Security and Reliability Council

Winter 2014 grid emergencies

The Electricity Authority's review of the 27 May and 19 August 2014 grid emergencies

11 March 2015

Note: This paper has been prepared for the purpose of the Security and Reliability Council (SRC). Content should not be interpreted as representing the views or policy of the Electricity Authority.

Background

The Security and Reliability Council's (SRC) functions under the Electricity Industry Act 2010 include providing advice to the Electricity Authority (Authority) on reliability of supply. The SRC has determined that part of its role with respect to reliability is to be selectively involved in post-event reviews so as to ensure lessons are learned from events (or near-misses), particularly where those lessons involve cross-industry coordination.

The SRC, during its June and October 2014 meetings, expressed an interest in the power system events that occurred on 27 May 2014 and 19 August 2014. The Authority conducted an enquiry that covered both of these events in a single report. That report was published 9 December 2014 and is attached to this cover paper.

The purpose of this paper is to present the Authority's report on the 2014 grid emergencies and seek the SRC's advice to the Authority Board.

The SRC may wish to consider the following questions.

Q1.	Does the SRC agree that the Authority's report on the winter 2014 grid emergencies has accurately established the key facts relating to the events?
Q2.	Does the SRC agree with the conclusions that the Authority drew from the facts relating to the events?
Q3.	What advice, if any, does the SRC wish to provide to the Authority?

2014 Winter Grid Emergencies

Market Performance Enquiry

9 Decemebr 2014

Version control

Version	Date amended	Comments
2	25/11/2014	Includes feedback from system operator

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 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.

Executive summary

1.1 The Electricity Authority has undertaken a market performance enquiry following two recent grid emergency events on the 27 May and 19 August, 2014. In both cases there were no concerning trading conduct and the high prices reflected the prevailing market conditions.

1.2 However, the enquiry has highlighted:

- (a) transmission charging impacts that undermine grid security, in particular actions taken by generators and industrial demand in response to transmission pricing incentives
- (b) low and inaccurate forecast spot prices resulting in little incentive for participants to react to developing grid emergency situations.

1.3 These could be improved if:

- (a) The TPM was amended to create different incentives for participants, for example by:
  - (i) moving away from the current HAMI-based HVDC charge to either an capacity charge or MWh charge
  - (ii) improving incentives for interruptible load providers to remain connected through peak periods.
- (b) Demand-side participation and thermal generation commitment were improved. Both of these provide greater wholesale participation and price certainty. Options for achieving this could be:
  - (i) through an ex-ante final price, currently being investigated by the Authority
  - (ii) other possible avenues to help forecasting, and therefore price certainty, such as improvements to the System Operator’s demand forecasting methods or the possibility of a pre dispatch sensitivity schedule and wind forecasting.

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2 Background

2.1 The Authority has conducted an enquiry into the performance of the market following grid emergencies on 27 May 2014 and 19 August 2014. The Authority's statutory objective is to:

To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

2.2 The Authority has interpreted reliable supply as:

Exercising its functions in ways that 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.

2.3 The grid emergencies that are the subject of this enquiry are examples of times when grid security was fragile. Consequently, this enquiry takes as it starting point the reliability arm of the statutory objective.

The 27 May Grid Emergency

2.4 A cold southerly front across New Zealand on the morning of 27 May 2014 caused peak demand to increase by over 500MW, a 15% increase in demand compared with the previous day. This was a large increase between business days, which although unusual, can occur a few times per year.

2.5 Demand was under-forecast. Standby Residual Check (SRC) notices were not issued by the System Operator until 5:36am. These notices are the first sign of a potential capacity shortfall situation developing. By 7:31am, the System Operator issued a nationwide grid emergency due to insufficient generation offers. The Grid Emergency Notice was issued for the period between 7:30am to 9:30am (Trading Periods 16-19).

2.6 Real time prices during TP16 reached $100,000/MWh indicating insufficient reserve offers. In final pricing, TP16 reached $1,000/MWh across New Zealand with Ohau A the marginal generator setting the price at $975/MWh.

2.7 Pre-dispatch prices for this period remained low indicating nothing of significance for any of the trading periods except TP16 where pre-dispatch prices reached around $260/MWh and over $400/MWh just prior to TP16.

2.8 Many factors contributed to this grid emergency.

(a) Small pre-dispatch demand forecast inaccuracies causing large pre-dispatch price forecast inaccuracies[1].

(b) A lack of reserve offers in the North Island.

(c) A lack of nationwide energy offers.

(d) A drop in wind generation nationwide.

[1] Transpower have recently trialled other demand forecasting methodologies/providers. Several of the trialled forecast providers improved on the status quo. An upgrade to the load forecasting model was planned for the 2014-15 financial year but has recently been postponed.

2.9 vSPD experiments show that increasing North Island interruptible load by 10MW or increasing South Island generation offers by 80MW reveals final prices much closer to those seen in the pre-dispatch schedules (~$400/MWh).

2.10 Bona fide generation outages included a within-gate-closure tripping of an Ohakuri unit (28MW), and bona fide changes to South Island energy offers at the Ohau B and C sister stations (80MW at 4:30am, ~1 hour prior to gate closure). Although not major outages, these exacerbated the grid emergency situation and meant that pre-dispatch prices didn't reflect the supply situation before these bona fide changes were taken into account.

The 19 August Grid Emergency

2.11 The 19 August grid emergency situation developed during the evening peak period. SRC notices had been issued by the System Operator, starting during the morning of the previous day, 18 August. By 14:56pm on the 19 August, the SO issued a warning notice for insufficient generation offers between 17:30 and 19:30 (trading periods 35-40). At 17:54pm this was upgraded to a full Grid Emergency Notice, calling for additional generation offers between 17:50 and 19:30 (TP 35-40).

2.12 Table 1 contains pre-dispatch and final prices as at 3pm on 19 August 2014[2]:

Table 1: pre-dispatch and final prices at 3pm 19 August 2014

TP	Pre-dispatch NRS@3pm	Pre-dispatch PRS@3pm	Settlement prices
TP35	<$100	<$100	$5400
TP36	<$100	<$100	$2400
TP37	~$645	~$500	$9700
TP38	~$645	~$500	$500
TP39	~$300	~$130	$400
TP40	<$100	<$100	$130

2.13 The System Operator released a comprehensive technical report on the 19 August grid emergency.

https://www.systemoperator.co.nz/sites/default/files/bulk-upload/documents/20140819%20Reserve%20Deficit%20Report%20Final.pdf

2.14 The report focused on trading period 37. In that trading period the pricing manager created a virtual reserve provider under clause 13.166A of the Electricity Industry Participation Code (Code) and set the reserve price in the North Island to $9000/MWh (three times the highest NI energy offer).

2 Prices at Otahuhu.

2.15 The System Operator concluded:

Operationally, the electricity market performed as expected given the load and generation offers. Although the electricity price spiked relatively high for the 18:00 trading period, no single parameter had a defining effect on the situation. A combination of a lack of generation offers, natural variation in load forecasting and wind generation and demand-side participation resulted in a shortfall of energy and reserve offers to meet the required load and reserve requirement. The result of this situation was high prices, as would be expected.

2.16 Again, many factors were involved and it is difficult to point a finger at any one cause. During the emergency, South Island generators[3] responded, releasing additional generation. The Authority understands that Transpower decided under clause 34 of the TPM not to take into account the peak generation in calculating those generators' HVDC charges[4].

Common themes for the grid emergencies

2.17 Both grid emergencies share some common themes.

(a) Periods of low prices leading to the withdrawal of offers for large thermal plant.

(b) Incentives created by the TPM leading to a lack of offers during peak demand periods, increasing the risk of a security issue arising.

(c) Pre dispatch quantities and prices not adequately warning the market of the extent of the shortfalls.

Other background: recent changes to the electricity market

2.18 Other recent changes have affected the electricity market.

(a) A substantial increase in transmission charges over recent years.

(b) Large South Island hydro plant on prolonged maintenance over winter 2014.

(c) An increase in HVDC capacity.

(d) Baseload North Island geothermal generation on the increase.

(e) Retirement of large North Island thermal plant.

(f) Wetter than average hydrological conditions pushing energy prices lower over winter 2014.

(g) Lower prices resulting in CCGT North Island thermal generators becoming less economic and consequently not being offered and being unable to respond to high prices because of their warm up times.

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3 At 5:56pm, four minutes prior to 6pm (TP37), Meridian Energy offered an additional 60MW at Benmore for Trading periods 37, 38 and 39. At 6:07pm, Contact Energy had offered an additional 104MW from Roxburgh and Clyde for Trading Periods 38 and 39.

4 Under Schedule 12.4 clause 34 of the Code, Transpower may make adjustments to the calculation of a customer's transmission charges if Transpower considers that there has been an exceptional operating circumstance.

(h) National peak demand that has been reducing (since 2007).

2.19 These changes, for the most part, have resulted in an increasing proportion of supply from renewable generation across the country, resulting in lower energy prices (2014 looks likely to exceed 80% of generation coming from renewable sources). Offsetting this are correspondingly higher transmission charges. A consequence appears to be a market in which peak demand periods have become increasingly tight with less generation being offered to the market.

2.20 This paper uses the term pre-dispatch price to refer to the price responsive and non-price responsive price schedules that are published by NZX. These prices are forecast every 2 hours 36 hours in advance of the trading period. Four hours from the trading period the prices are forecast every half hour. The price responsive schedule includes the effect of load switching off in response to high prices.

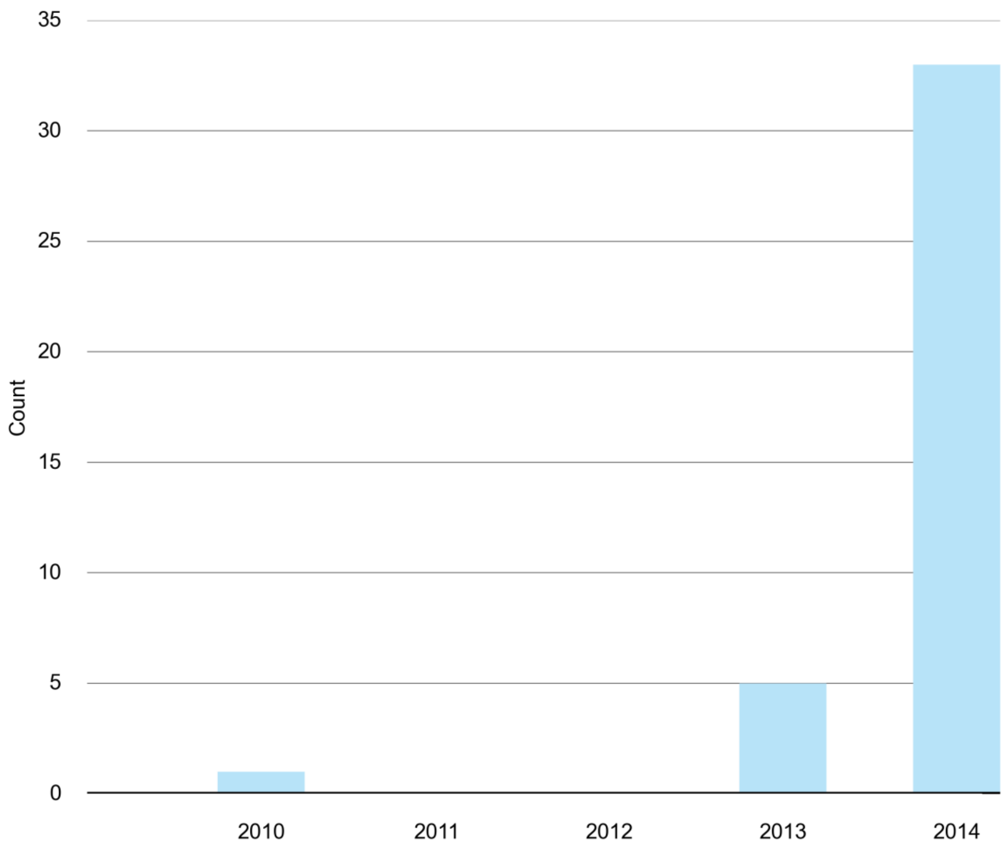
3 Increasingly tight supply conditions

3.1 When supply becomes tight, a small change in demand can potentially have a large impact on energy price. To demonstrate this, Figure 1 illustrates the results of an experimental vSPD pricing run. In this experiment the market is resolved for every trading period since 2010 with a small 2.5% increase in demand.

3.2 The bar chart illustrates the annual number of trading periods where a 2.5% increase in demand causes price increases of more than $1,000/MWh over the historical final price.

3.3 As with all experiments that simulate something that never happened, this analysis assumes nothing changes in the market as a result of the perturbation. With the small perturbation we are using here we think we can justify this assumption, but we also expect that the size of the price increases that this experiment causes would stimulate offers which would in turn reduce the price.

Figure 1 Count of energy prices exceeding $1000/MWh after an experimental increase in national demand of 2.5% for every trading period.



3.4 That a small increase in demand has such an impact on energy price indicates tight supply conditions and an offer curve very sensitive to small changes in demand during peak periods. This has an impact on the ability to accurately forecast prices, creating uncertainty for participants as to how they should react. This is discussed further below.

Pre dispatch pricing accuracy

3.5 Both grid emergency events have highlighted inaccurate low pre-dispatch prices during the lead up to the grid emergency periods. Low pre-dispatch prices give no warning of an upcoming shortage and give participants less time to respond to the grid emergency.

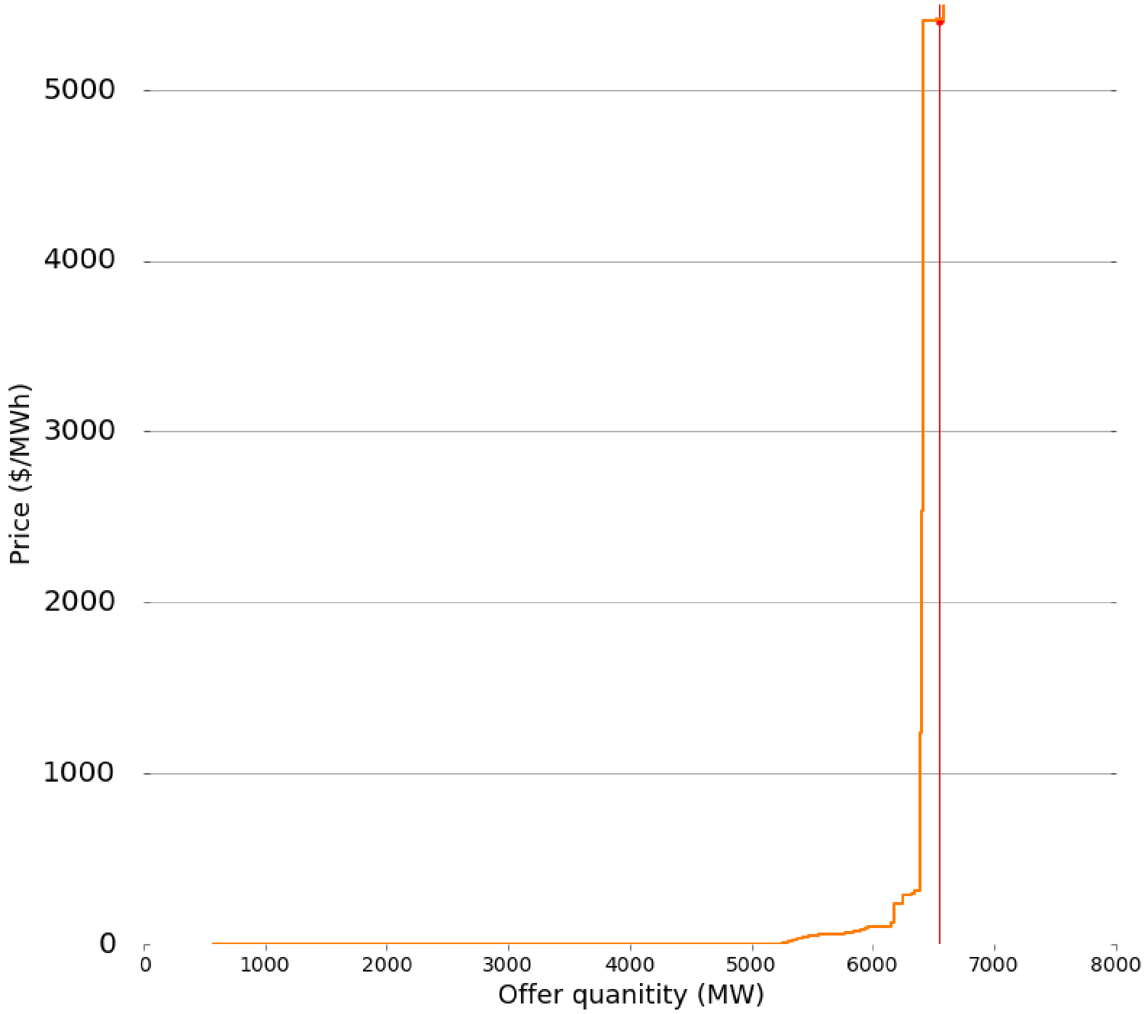
3.6 With both North Island thermal generation and HAMI-constrained South Island hydro generation not offered into the market, system conditions appear to have worsened during peak periods over the last year (despite a general lowering of peak demand in recent years).

3.7 The vSPD experiment outlined in Section 3 demonstrated that a small increase in demand can have a large impact on energy price. This indicates a trend toward increasingly tight supply conditions[5] and an offer curve very sensitive to small changes in demand during peak periods. This has an impact on the ability to accurately forecast prices–because a small error in the pre-dispatch demand forecast can have a large effect on the pre-dispatch price–creating uncertainty for participants and particularly the ability of the demand-side to react to them.

3.8 An example of this is illustrated in Figure 2 which shows the aggregated final pricing offer curve for TP35 on the 19 August.

[5] In terms of offers, though importantly not necessarily in terms of physical availability of plant.

Figure 2 Aggregated offer curve for TP35 on 19 August, 2014



3.9 The vertical line and red dot illustrate the cleared generation (+ instantaneous reserve) offers and the final energy price (referenced to Otahuhu).

3.10 When offered supply is tight, the large generator-retailers tend to offer enough generation so that (together with hedge contracts) they can cover their book positions. This results in offer curves that appear flat, at a low price, up to the company's book position, from where offered price tends to increase substantially (as pictured).

3.11 This offer structure means that during tight capacity constrained periods, a small change in system conditions can result in large unexpected changes in price. In these circumstances, pre-discpatch prices often do not accurately reflect the upcoming risk of generation shortfall and market participants consequently fail to react in time. This increases risk in the power system and the likelihood of a grid emergency developing, as was the case for both 27 May and 19 August.

3.12 On the 19 August at 3pm, forecast prices for the 5pm trading period (TP35, pictured) were under $100/MWh. Final prices cleared over 54 times higher at $5400/MWh at Otahuhu.

3.13 A grid emergency situation developed in the following trading periods, exacerbated by the inaccuracy of pre-dispatch forecast prices.

3.14 Table 2 contains pre-dispatch and final prices for Otahuhu at 3pm on 19 August 2014 as shown in Table 1.

3.15 Improving competition during peak demand periods should improve the shape of the offer curve and result in improved forecast prices. Several ways of achieving this are:

(a) as discussed above, re-alignment or lower perverse transmission pricing incentives

(b) increased demand-side participation and thermal generation commitment. Options for achieving this could be:

(i) through an ex-ante final price, currently being investigated by the Authority

(ii) other avenues to help forecasting, such as improvements to the System Operator's demand and wind forecasting methods.

3.16 Alternatively, or as well, a pre dispatch sensitivity schedule could be created where SPD is run with a small increase in demand, similar to the vSPD experiment conducted here. This could help signal the likelihood or risk of an upcoming shortage situation developing allowing participants the choice to react accordingly.

3.17 The Authority will raise the ideas in 3.14 (b)(ii) and 3.15 with the system operator.

4 Impact of transmission charges

4.1 The completion of the Wairakei ring upgrade in 2014 saw the last of Transpower's major grid builds. Since 2010, HVAC interconnection charges have increased by around 60%, while HVDC charges have doubled to $162m in the previous pricing year (falling to $145m for the most recent pricing year)[6].

4.2 The results of this enquiry suggest that:

(a) the recent increase in the HVDC charge combined with the methodology by which it is applied, appears to be limiting generation offers during peak demand periods

(b) conversely, the increased interconnection charge is leading to lower peak demand over the last several years reflecting an increased incentive for off-take customers to reduce load during these periods.

The effect of the HAMI-based HVDC charge on grid security

4.3 The 27 May emergency reflects that the HAMI-based HVDC charge encourages generators to withhold otherwise available generation capacity during peak periods. This increases the likelihood of grid emergency situations developing during these periods, requiring real-time remedial action by the System Operator. As Contact Energy noted in its recent submission on Transpower's TPM operational review[7]

[6] https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/year-specific-data-2013-14.pdf

[7] https://www.transpower.co.nz/about-us/industry-information/tpm-development/tpm-operational-review-submissions

"…the use of the HAMI to determine the HVDC charge discourages Contact from operating South Island generation at full capacity. There are no long term maintenance issues or resource consent limitations that prevent us from offering the Clutha's full capacity, the limiting factor is the HAMI charging regime."

4.4 This is shown in Table 2 below which shows settlement prices for August 19th, as well as what these would have been if Contact and Meridian were offering the South Island generation at full capacity. It shows that prices would have been lower in trading periods 35 and 36

Table 2: final prices and prices that would have prevailed if South Island generation was offered at full capacity 19 August 2014

TP	Approximate final prices at Benmore if South Island generation offered at full capacity	Final
TP35	$330	$5400
TP36	$408	$2400
TP37	$988	$9700
TP38	No change	$500
TP39	No change	$400
TP40	No change	$130

4.5 Under the TPM, the HVDC charge currently recovers the costs of the HVDC link from South Island generators. The charge is calculated for each HVDC customer, with the allocation of costs proportional to peak generation at each South Island generation location, based on HAMI (historical anytime maximum injection).

4.6 HAMI for a South Island generator at a South Island connection location is the higher of:

(a) the average of the 12 highest injections at that location during the capacity measurement period[8] for the relevant pricing year. Or

(b) the average of the 12 highest injections at that connection location during any of the four immediately preceding pricing years[9].

4.7 The above method incentivises a South Island generator to maintain peak injection at a connection location below the generator's average historic levels.

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8 The capacity measurement period means for any pricing year, the 12 month period starting 1 September and ending 31 August inclusive, immediately before the commencement of the pricing year (clause 3, Schedule 12.4 of the Code).

9 Clause 3, definitions, Schedule 12.4 of the Code

The doubling of the revenue to be recovered through the HVDC charge has exacerbated these incentives.

4.8 This creates a risk for grid security. As Contact noted in its submission, increasing peak injection potentially results in greatly increased transmission charges. In addition to this, the HAMI is also dependent on how other South Island generators offer. A strategy to decrease peak generation by one party means an increase in HAMI charge for all other parties, all other things remaining equal.

4.9 The following four factors give the Authority confidence that the HAMI charge is the cause of South Island generators not offering generation at capacity:

(a) Statements made by the generators.

(b) The fact that capacity is offered when a grid emergency has been declared means that there is no physical reason for the capacity not to be offered.[10]

(c) The fact that the HAMI creates the incentive to not offer full capacity.

(d) Trading periods 17, 18 and 19 on May 27, and 38 and 39 on August 19 would all have been used to calculate HAMI for Contact Energy if Transpower had not exercised its discretion under clause 34 of the TPM to adjust Contact Energy's HAMI.

4.10 The Authority's 2012 issues paper[11] recognised this and Transpower's current TPM operational review has considered the use of HAMI as a basis for allocating HVDC charges and possible future amendments. Both referenced the TPAG work from 2011. The TPAG Report concluded that HAMI-based charges created the following inefficiencies:

(a) Disincentives for investing in SI generation relative to NI generation.

(b) Competition effects favouring new generation investment in the SI by large incumbent generators.

(c) Generation dispatch inefficiencies arising from the HAMI price structure.

4.11 Transpower's review has proposed the following solutions.

(a) An capacity option, which in effect would be similar to placing a freeze on the Capacity Measurement Period used in the HAMI calculation.

(b) A per-MWh option which would be equivalent to increasing the number of peak periods used in the HAMI from 12 to 17520 periods per year.

The effect of RCPD and bona fide bid revisions on grid security

4.12 The interconnection charge is allocated based on each customer's demand at peak times. For the upper North Island and upper South Island, peak times are the half hours in which any of the 12 highest regional demands occur. For the lower North Island and lower South Island, peak times are the half hours in which

10 If capacity is offered, the Authority assumes that the relevant generator has assessed that it is very likely that Transpower will rely on its discretion in clause 34(2) of the TPM to adjust HAMI such that any additional offered generation does not impact on the calculation of the generator's HVDC charge.

11 http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c2119

any of the 100 highest regional demands occur. Regional demand for a half hour is the sum of all offtake quantities at all connection locations in the region.

4.13 On the 19 August, as it became apparent that the evening peak was likely to be a period used for the calculation of the interconnection charge, industrial North Island interruptible load providers started revising their demand bids lower during gate-closure and removing interruptible load offers at the same time.

4.14 Although concerning, this behaviour tends to have little effect on the capacity shortfall situation.

4.15 However, it is still worth considering this kind of behaviour in terms of an overall system perspective as well as the perspective of the individual party as there may be instances when this kind of behaviour could worsen a capacity shortfall.

(a) In terms of the overall perspective, in this particular case such behaviour had a near nett zero effect on the grid emergency (capacity shortfall). A lower demand will, in most cases, counteract the fall in interruptible load offers. However, if multiple North Island risks had been present, for example if two or three large CCGT's had been generating at the same level, such action from interruptible load providers may have exacerbated the capacity shortfall[12]. In these circumstances, one extra MW of interruptible load can enable two or three additional MWs of generation (1 MW from each of the risk setters) resulting in reserve prices two or three times higher than energy. This situation is relatively rare with the most recent case being TP39 on the 24 July 2014[13]. North Island reserve cleared at $800/MWh, double the energy price, indicating dual risk setters. In this instance a potential capacity situation may have been exacerbated by the bona fide withdrawal of industrial North Island interruptible load providers.

(b) In terms of the individual industrial interruptible load providers, the major price risk is the interconnection charge priced at the current interconnection rate of $114/kW. An additional risk lies in any possible nett difference between final nodal energy price and island reserve price[14].

4.16 As an individual participant's interconnection charge increases, the participant's incentive to reduce peak demand also increases. This may have contributed to the lowering demand at peak periods across NZ and is reflected by the fact that

12 Although it is unlikely that there will be a capacity shortfall when multiple CCGTs are operating.

13 And previous to this on the 18 August 2011.

14 During a capacity constrained period, reserve prices and energy prices will tend to become closely linked (essentially the market for reserve and energy combines into a single market). Industrial interruptible load providers therefore have a hedge on nodal energy price as they get paid a similar price for providing interruptible load, albeit at an island-wide price. Some risk may be apparent in the net difference between the nodal energy price and the island reserve price. For example, during trading period 37 on 19 August, an interruptible load provider at Otahuhu would have paid around $600/MWh more for energy than they would have been paid for providing interruptible load. Note: that this is a much better outcome than if no interruptible load had been offered at all and that the opposite is true in other regions, i.e., an interruptible load provider in the lower north island may have received more for interruptible load than it had to pay for energy. A move to a market with final pricing ex-ante would provide more price certainty for market participants in real time. The Market Design team at the Electricity Authority is currently investigating possible ex-ante market alternatives.

in the last seven years the interconnection revenue has increased by 70%, yet the interconnection rate has increased by 80%.

4.17 Under an RCPD-based interconnection charge, lower demand at peak times by one participant results in a higher share of interconnection charges for others. RCPD charging provides incentives for lower peak demand, and consequently incentives to delay capital investment. Continuing such a charging regime after a large grid build risks stranding transmission assets built to accommodate such peak periods.

4.18 The magnitude of this problem depends on the amount of Transpower's total revenue requirement that is recovered through the interconnection charge. Transpower's total revenue requirement is fixed by the Commerce Commission. Of that total revenue requirement, HVDC revenue is calculated separately. The remaining revenue, which relates to Transpower's AC assets, is recovered through the interconnection charge and the connection charge. The allocation between those charges depends on how connection and interconnection assets are defined.

4.19 For example, if the TPM was amended to adopt a deeper definition of connection assets, more assets would be connection assets, and connection charges would increase. That would reduce the revenue recovered through the interconnection charge, improving incentives for providers of interruptible load to remain connected during peak periods.

5 Effect of New Trading Conduct Provisions

5.1 Neither grid emergency raised concerns about trading conduct.

5.2 Clause 13.5A of the Code require generators and ancillary service agents to observe a high standard of trading conduct in relation to offers and reserve offers[15]. The trading conduct provisions came into effect on 17 July 2014 and are therefore relevant to the 19 August event.

5.3 The trading conduct provisions do not define the term "high standard of trading conduct" but do include a 'safe harbour' provision. If a participant's behaviour meets all three criteria defining the safe harbour, it will automatically comply with the requirement.

5.4 In summary, the three criteria a participant must satisfy to be in the safe harbour are that:

(a) it offers all of its available capacity – energy and reserve – that is able to operate in a trading period

(b) when it decides to submit, revise, or withdraw an energy or reserve offer, it does so as soon as it can

(c) when it is a pivotal supplier, either:

(i) prices and quantities in its offers do not result in a material increase in the price at any node (for generators) or island (for ancillary service agents) where it is pivotal. This is assessed by comparing prices in the immediately preceding trading period or another comparable trading period in which it was not pivotal

(ii) its offers when it is pivotal are generally consistent with its offers when it was not pivotal

(iii) it does not benefit financially from an increase in the price in the region where it is pivotal.

5.5 Due to low energy prices, some slow starting thermal generators were not offered into the market at all during the 19 August event. This was a longer term decision by the owners of the plant based on plant profitability and was signalled to the market well in advance. A similar situation was discussed in the Authority's decision paper [15] regarding the efficiency of prices in pivotal situations, along with concerns over the HAMI-based HVDC charge and possible issues with meeting criteria (a) of the safe harbour.

5.6 When prices are low, slow start thermal generation can become uneconomic to run. The decision paper quoted:

[While this might] not satisfy the first safe harbour criterion, the Authority does not expect that this would fall below a "high standard of trading conduct".

5.7 The Authority considers that the above applies to the 27 May and 19 August grid emergencies.

15 http://www.ea.govt.nz/development/work-programme/wholesale/efficiency-of-prices-in-pivotal-supplier-situations/development/decision-paper/

6 Conclusion

6.1 The Electricity Authority's objective is to promote competition in, reliable supply of, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

6.2 Recent grid emergencies–combined with current market conditions–have highlighted issues with transmission pricing. The result appears to be a power system at increased security risk during peak periods.

6.3 This can be improved by:

(a) addressing inefficient transmission pricing incentives, suggestions include:

(i) Moving away from the current HAMI charge to either a capacity or MWh charge.

(ii) Reducing transmission costs recovered through RCPD charges by deepening connection charges.

(b) Improving demand-side participation and thermal generation commitment through better certainty of prices by:

(i) improved demand forecasting

(ii) adopting an ex-ante final price or market of some form

(iii) possibly issuing a pre-dispatch sensitivity schedule.