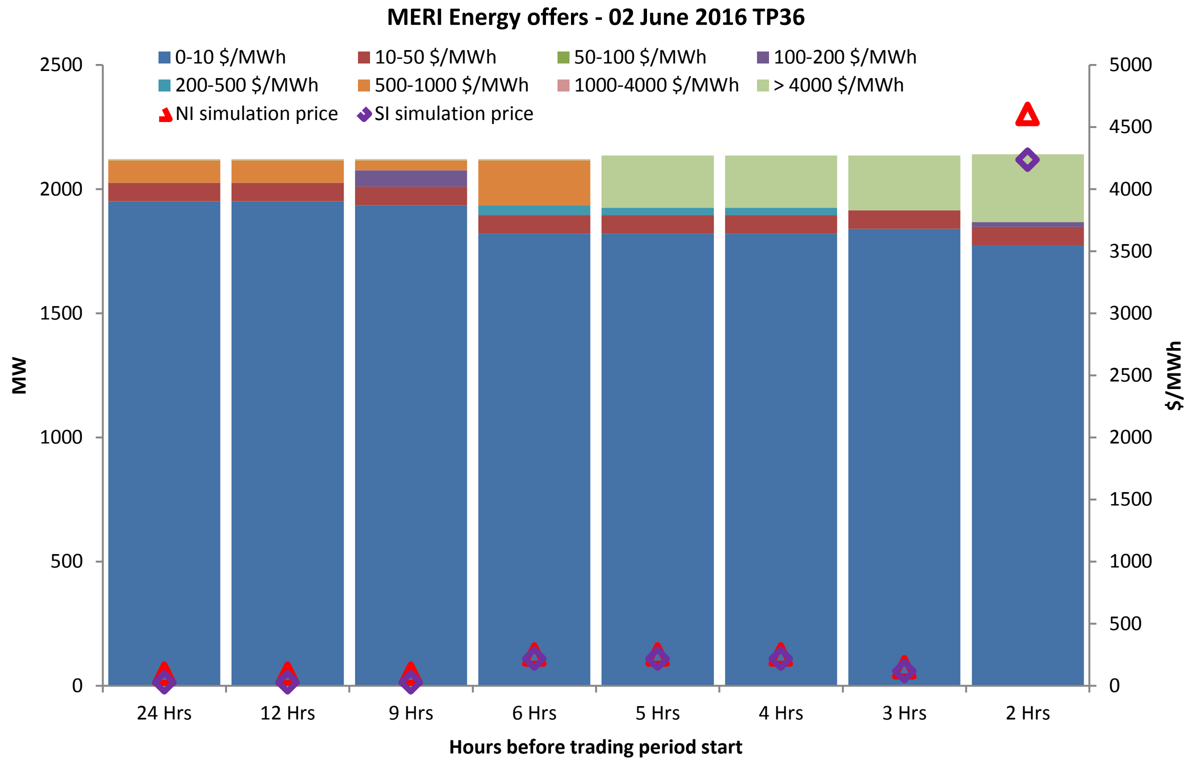
C.10 Figure 21 shows the difference between final NISIR offers (offers used in the final pricing solve) and offers that were live at the relevant gate-closure for each trading period, at the Paraparaumu grid exit point. Note that interruptible load can be offered at any point in the network. A negative number implies that an NISIR offer was reduced within the two-hour window between gate closure and real-time. Given the size of the offer changes, some *bona fide* reasons for such changes would be expected.

C.11 Based on the Authority's assessment of the 2-hour rule revision data provided to the Authority, Norske Skog and Pan Pac reduced their demand over TPs 35 to 39. A load reduction should also be accompanied by a reduction in reserve offers (since there is now less load available to provide reserves). It appears that the *bona fide* load reduction by Pan Pac, and Norske Skog's load reduction through its dispatchable demand offer, broadly matched the observed reduction in reserve offers—implying that the reduction in reserve offers was due to physical reasons and not through gaming of the reserve market.

Prices would have been substantially lower if Meridian had not changed its offers (all else being equal, which would have not been the case)

C.12 This analysis used Meridian's pre-dispatch offers and looked at what would have happened had it, or any other participant, not changed its offers. As with all similar simulations, the analysis assumed "all else being equal". In other words, that there would have been no changes to offers in response to the offer changes used in the analysis. In practice this was not the case, as other participants changed their offers after Meridian had changed its.

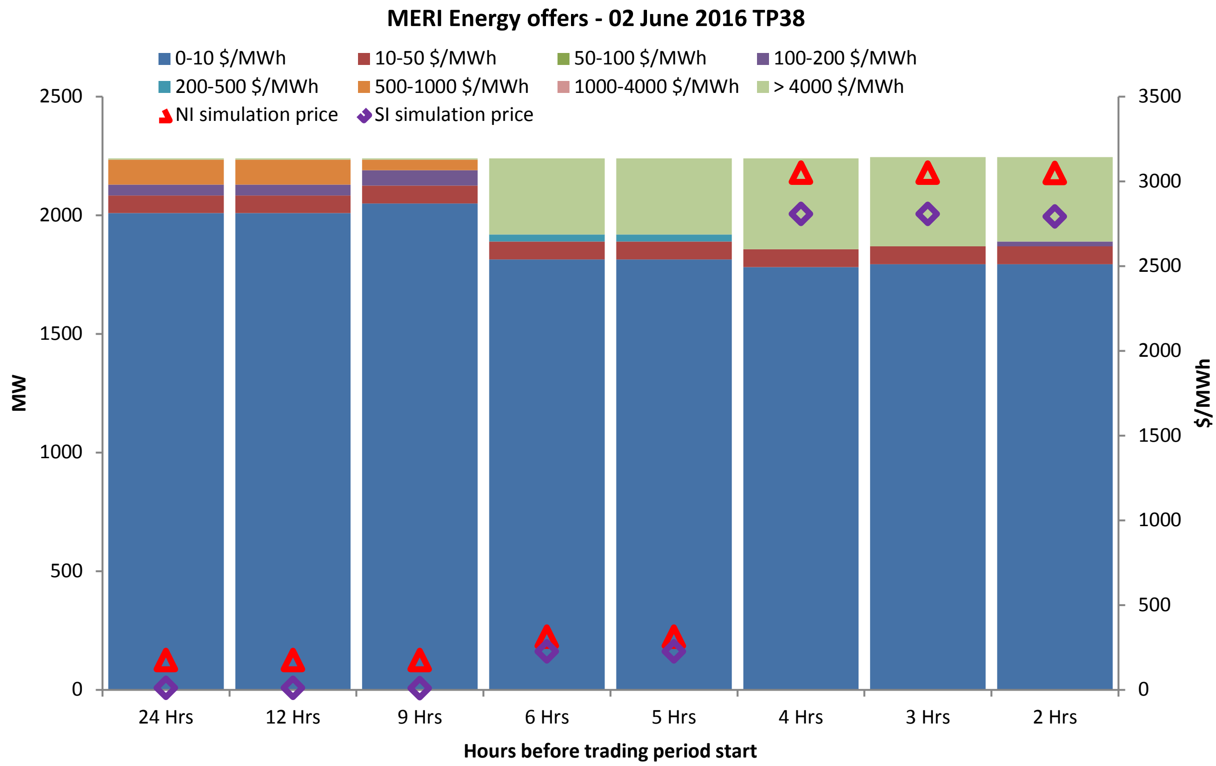
Figure 22: Meridian's offer changes for TP 36 and their effect on price



Source: Electricity Authority

C.13 Figure 22 shows Meridian's offer revisions up to gate closure for TP 36 (quantity is shown on the LHS axis, and the coloured bars show the allocation of this quantity against the offer prices in the legend) and the Authority's simulation of what final prices would have been in both islands, assuming all else was constant (RHS axis, individual markers). The offers shown in each bar are those that were used to calculate the simulated final prices. The chart shows that had Meridian's original offers been used, then final prices would have been substantially lower in both islands, although this may not have been apparent at the time the offer changes were made.

Figure 23: Meridian's offer changes for TP38 and their effect on price



Source: Electricity Authority

C.14 It is interesting that Meridian's main offer changes, five and six hours before the trading period, caused only a fairly modest increase in prices, while the final relatively minor offer changes just before gate closure are what caused the large increase in nodal prices. This was due to the extreme sensitivity at the top end of the combined offer curve (see Figure 13 through Figure 15).

C.15 Figure 23 shows the situation in TP 38 and shows a similar set of circumstances to Figure 22 above: Meridian's earlier offers would have meant lower prices in both islands.

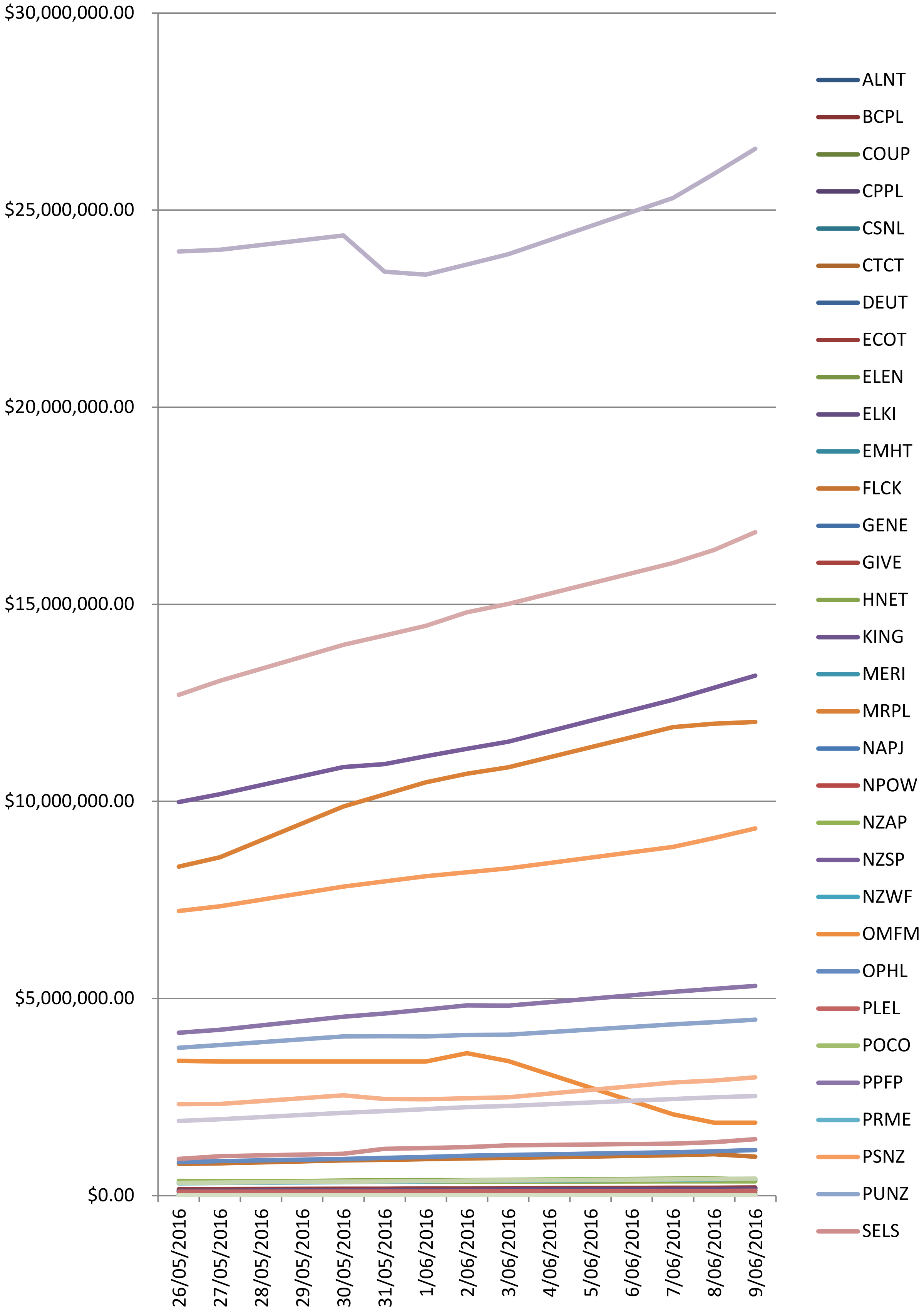
Appendix D Analysis of market operations indicators

Prudential requirements show no material changes

D.1 Prudential requirements are calculated daily by the clearing manager. Figure 24 shows the prudential calculations for the period one week before to one week after 2 June 2016. With the exception of OM Financial (denoted as OMFM in the Figure) the prudential requirements of the participants showed a steady increase consistent with normal operations.[25] There is no indication that the situation of 2 June 2016 caused an unusual increase in prudential for any participant, or that any participants have made any significant changes to their market positions.

25 OMFM only trade FTRs through the clearing manager so their prudential requirements follow their FTR auction results rather than electricity purchases.

Figure 24: Prudential requirements before and after 2 June 2016



Source: Electricity Authority

FTR trading appears to have been unaffected

D.2 FTR auctions for June 2018 were completed mid-month in April, May and June 2016. The bids that cleared for the June 2018 period are shown in Table 3. Analysis shows bidding behaviour in June 2016 was reasonably consistent with the bidding behaviour in the April and May auctions. This indicates that, at that time, FTR participants did not expect there would be out-of-the-ordinary price separation in June 2018, ie, the auction results did not suggest that participants expected greater degrees of price separation to occur in the future as a result of the situation on 2 June 2016.

Table 3: FTR auction results for the June 2018 period

StartDate	HedgeTyp	Source	Sink	PRI_APR_2016	PRI_MAY_2016	PRI_JUN_2016	Trendline
1/4/2018	OPT	BEN	HAY	$3.16	$3.22	$3.33	
			INV	$3.80	$4.19	$3.71	
			ISL	$4.22	$4.61	$3.92	
			OTA	$7.18	$7.66	$7.84	
		HAY	BEN	$0.68	$0.50	$0.51	
			OTA	$4.01	$4.44	$4.51	
		INV	BEN	$1.97	$2.45	$2.38	
			HAY	$5.14			
			ISL	$3.29	$3.89	$3.49	
		ISL	BEN	$0.03	$0.01	$0.01	
			INV	$0.93	$1.03	$0.91	
		OTA	BEN	$1.51	$0.91	$0.91	
			HAY	$0.83	$0.41	$0.40	
1/5/2018	OPT	BEN	HAY	$3.12	$3.05	$3.27	
			INV	$3.90	$4.20	$3.64	
			ISL	$4.40	$4.81	$3.92	
			OTA	$7.13	$7.49	$7.78	
		HAY	BEN	$0.35	$0.39	$0.31	
			OTA	$4.01	$4.44	$4.51	
		INV	BEN	$2.11	$2.37	$2.26	
			HAY	$5.24		$5.54	
			ISL	$3.54	$3.99	$3.42	
		ISL	BEN	$0.03	$0.02	$0.01	
			HAY		$3.07		
			INV	$0.96	$1.03	$0.89	
		OTA	BEN	$0.75	$0.82	$0.75	
			HAY	$0.39	$0.43	$0.44	
1/6/2018	OPT	BEN	HAY	$3.00	$2.95	$3.21	
			INV	$3.77	$4.36	$3.59	
			ISL	$4.33	$4.96	$4.23	
			OTA	$7.34	$7.67	$7.93	
		HAY	BEN	$0.43	$0.45	$0.38	
			OTA	$4.34	$4.72	$4.71	
		INV	BEN	$2.16	$2.41	$2.20	
			HAY			$5.41	
			ISL	$3.62	$4.06	$3.71	
		ISL	BEN	$0.03	$0.01	$0.01	
			INV	$0.92	$1.07	$0.88	
		OTA	BEN	$0.90	$0.89	$0.80	
			HAY	$0.47	$0.44	$0.42	

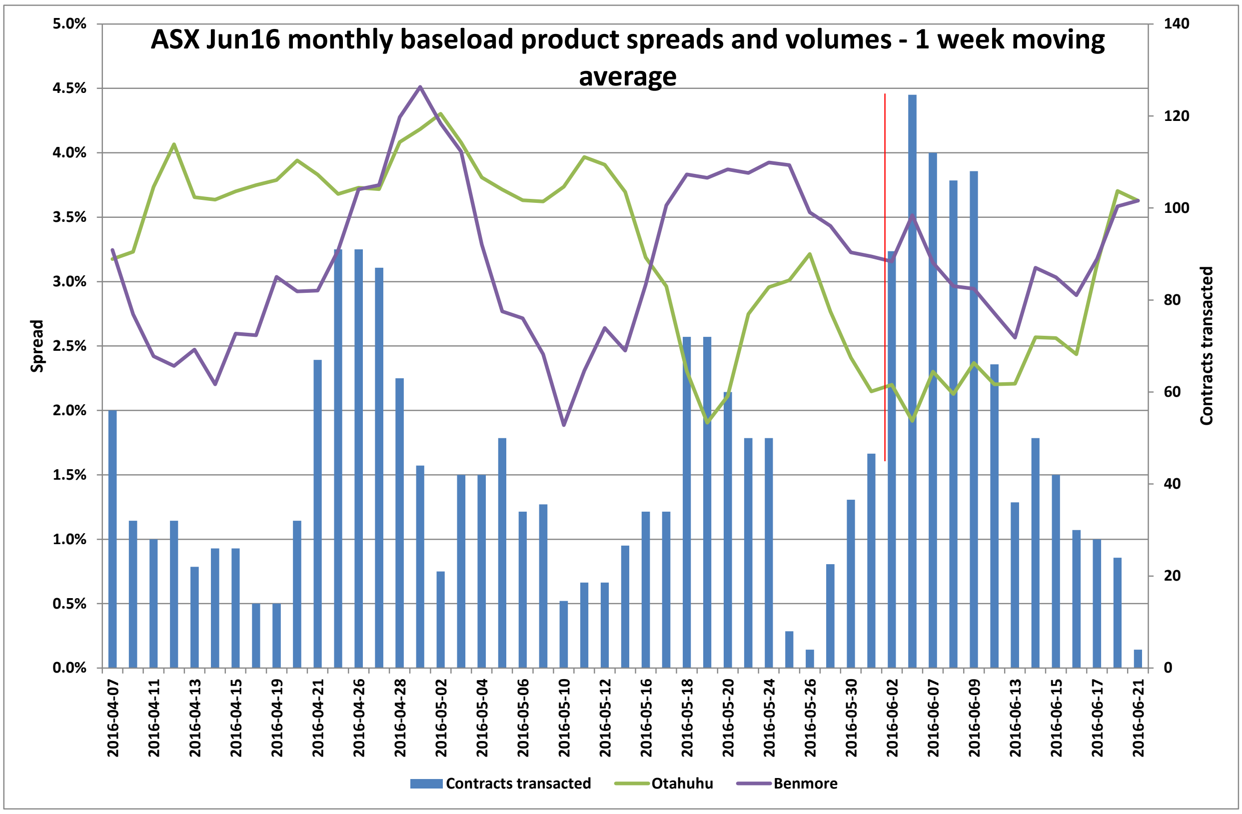
Source: Electricity Authority

Trading in the ASX market does not appear to have been affected

D.3 The Authority analysed trading activity on the ASX New Zealand Electricity futures and options market leading up to and following 2 June 2016. The series of graphs presented below show how various aspects of the market behaved.

D.4 Figure 25 shows the bid/ask spread for monthly baseload futures at both Otahuhu and Benmore and the number of contracts traded daily, and a one week moving average. The highest transaction levels occurred after 2 June 2016.

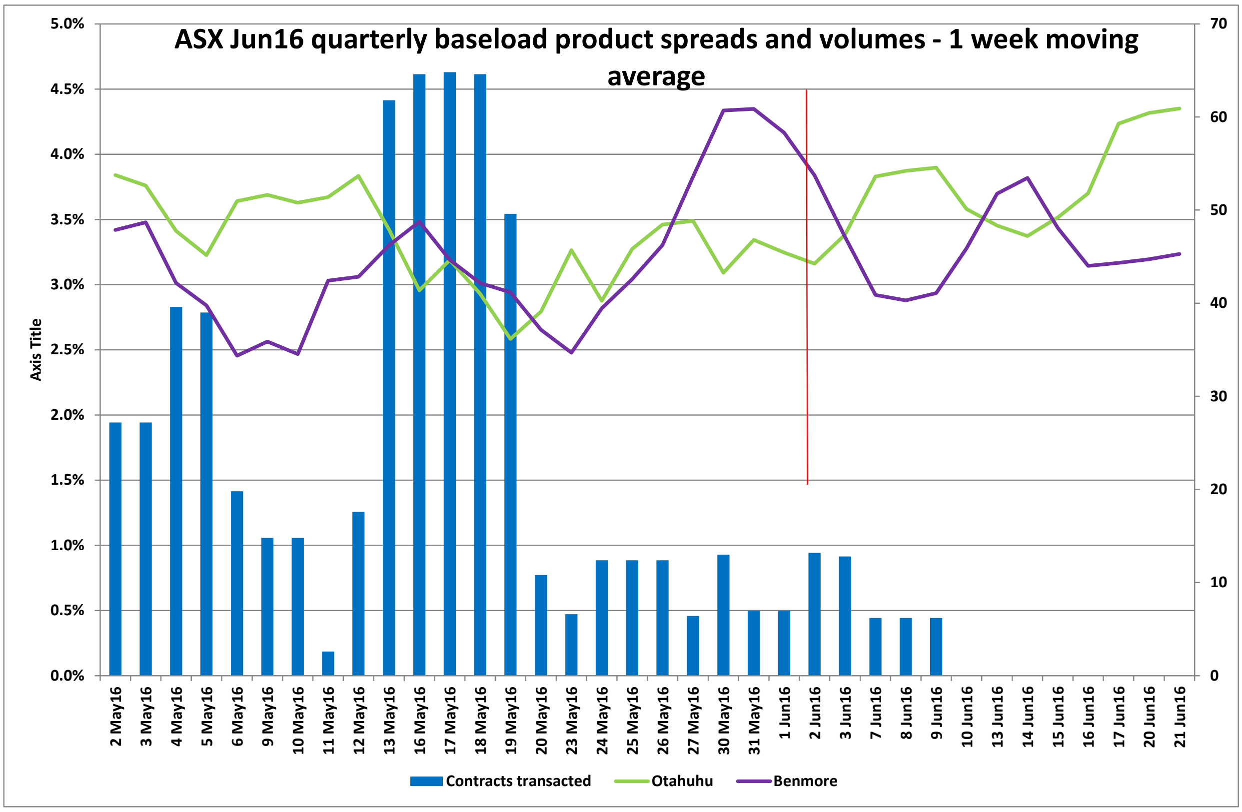
Figure 25: ASX monthly baseload futures trading for June 2016 before and after 2 June 2016



Source: Electricity Authority

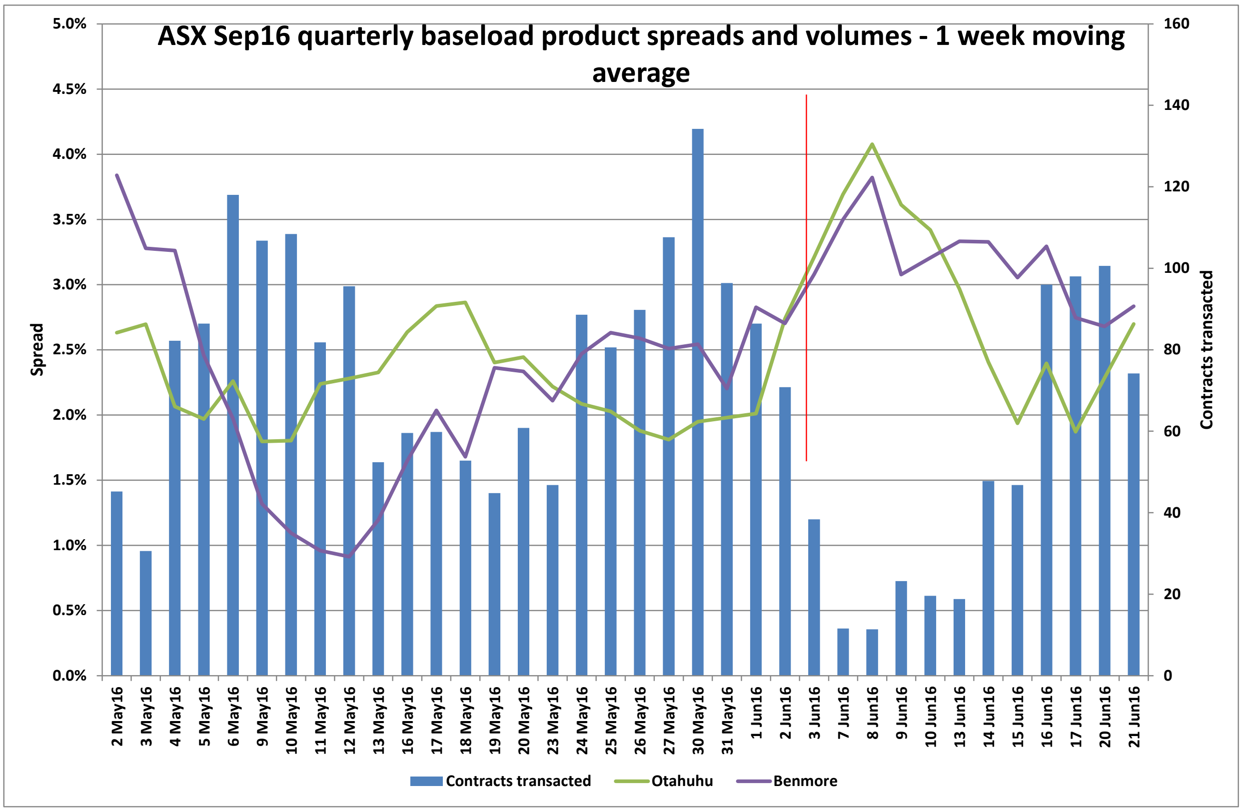
D.5 Figure 26 and Figure 27 show the same metrics for the trading of the quarterly baseload products for the June 2016 and September 2016 quarters respectively. Transaction levels for the June 2016 contracts fell away in a normal manner as the end of the quarter neared. The June 2016 monthly product (Figure 25) was transacted more as the June 2016 quarterly product transacted less, as is expected as the quarter progresses. At the same time, the September 2016 baseload products continued to transact in a normal manner.

Figure 26: ASX quarterly baseload futures trading for June 2016 before and after 2 June 2016



Source: Electricity Authority

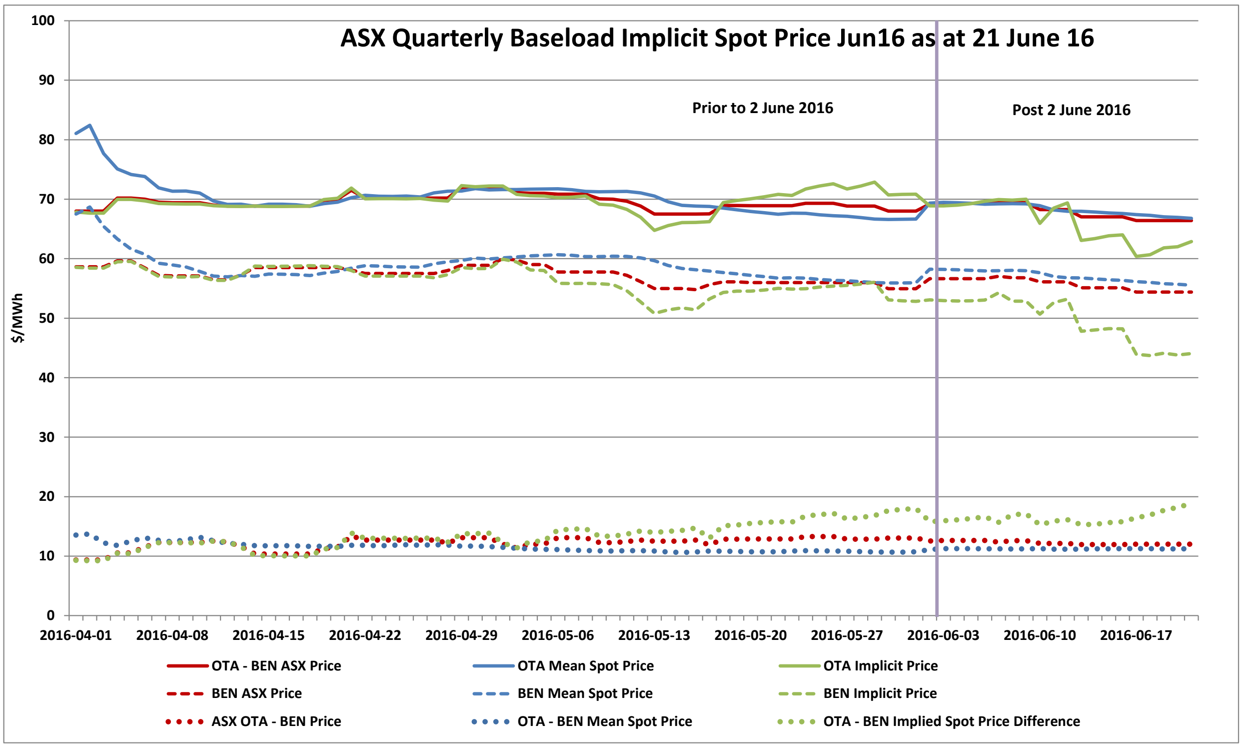
Figure 27: ASX quarterly baseload futures trading for September 2016 before and after 2 June 2016



Source: Electricity Authority

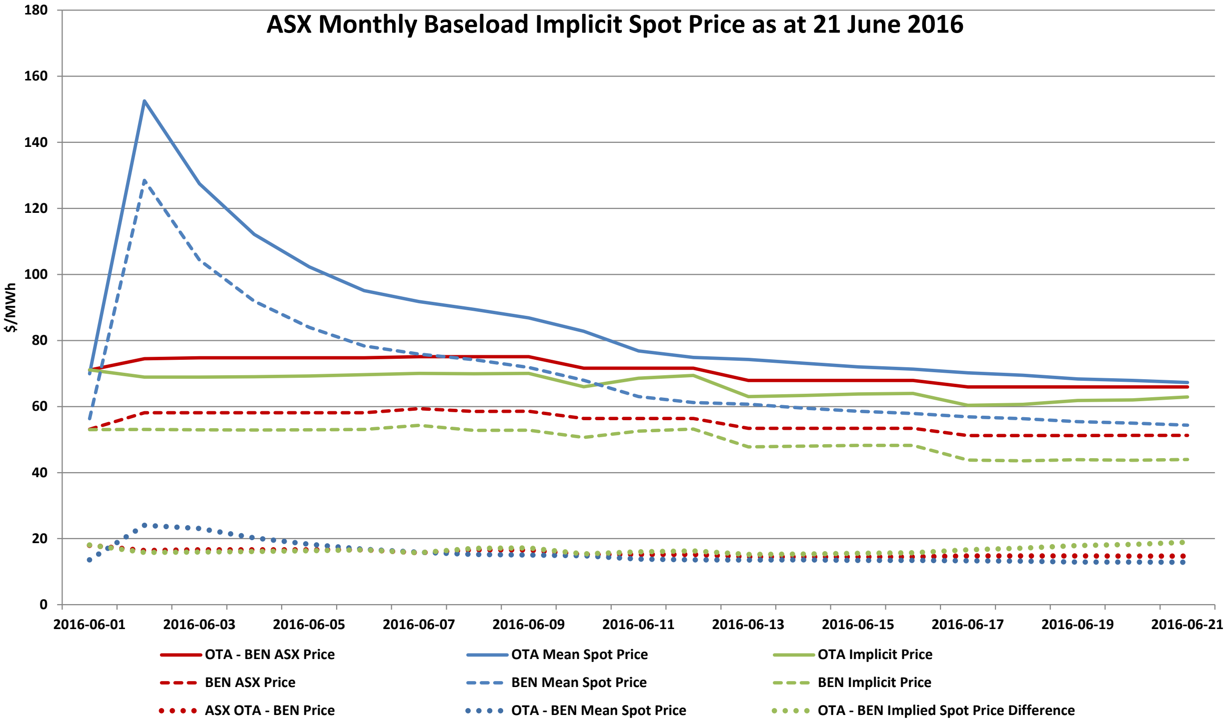
D.6 Figure 28 and Figure 29 show the implicit spot price differences between Benmore and Otahuhu using the ASX daily settlement prices for the June 2016 quarterly and June 2016 monthly contracts respectively. The implicit spot price differences for the two products were very similar for pricing through to the end of June. This suggested that participants were not expecting any further high price episodes.

Figure 28: Implicit spot price differences between Benmore and Otahuhu for ASX quarterly contracts for June 2016



Source: Electricity Authority

Figure 29: Implicit spot price differences between Benmore and Otahuhu for ASX monthly contracts for June 2016



Source: Electricity Authority

D.7 In summary, the indicators available in the ASX market did not provide any evidence that confidence in, or the integrity of, the wholesale market, had been affected by the events of 2 June 2016.

Appendix E Illustrative example of basis risk management around an export constraint through offer behaviour

E.1 An export constraint is a situation where there is too much power competing for too little load in a region, and there is insufficient transmission capacity to export the remainder. This situation should put downward pressure on prices in the exporting region; unless generators have sufficient ability to influence prices by re-structuring their offers.

E.2 In the example presented here:

(a) generator A is a renewable generator (low short-run marginal costs, or SRMC)

(b) generator B is a thermal generator

(c) region A is an export-constrained region.

E.3 This example highlights the salient features of basis risk between the South and North Islands.

Table 4: Hypothetical example of basis risk management through offer behaviour

Price taking generators offering at SRMC

Region 1 → **Region 2**

Transmission capability	20 MW
Amount transmitted	20 MW
Headroom	0 MW

Region 1			Region 2			Total	
Load in region 1	50 MW		**Load in region 2**	50 MW		Total load	100 MW
Generator A offers			Generator B offers				
Low priced generation	90 MW	@ $ -	Low priced generation	0 MW	@ n/a		
Hgh priced generation	0 MW	@ $ 89	Hgh priced generation	60 MW	@ $ 90		
Generator A quantity dispatched			Generator B quantity dispatched			Total quantity dispatched	
Low priced generation	70 MW	@ $ -				Low priced generation	70 MW
Hgh priced generation	0 MW	@ $ 89	Hgh priced generation	30 MW	@ $ 90	Hgh priced generation	30 MW
Undispatched offers	20 MW			30 MW		Undispatched offers	50 MW
Marginal price setter in Region 1	Generator A		Marginal price setter in Region 2	Generator B			
Price in Region 1	$ -		Price in Region 2	$ 90			

Price difference $ 90

Generators managing basis risk - tactic A

Region 1 → **Region 2**

Transmission capability	20 MW
Amount transmitted	20 MW
Headroom	0 MW

Region 1			Region 2			Total	
Load in region 1	50 MW		**Load in region 2**	50 MW		Total load	100 MW
Generator A offers			Generator B offers				
Low priced generation	69 MW	@ $ -	Low priced generation	0 MW	@ n/a		
Hgh priced generation	21 MW	@ $ 89	Hgh priced generation	60 MW	@ $ 90		
Generator A quantity dispatched			Generator B quantity dispatched			Total quantity dispatched	
Low priced generation	69 MW	@ $ -				Low priced generation	69 MW
Hgh priced generation	1 MW	@ $ 89	Hgh priced generation	30 MW	@ $ 90	Hgh priced generation	31 MW
Undispatched offers	20 MW			30 MW		Undispatched offers	50 MW
Marginal price setter in Region 1	Generator A		Marginal price setter in Region 2	Generator B			
Price in Region 1	$ 89		Price in Region 2	$ 90			

Price difference $ 1

Generators managing basis risk - tactic B

Region 1 → **Region 2**

Transmission capability	20 MW
Amount transmitted	19 MW
Headroom	1 MW

Region 1			Region 2			Total	
Load in region 1	50 MW		**Load in region 2**	50 MW		Total load	100 MW
Generator A offers			Generator B offers				
Low priced generation	69 MW	@ $ -	Low priced generation	0 MW	@ n/a		
Hgh priced generation	21 MW	@ $ 91	Hgh priced generation	60 MW	@ $ 90		
Generator A quantity dispatched			Generator B quantity dispatched			Total quantity dispatched	
Low priced generation	69 MW	@ $ -				Low priced generation	69 MW
Hgh priced generation	0 MW	@ $ 91	Hgh priced generation	31 MW	@ $ 90	Hgh priced generation	31 MW
Undispatched offers	21 MW			29 MW		Undispatched offers	50 MW
Marginal price setter in Region 1	Generator B		Marginal price setter in Region 2	Generator B			
Price in Region 1	$ 90		Price in Region 2	$ 90			

Price difference $ -

Generators managing basis risk - tactic B (prices *100)

Region 1 → **Region 2**

Transmission capability	20 MW
Amount transmitted	19 MW
Headroom	1 MW

Region 1			Region 2			Total	
Load in region 1	50 MW		**Load in region 2**	50 MW		Total load	100 MW
Generator A offers			Generator B offers				
Low priced generation	69 MW	@ $ -	Low priced generation	0 MW	@ n/a		
Hgh priced generation	21 MW	@ $9,100	Hgh priced generation	60 MW	@ $9,000		
Generator A quantity dispatched			Generator B quantity dispatched			Total quantity dispatched	
Low priced generation	69 MW	@ $ -				Low priced generation	69 MW
Hgh priced generation	0 MW	@ $9,100	Hgh priced generation	31 MW	@ $9,000	Hgh priced generation	31 MW
Undispatched offers	21 MW			29 MW		Undispatched offers	50 MW
Marginal price setter in Region 1	Generator B		Marginal price setter in Region 2	Generator B			
Price in Region 1	$ 9,000		Price in Region 2	$ 9,000			

Price difference $ -

E.4 The top example shows an initial case where generator A, located in the export-constrained region, offers all its generation at low prices, reflecting its low SRMC. Points of note in this example include that:

(a) the transmission system is constrained

(b) generator A is the marginal price setter in region 1. Generator B is the marginal price setter in region 2

(c) large price separation between the regions results due to the difference between the offer prices of the marginal generator in each island.

E.5 Under tactic A, generator A reduces its quantity offered in its low price band and moves this to a price just **below** the prices offered by generator B in region 2. Relevant notes include:

(a) the transmission system is still exporting 20 MW (but is congested, ie, no further generation can be exported)

(b) price separation is reduced because the difference in price between the two marginal generators is small

(c) generator A is still exposed to basis risk because, if generator B increased its offer price, price separation would result as in the case above. This is because prices in each region are being set by the local generation in each region.

E.6 Under tactic B, generator A prices its high priced offer band just **above** the prices offered by generator B in region 2. Relevant notes include:

(a) the transmission system is exporting 19 MW; there is now 1 MW of unutilised transmission capacity and the system is not congested

(b) generator B is now the marginal generator in both regions

(c) price separation is reduced to zero because prices reflect generator B’s offer price

(d) however, generator A has had to forgo an additional 1 MW of generation to achieve this.

E.7 Next, all offer prices in the example above were multiplied by 100 in order to demonstrate the impact of the actual offer price. Relevant notes include:

(a) the quantities dispatched for each generator are identical to the case where the multiplier was not applied

(b) generator B is still marginal in both islands

(c) the price difference between the regions is still $0/MWh.

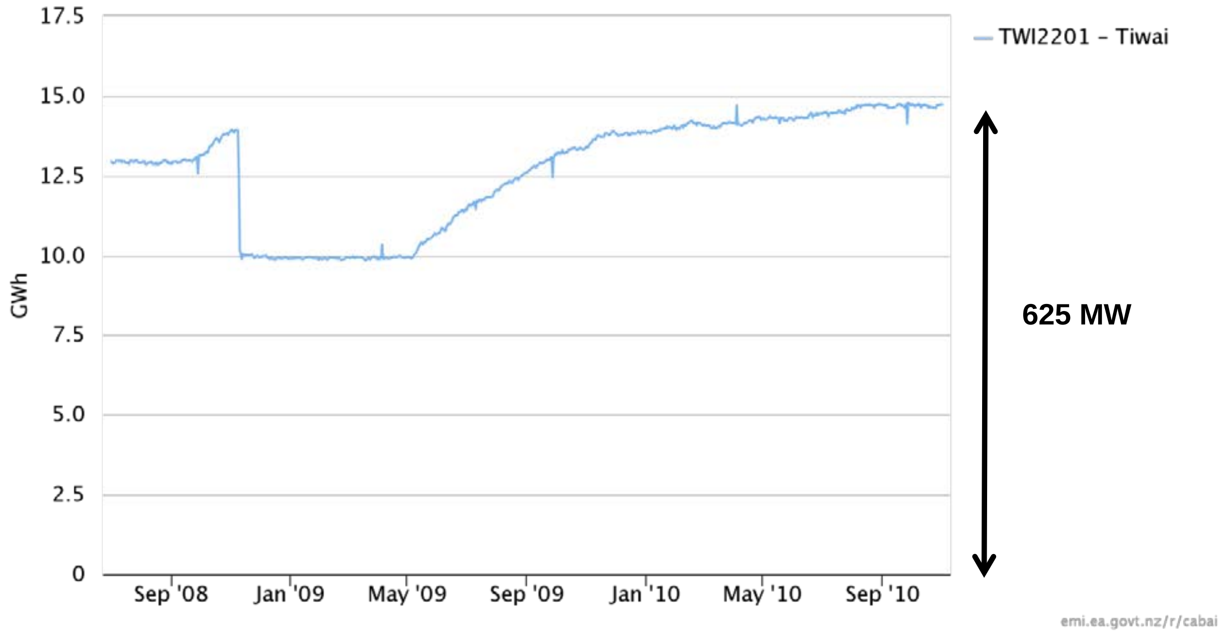
E.8 Under tactic B, region 1’s price **always** equals the price in region 2. The key insight here is the tactic that a net pivotal generator such as generator A might employ to manage their basis risk can be ‘in-play’ all the time. The environment dictates the impact of that tactic, as can be seen in the bottom two examples. Generator A’s tactic of keeping the transmission system just below its constraint limit produces prices in region 1 of $90/MWh or $9,000/MW ─ there is no change in tactic, just a change in the impacts.

E.9 As discussed in the example above, a generator’s actions can effectively set prices in a region without technically being the marginal price setter.

Case-study: 2008 Tiwai transformer failure

E.10 The Tiwai smelter had a transformer failure on 9 November 2008, reducing load by approximately 170 MW, as shown in Figure 30 below.

Figure 30: Tiwai smelter load 2008 - 2010



Source: Electricity Authority

E.11 This reduction in load over a summer period (when there is summer line ratings and high inflows) created a condition where the lower South Island region becomes an export constrained region.

E.12 The water spill report in Figure 31 is taken from Contact's website.[26] Contact defines relevant terms in the report as follows:

(a) COST: Hydro spill was due to the spot price not meeting the hydro generator's threshold for that plant 's short run cost for operating

(b) ECONOMIC: Hydro spill was due to economic reasons

(c) TRANSMISSION CONSTRAINT: Hydro spill was due to transmission or distribution constraints.

26 https://www.contact.co.nz/Assets/pdfs/corporate/environmental/Hydro_spill_Q4-08.pdf

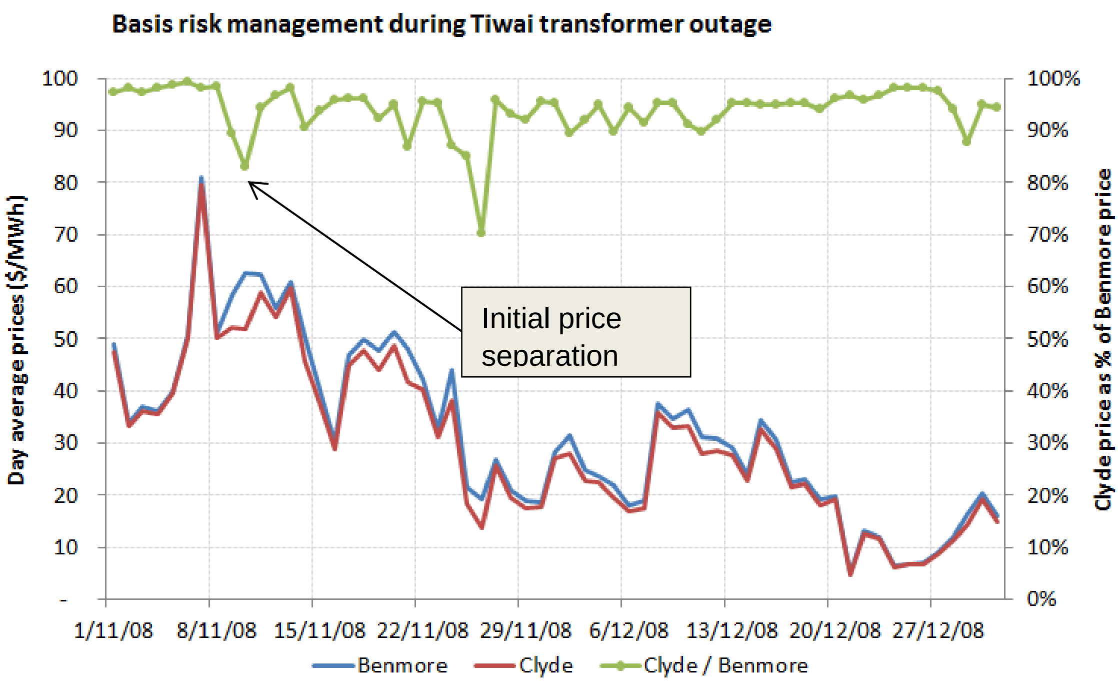
Figure 31: Contact Energy's hydro spill data for October-December 2008

TOTAL	*Values are expressed in gigwatt hours*												
Week ending	5-Oct-08	12-Oct-08	19-Oct-08	26-Oct-08	2-Nov-08	9-Nov-08	16-Nov-08	23-Nov-08	30-Nov-08	7-Dec-08	14-Dec-08	21-Dec-08	28-Dec-08
Plant	3.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	4.00	4.00	4.30	0.40
Obstruction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Inflow	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.60	0.00
Regulatory	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Contractural	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Recreational	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost	3.70	0.10	11.00	0.60	0.00	0.00	0.00	0.00	0.00	6.10	17.50	27.50	12.10
Economic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission Constraint	3.30	0.00	1.90	0.00	0.00	0.00	0.00	0.00	6.28	31.90	13.90	5.20	26.80
Hydraulic Constraint	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	10.70	0.10	12.90	0.60	0.00	0.00	0.00	0.00	7.68	42.00	35.40	37.60	39.30
Energy Produced	95.65	93.87	89.13	78.04	71.44	64.56	68.07	78.98	77.31	75.10	74.52	73.26	69.97
Spill/Inflows %	11.19%	0.11%	14.47%	0.77%	0.00%	0.00%	0.00%	0.00%	9.93%	55.92%	47.50%	51.32%	56.17%

Source: Contact Energy (see footnote for reference)

E.13 Over the last five weeks of 2008 Contact spilled 85 GWh as a result of transmission constraints (as highlighted by the red circle). This represented 23 per cent of their energy produced over this period.Figure 32 shows daily average prices at the Clyde and Benmore grid points (LHS axis) and the difference in price between Clyde and Benmore as a percentage (RHS axis). The Clyde hydro generator is owned by Contact and is located within the export constrained region, along with the Manapouri power station (owned by Meridian) as well as other smaller power stations. Benmore is located outside of the export constrained region; its data is representative of the general market price levels.

Figure 32: Basis risk management during the 2008 Tiwai transformer outage



Source: Electricity Authority

E.14 Prices within the constrained region (Clyde is used to illustrate general price levels within the constrained region) immediately decreased relative to Benmore after the transformer failure on 9 November 2008, before returning to close-to-normal relativity several weeks later; despite the amount of water being spilled over this period. Note that this example is not intended to conclude which party managed its offers to mitigate basis risk, only that offers were likely managed by one or more parties given the nature of the situation and the lack of price separation in the data.

E.15 This event highlights that basis-risk management through managing spot offers has been an active strategy for some time. The tactic of offering plant in such a way to keep prices in one region connected with prices on the rest of the grid is conceptually no different to the Meridian behaviour over the UTS claim period; albeit with quite different impacts.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
ASX	Australian Securities Exchange
Authority	Electricity Authority
BEN	Benmore
Code	Electricity Industry Participation Code 2010
FTR	Financial transmission right
IL	Interruptible load
IR	Instantaneous reserve
LHS	Left hand side
MW	Megawatt
MWh	Megawatt hour
NFR	Net free reserve
NISIR	North Island sustained instantaneous reserve
NRS	Non-responsive schedule
OTA	Otahuhu
POCP	Planned outage co-ordination process
PRS	Price responsive schedule
RHS	Right hand side
SIR	Sustained instantaneous reserve
SPD	Scheduling, pricing and dispatch
TCC	Taranaki Combined Cycle
TP	Trading period
UTS	Undesirable trading situation
vSPD	Vectorised scheduling, pricing and dispatch