Review of 26 September 2011 infeasibility situation

Market performance review

09 January 2012

Investigation stages

An in-depth investigation will typically be the final step of a sequence of escalating investigation stages. The investigations are targeted at gathering sufficient information to decide whether a Code amendment or market facilitation measure should be considered.

Market Performance Enquiry (Stage I): At the first stage, routine monitoring results in the identification of circumstances that require follow-up. This stage may entail the design of low-cost ad hoc analysis, using existing data and resources, to better characterise and understand what has been observed. The Authority would not usually announce it is carrying out this work.

This stage may result in no further action being taken if the enquiry is unlikely to have any implications for the competitive, reliable and efficient operation of the electricity industry. In this case, the Authority publishes its enquiry only if the matter is likely to be of interest to industry participants.

Market Performance Review (Stage II): A second stage of investigation occurs if there is insufficient information available to understand the issue and it could be significant for the competitive, reliable or efficient operation of the electricity industry. Relatively informal requests for information are made to relevant service providers and industry participants. There is typically a period of iterative information-gathering and analysis. The Authority would usually publish the results of these reviews but would not announce it is undertaking this work unless a high level of stakeholder or media interest was evident.

Market Performance Formal Investigation (Stage III): The Authority may exercise statutory information-gathering powers under section 46 of the Act to acquire the information it needs to fully investigate an issue. The Authority would generally announce early in the process that it is undertaking the investigation and indicate when it expects to complete the work. Draft reports will go to the Board of the Authority for publication approval.

The outcome of any of the three stages of investigation can be either a recommendation for a Code amendment, provision of information to a Code amendment process already underway, a brief report provided to industry as a market facilitation measure, or a no further action.

From the point of view of participants, repeated information requests are generally concerned with Stage II; trying to understand the issue to such an extent that a decision can be made about materiality.

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Executive summary

The pricing solve for 26 September 2011 had a deficit generation infeasibility situation[1] in trading period (TP) 16. On 26 September 2011, there was also a metering situation which was subsequently resolved. Following the resolution of the metering situation, there remained a deficit generation infeasibility at the Waipawa GXP (WPW0331) due to a binding transmission security constraint between Bunnythorpe and Woodville. The system operator resolved the infeasibility situation by adjusting the binding transmission constraint limits between Bunnythorpe and Woodville.

The resulting pricing solve still had a binding transmission security constraint between Bunnythorpe and Woodville, with the maximum and minimum prices in the North Island at Waipawa (WPW0331) and Mangahao (MHO0331) at $56,057 per MWh and -$3,716 per MWh respectively. This triggered a high spring washer (HSW) price situation which resulted in the application of the HSW price relaxation factor. This reduced the price at WPW0331 to $3,204 per MWh and the MHO0331 price changed to $0 per MWh.

The Electricity Authority (Authority) queried the revised limits applied by the system operator in resolving the infeasibility situation. The Authority was subsequently informed by the system operator that an error was made in resolving the infeasibility situation, which resulted in an over-relaxation of a transmission security constraint limit. The system operator lodged a self-reported breach on 23 November 2011 with regards to the error made in resolving the infeasibility. The breach notification is being processed in accordance with the Compliance process.

This review indicates that the major contributing factor to this infeasibility situation was the HVDC being constrained to zero in final pricing. This issue was the subject of a previous review[2] by the Authority which proposed a solution to remove these constraints from final pricing when the link is in service. This review of 26 September 2011 infeasibility pricing situation, indicates that had this change been in place, the resulting infeasibility would not have occurred, and final prices would have better represented the average real-time prices observed during the affected trading period.

The analysis in this review of the 26 September 2011 infeasibility pricing situation, also indicates that had the errors in the infeasibility resolution process not been made, prices in excess of $55,000 per MWh[3] could have occurred in the lower North Island due to a binding transmission constraint between Bunnythorpe and Woodville. The HSW price situation methodology in place at that time would have been ineffective in significantly reducing these prices. This is due to the presence of multiple branch security constraints generated by the system operator's automatic constraint builder (SFT) implemented in March 2011. This potential ineffectiveness of the previous HSW process with SFT was the subject of another review[4] by the Authority.

The HSW price situation methodology was subsequently amended in December 2011 under an urgent rule change. This amendment restored the HSW effectiveness by allowing for the relaxation of multiple parallel transmission security constraints. This amendment would have resolved the extreme prices in this instance. This urgent amendment is an interim solution until

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[1] Infeasibility situation means a situation where the software used to determine final prices and final reserve prices calculates a model variable with a value (either positive or negative) as set out in the list given to the pricing manager under Schedule 13.2. This list in Schedule 13.2 includes deficit bus generation amongst others.

[2] See Review of price separation during HVDC reversal which is available at http://www.ea.govt.nz/industry/monitoring/reports-publications/investigations-by-year/investigations-2011/.

[3] The maximum energy offer price during this time was $5,000/MWh.

[4] See Review of High Spring Washer Resolution Issue with SFT which is available at http://www.ea.govt.nz/industry/monitoring/reports-publications/investigations-by-year/investigations-2011/.

the proposed changes outlined in the Authority's previous review[4] can be implemented via another Code amendment process, following the normal Code amendment process.

A similar situation to the event of 26 September occurred on 14 August 2011 during TP 35. The Authority believes that these situations provide an early warning of the potential for extreme prices in the market with an increased risk of this occurring until the proposed changes to the treatment of the HVDC constraint and further changes to the high spring washer process are implemented[5].

Furthermore, the Authority believes that a generalised treatment of potential extreme prices should be catered for within the HSW price situation methodology. Currently the price amplification effects due to binding transmission security constraints are considered. However these amplifications can also occur due to other constraints, such as those relating to energy and reserves. A generalised treatment would allow other constraints to be relaxed to reduce the potential for price amplification effects when they reflect mathematical peculiarities rather than economic effects. The HSW price effects are currently on the Locational Price Risk Technical Group (LPRTG) terms of reference. These HSW price effects and the potential discontinuities between the pricing and dispatch process were raised at their meeting on 23 November 2011. The LPRTG agreed that this was an issue to consider and would include this within their work plan. The Authority is developing a paper outlining these issues which will be presented to its Board in early 2012.

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[5] The details of these issues and the proposed changes are contained in the Authority's "Review of price separation during HVDC reversal" and "Review of High Spring Washer Resolution Issue with SFT". These are available at http://www.ea.govt.nz/industry/monitoring/reports-publications/investigations-by-year/investigations-2011/.].

1   Introduction

1.1   The final pricing solve for 26 September 2011 had an infeasibility situation in TP 16. This was due to a significant binding transmission security constraint between Bunnythorpe and Woodville, resulting in a deficit generation infeasibility situation at WPW0331.

1.2   A metering situation notice was also published for 26 September 2011.

1.3   A revised final pricing case was provided to the Authority by the pricing manager on 27 September 2011. This revised pricing case had the infeasibility situation resolved by increasing the branch limits on two transmission security constraints between Bunnythorpe and Woodville by different amounts. The original constraints and revised limits applied to the pricing case are listed in Table 1 below.

Table 1   Affected transmission security constraints for 26 September 2011 (TP 16)

Constraint name	Equation	Limit	Revised limit
BPE_WDV1.1_BPE_WDV2.1__BPE_WDV2__BPE__LN	1.051*BPE_WDV1.1 + 0.853*BPE_WDV2.1	75.03	77
BPE_WDV2.1_BPE_WDV1.1__BPE_WDV1__BPE__LN	1.051*BPE_WDV2.1 + 0.853*BPE_WDV1.1	75.03	76

Source: Pricing manager

Notes: 1.   Extracted from the final pricing case files

1.4   Under the Code[6], the system operator is required to exercise reasonable endeavours to resolve this provisional price situation.

1.5   The system operator publishes the procedure it uses to resolve infeasibilities[7]. This procedure indicates that the right-hand side limits of binding branch security constraints can be changed to resolve a deficit bus generation infeasibility. Any change made is the smallest integer value necessary to remove the infeasibility.

1.6   Following the resolution of the infeasibility, the transmission security constraint between Bunnythorpe and Woodville (BPE_WDV2.1_BPE_WDV1.1__BPE_WDV1_BPE__LN) was still binding with prices at WPW0331 reaching $56,057 per MWh[8]. This triggered a HSW price situation which invoked the HSW price situation methodology that applied at the time. This methodology involved relaxing the transmission security constraint with the highest constraint price by the greater of 1MW or 1%.

1.7   Applying the HSW price relaxation factor to the binding constraint reduced the WPW0331 price to $3,204/MWh and increased the MHO0331 price to $0/MWh as illustrated in Figure 1. These are the published final prices.

1.8   On 28 September 2011, the Authority queried the differences of the revised limits listed in Table 1 with the system operator. On 11 October 2011, the system operator indicated to the Authority that an error was made in resolving the infeasibility situation. This error resulted in one of the constraints listed in Table 1 being relaxed too far. The system operator had initially thought that
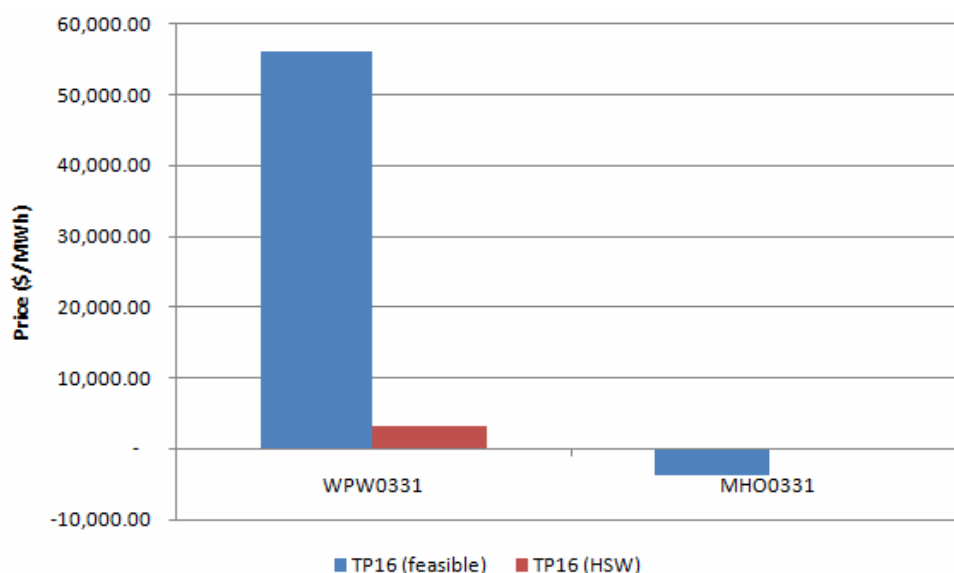
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[6]   See clause 13.146 (1) of the Code.

[7]   See http://www.systemoperator.co.nz/f2766,16927031/resolving-infeasibilites-and-constraints-jun-10.pdf.

[8]   The minimum price in the North Island was at MHO0331 (-$3,716 per MWh).

the source of this error was caused by using the input data prior to resolving the metering situation. Following an internal investigation, the system operator determined that this was not the case, and that an error was made in following the infeasibility resolution process. The system operator lodged a self-reported breach with the Authority on 23 November 2011.

Figure 1   North Island prices before and after the HSW resolution process
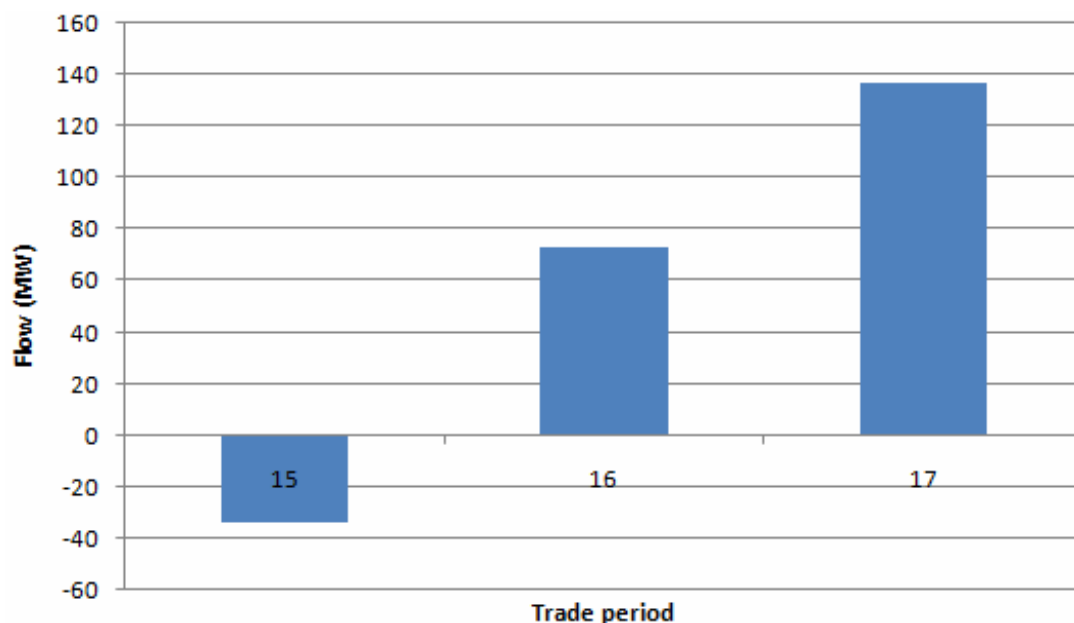

Source: Pricing manager

Notes: 1.   Feasible prices obtained from the revised final pricing case provided by the pricing manager

1.9   This review considers the issues surrounding the infeasibility and the potential prices and market impact which would have occurred had the error not been made. Changes to the infeasibility resolution process are proposed in this review to reduce the potential for a similar situation occurring in the future. Furthermore, there is some discussion in this review about the potential for extreme prices to exist in general, and proposals to address this issue.

2   Contributing issues to the infeasibility situation

2.1   There were several contributing issues to the infeasibility situation observed in TP 16 on the 26 September 2011. These included the low levels of intermittent generation in the lower North Island and the binding transmission security constraint on the Bunnythorpe and Woodville circuits. However, the constraining of the HVDC pole 2 flow to zero during this trading period was the major contributing factor to the difference between the observed real-time conditions and the resulting final pricing conditions.

2.2   Analysis of the SCADA data illustrates that between TP 15 and TP 16, the HVDC flow was changing direction, as indicated in Figure 2. When the HVDC changes direction and if the flow on the pole is scheduled below its minimum operating limit in real-time, the flow on a pole is constrained to zero in the dispatch schedule. If this constraint occurs across a trading period boundary, it is applied to final pricing. The system operator has indicated that this change has been implemented for HVDC pole 2 since the introduction of the upgraded market system in July 2009. The Authority is currently negotiating a Technical Advisory Services Contract (TASC) request with the system operator to develop a proposal for removing these constraints from the final pricing schedule.

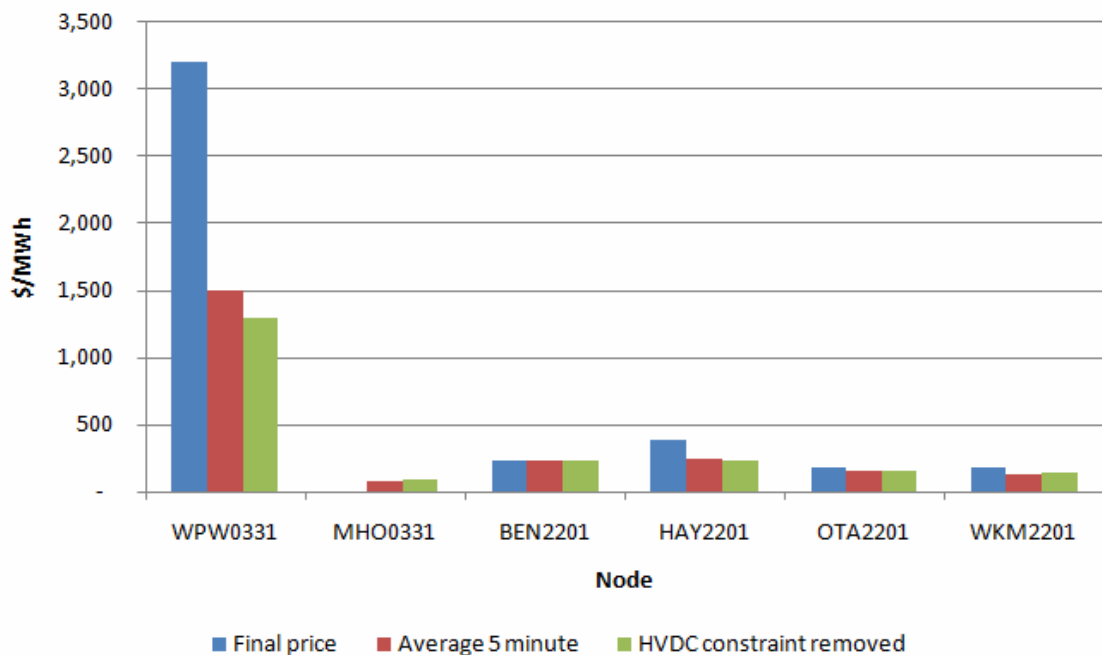**Figure 2   SCADA HVDC flow on 26 September 2011 (TP16)**

Source: EM6

Notes: 1.   Positive indicates flow from Benmore to Haywards
           2.   Negative indicates flow from Haywards to Benmore

2.3   The Market Performance's analysis of this event indicates that if this constraint on the HVDC pole 2 was not applied to final pricing, the resulting infeasibility and HSW price situation would not have occurred.

2.4   The simulated final prices at various locations, with this HVDC constraint removed, are illustrated in Figure 3. This indicates that these prices, with the HVDC pole 2 constraint removed, would more closely represent the average five minute prices observed by participants during real-time. This is because during real-time, the HVDC flow was not constrained to zero for the entire trading period, as represented in the final pricing solve.

Figure 3   Price comparison at selected nodes on the network

Source: Electricity Authority

2.5   Given the potential for the HVDC pole flow to be constrained to zero in final pricing prior to an implementation of a solution to remove these constraints, the underlying HSW price situation methodology needs to be robust enough to resolve any resulting HSW price situations. Failing this, the market could be exposed to potential extreme price spikes. This issue is discussed further in the next section.
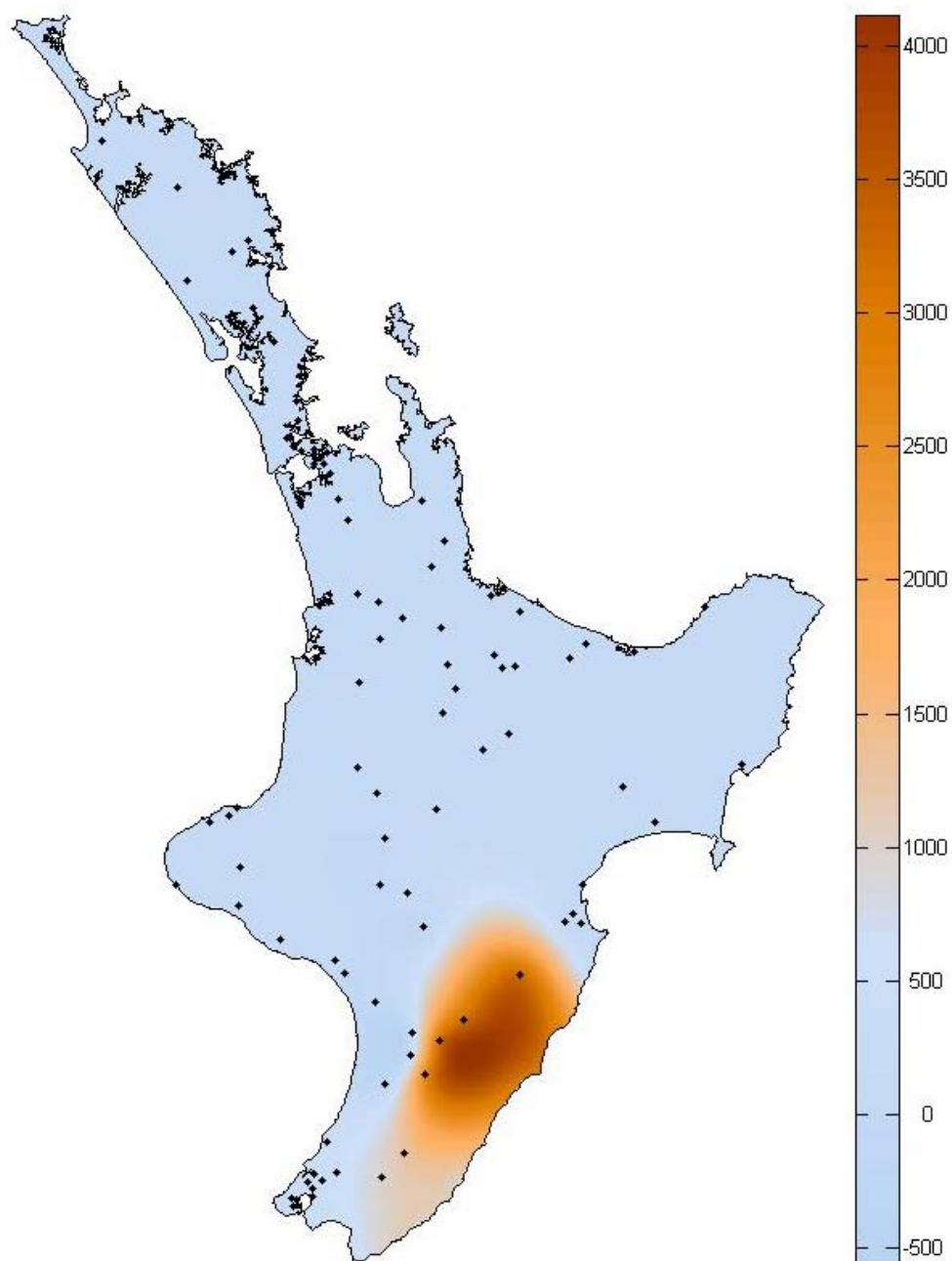
3   Potential extreme prices

3.1   The Authority has considered the potential prices that might have prevailed had the infeasibility situation been resolved correctly.

3.2   The Authority's analysis indicates that with both the transmission security constraint limits in Table 1 revised to 76MW, the infeasibility situation would have been resolved[9], but a HSW price situation would still have been triggered. The HSW price situation methodology which applied at the time, would not have reduced the extreme prices in the North Island. It is estimated that following the application of the HSW price relaxation factor, a maximum price in the North Island of $56,057 per MWh at Waipawa (WPW0331) and a minimum price of -$3,716 per MWh at Mangahao (MHO0331) would have resulted.

3.3   This ineffectiveness of the HSW price situation methodology, which applied at the time, was due to the similarity of the transmission security constraints generated by SFT. Relaxing the binding security constraint results in the other similar constraint binding shortly thereafter, thus not allowing much reduction in the HSW prices.

3.4   This significantly impacts the prices in the North Island as illustrated in Figure 4 and Figure 5. Figure 4 provides an indication of the nodal final price distribution in the North Island for TP 16 on

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[9]   This has been confirmed by the system operator.

26 September 2011. Figure 5 indicates the simulated prices that could have been produced following the HSW price situation methodology, had the infeasibility situation been resolved correctly.

3.5   These simulated extreme prices in the North Island would have resulted in a significant impact on the market. It is estimated that an additional $2.58 million would have been paid by purchasers and an additional $138,000 would have been received by generators, with $72,000 of the generator payments being received via increased constrained on payments. It is estimated that the loss and constraint excess (LCE) for this trading period would have increased by $2.52 million.

Figure 4   Final prices for TP 16 on 26 September 2011
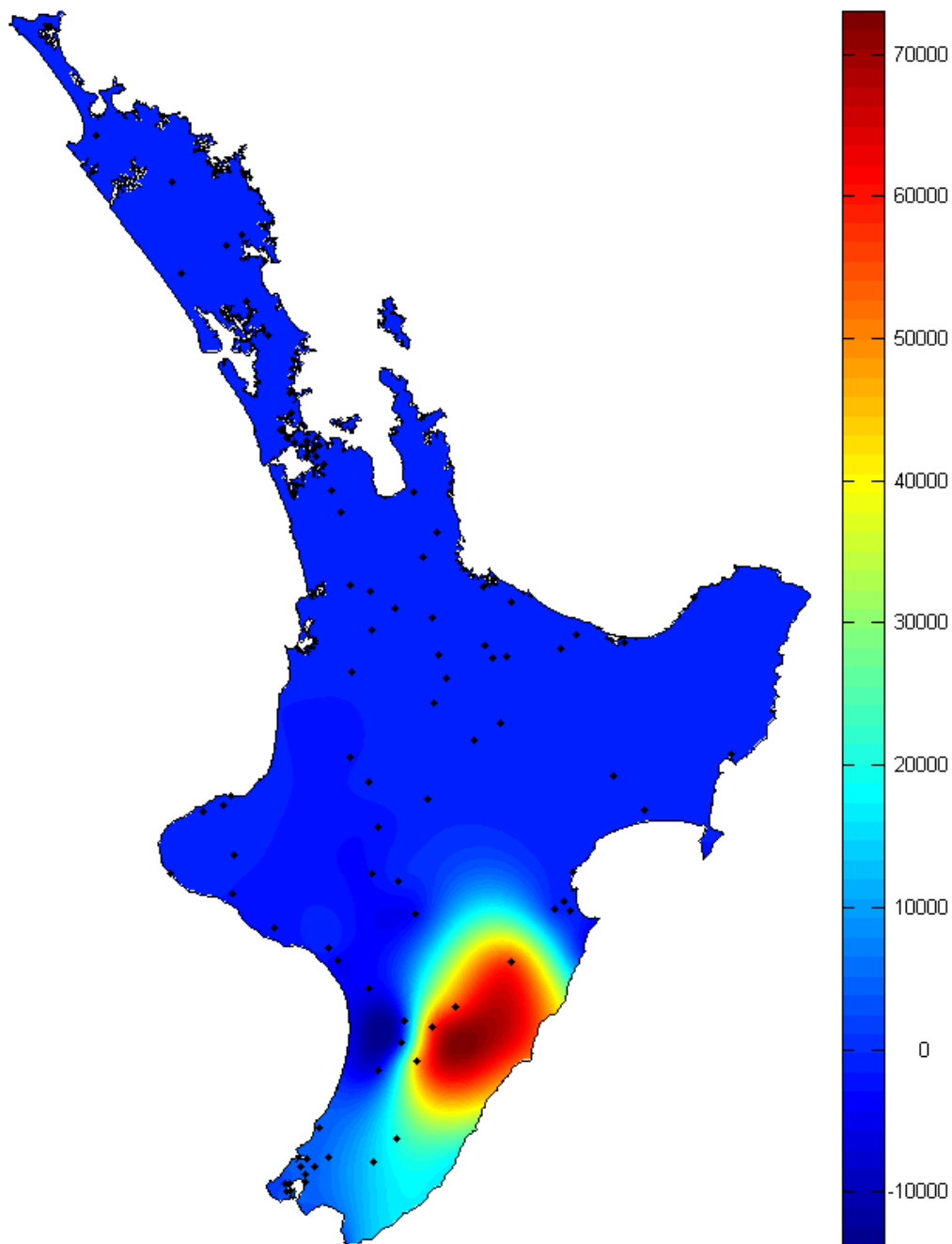

Source: Electricity Authority

Notes: 1. Prices are in dollars per MWh
              2. The maximum price is at Waipawa (WPW0331) at $3,204 per MWh and the minimum price is
                  at Mangahao (MHO0331) at $0 per MWh

Figure 5   Simulated final prices using corrected limits for TP 16 on 26 September 2011

Source: Electricity Authority

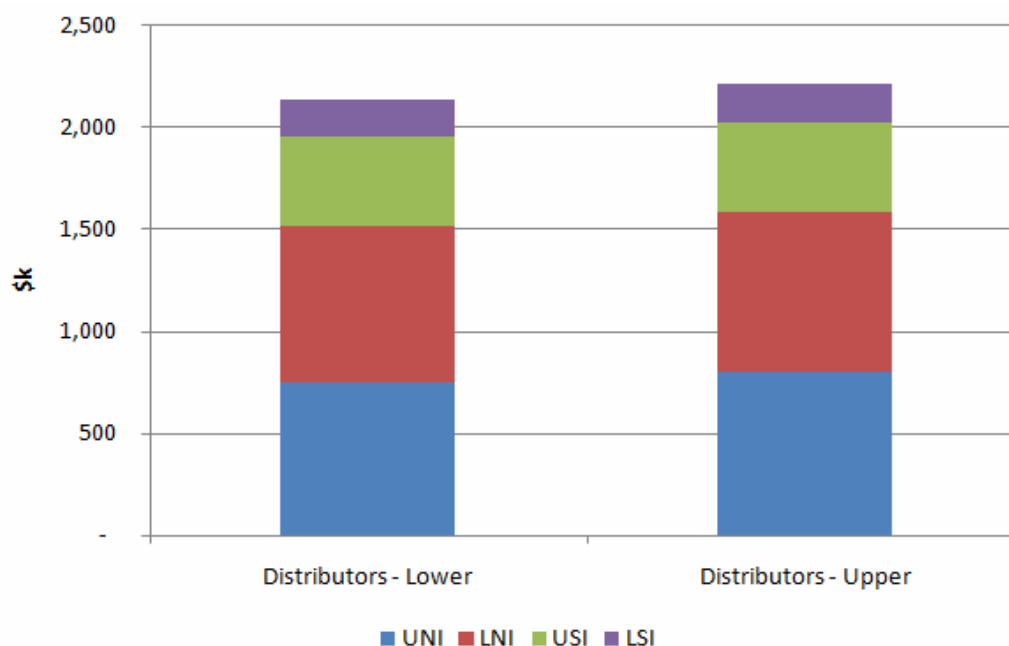Notes: 1. Prices are in dollars per MWh
            2. The maximum price is at Waipawa (WPW0331) at $56,057 per MWh and the minimum price
                is at Mangahao (MHO0331) at -$3,716 per MWh

3.6   The large increase in the LCE would have been due to the binding transmission constraint in the
       North Island (between Bunnythorpe and Woodville) which causes significant price separation
       within the island.

3.7   Currently, the LCE is allocated back to designated transmission customers (DSC) in proportion to
       their contribution to the transmission charges. The estimated allocation of this additional surplus

is illustrated in Figure 6 and Figure 7. Given that the HVDC arc flows in the dispatch[10] and final pricing schedules were zero during this time, the entire LCE is assumed to be attributed to the AC network.

3.8   There is some uncertainty around the allocation of the transmission charges and the nature of the eventual recipients of these LCE allocations at some direct connection locations. To reflect this uncertainty an "upper" and "lower" range of the potential allocation is indicated in Figure 6 and Figure 7.

Figure 6   Estimated allocation of additional LCE to distributors
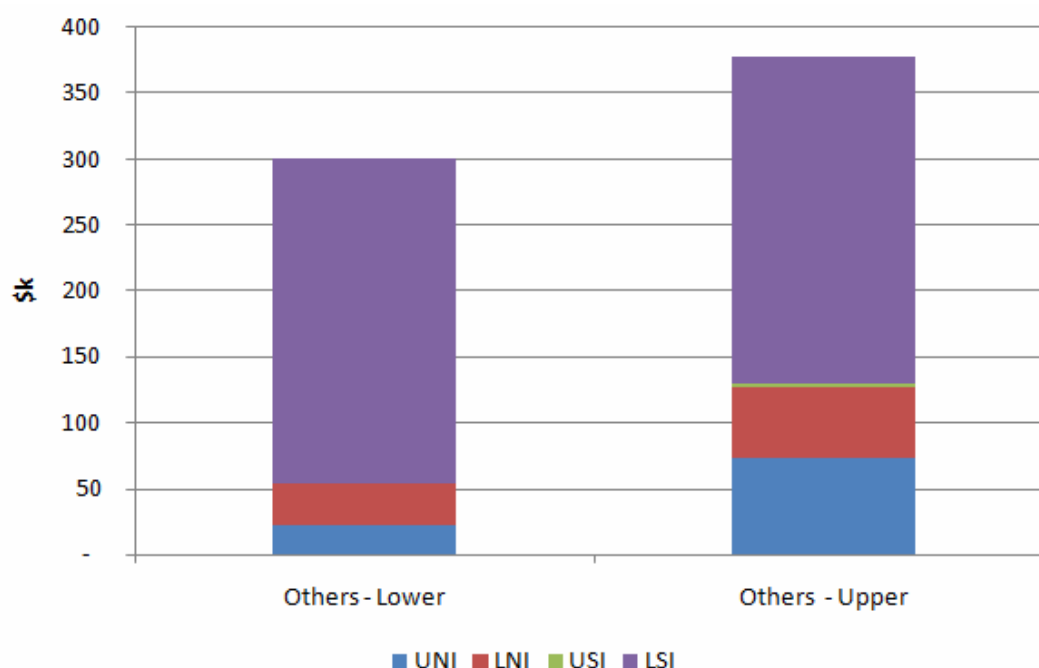

Source: Electricity Authority

Notes: 1. UNI, LNI, USI and LSI indicate the upper North Island, lower North Island, upper South Island and lower South Island regions respectively.
2. Upper and lower estimates are based on assumed upper and lower estimates of transmission charges.

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10   Note the dispatch schedule is also called the SDPQ schedule.

Figure 7   Estimated allocation of additional LCE to other DSCs

Source: Electricity Authority

Notes: 1. Others include direct consumers and generators
            2. The large LCE allocation in the LSI is due to the large direct consumer at Tiwai.
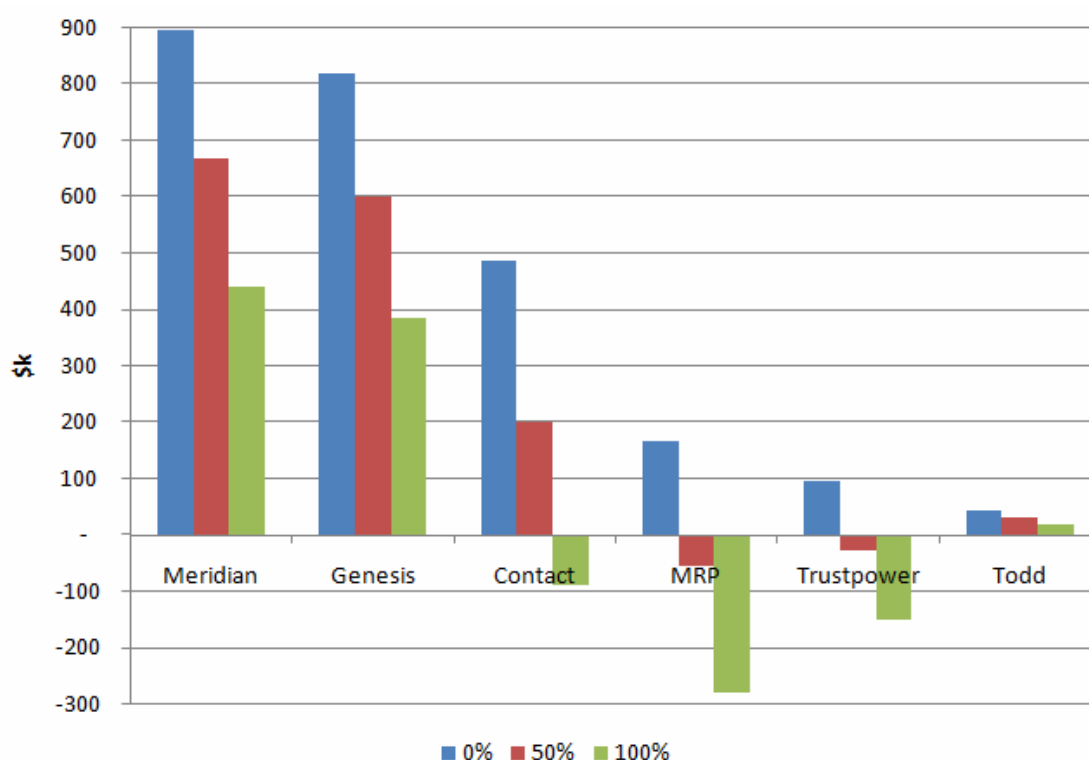
3.9   The above allocation estimates indicate that distributors would have been the major recipients (over 80%) of this additional LCE generated by the constraint. However, it should be noted that some of these distributors pass on the LCE to retailers on their networks, in varying degrees.

3.10   An estimated net[11] impact of the extreme prices on the major generator-retailers is shown in Figure 8. This constitutes over 99% of the net impact on the market participants.

3.11   To cater for the variation in the manner in which distributors pass back the LCE to retailers on their networks, a range of net impacts are illustrated assuming 0, 50 and 100 percent pass-through of the LCE from the distributor to the retailers[12].

3.12   As can be observed, the potential impact of these simulated extreme prices on market participants is large, although this is somewhat tempered by the potential LCE revenue that the retailers might receive from their respective distributors[13]. Furthermore, this analysis does not consider any hedge agreements participants might have at the different locations.

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[11]   This is the change in impact using the current final prices versus the simulated extreme final prices.

[12]   This allocation to the respective retailers is assumed to be in proportion to the retail load on the distributor's network.

[13]   The impact of this change on Meridian Energy assumes that they do not receive any LCE attributed to the lower South Island direct connect consumers.

Figure 8   Estimated net impact on generator-retailers for 26 September 2011, TP16

Source: Electricity Authority

Notes: 1. This includes changes in purchaser, generation and constrained-on payments.
2. Positive indicates a net loss from this change.
3. The calculations for Meridian assume no revenue from the LCE allocated to the LSI direct consumers.

3.13   The observation of this HSW effect in both the 14 August 2011 and 26 September 2011 events, provides an early warning of this potential extreme price risk. The Authority therefore believes that, if approved, the proposed changes to the Code recommended in the two previous reviews published in December 2011[14], around the HSW methodology and the proposed changes to the pricing model constraints surrounding the HVDC, will be vital in reducing the potential for this risk.

3.14   In the interim, to restore the effectiveness of the HSW price situation methodology, from before the introduction of SFT, an urgent amendment to the Code was implemented in December 2011. This amendment allows for the application of the HSW price relaxation factor to parallel transmission security constraints. This is aimed at addressing the multiple transmission security constraints produced by SFT. If the amendments had been in effect in this instance, the extreme prices in the lower North Island would have been reduced.

3.15   The Authority also believes that the current HSW price situation definition does not cater for potential extreme prices which could occur as a result of other price amplification mechanisms, other than transmission security constraints. Such effects could occur when the system is

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[14]   As mentioned earlier, the details of these issues and the proposed changes are contained in the Authority's "Review of price separation during HVDC reversal" and "Review of High Spring Washer Resolution Issue with SFT". These are available at http://www.ea.govt.nz/industry/monitoring/reports-publications/investigations-by-year/investigations-2011/.].

capacity constrained[15]. This can result in energy and reserve prices well above market offer prices, which are also very sensitive to the pricing model input parameters.

3.16   The Authority's analysis indicates that prices more than 40 times above the highest offer price could have transpired in some "near miss" instances[16]. While these prices are in theory the marginal costs of supplying electricity at that geographic location at that time, and are consistent with the minimum cost dispatch, the current pricing process in the wholesale electricity market can result in deviations between the ex-post final prices, at which participants settle, and the price information provided to participants before and during real-time[17].

3.17   These deviations can affect the ability of participants to predict and respond to these extreme prices, thus reducing their positive economic signalling impact whilst still exposing participants to significant price risk. The amended HSW price methodology was in part introduced to address this, given the extreme sensitivity of prices to the input parameters in these constrained situations.

3.18   Since the amended HSW price methodology is specific to transmission security constraints, a generalisation of this definition would be needed to address the generalised issue of constraint relaxation to reduce the likelihood of extreme price amplification and potential market risk due to other mechanisms.

4   Action taken

4.1   The system operator has lodged a self-reported breach with the Authority on 23 November 2011 with regards to the error made in resolving the infeasibility. This error relates to the over relaxation of the constraint in the infeasibility resolution process. The breach notification is being processed in accordance with the Compliance process.

4.2   The Authority is negotiating a TASC request with the system operator on options to remove the application of the HVDC constraint from final pricing when the HVDC pole is available. The removal of the HVDC constraint would have alleviated the above issue.

4.3   The Authority is progressing with a proposed Code amendment to the HSW resolution process. If approved, the proposed Code amendment would increase the effectiveness of this resolution process when prices rise well above market offers due to binding transmission constraints. If approved, the amendment is expected to be implemented by June 2012.

4.4   As an interim solution, the Authority passed an urgent Code amendment in December 2011 to restore the effectiveness of the HSW price situation methodology[18] in the post-SFT market.

4.5   In addition, at a meeting held with the system operator on 30 September 2011, the Authority proposed a change to the system operator's current infeasibility resolution mechanism. The proposed change considered the removal of the constraint restricting the HVDC flow to zero when it is in service and changing direction. The system operator has subsequently indicated that while in these instances the HVDC constraint was the cause, in other instances it might not be, and such proposed change could mask other infeasibility issues. The Authority does not agree

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[15]   The market clearing engine (SPD) incurs significant incremental costs, by rebalancing resources, in meeting the marginal system energy and reserve requirements. This results in these extreme prices.

[16]   In theory prices in the range of the constraint violation penalties (CVP) used in SPD are possible. These are in excess of $100,000/MWh. These CVP values have no economic basis and are used to identify sources of potential infeasibility.

[17]   The 26 September 2011 scenario is one example of this.

[18]   The details of the amendment can be found at http://www.ea.govt.nz/act-code-regs/code-regs/code-changes/2011/.

with this assessment. The Authority considers that the proposed change is a prudent and reasonable option considering the potential discontinuity this HVDC constraint introduces between real-time and final prices.

4.6   The impact of HSW prices, and in general extreme prices, and their effects was raised at the LPRTG meeting on 23 November 2011. Potential resolution mechanisms were also presented to the group by Authority staff. These mechanisms are primarily aimed at addressing the generalised extreme price risk in the market and improving alignment between the dispatch and pricing process in the market. These issues included:

(a)   aligning the treatment of intermittent generation in the pricing process with the real-time process;

(b)   extending the softening of constraints to address the generalised extreme price issue; and

(c)   introducing 5 minute final prices to improve alignment between dispatch and pricing.

4.7   The LPRTG agreed that the impact of HSW prices was an issue and would include this within its work plan.

4.8   The Authority is developing a paper setting out these issues which is expected to be presented to its Board in early 2012.

Glossary of abbreviations and terms

Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
CVP	Constraint violation penalty
DSC	Designated transmission customers
GXP	Grid exit point
HSW	High spring washer
LCE	Loss and constraint excess
LPRTG	Locational price risk technical group
MHO0331	Maugahao GXP
MW	Megawatt
MWh	Megawatt hour
RTD	Real-time dispatch
SCADA	Supervisory Control and Data Acquisition
SO	System Operator
SPD	Scheduling, Pricing and Dispatch
TASC	Technical Advisory Services Contract
TP	Trading period
vSPD	Vectorised Scheduling, Pricing and Dispatch
WPW0331	Waipawa GXP