# Locally net pivotal generation

## Market performance review

30 July 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 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

Two recent events – a planned outage of the Albury-Timaru transmission line on 20-22 February 2012 and a planned transformer outage at Stoke on 5 April 2012 – have highlighted the ability of locally net pivotal generators to elevate wholesale market prices to very high levels, such as to $3,000/MWh. A generator is *locally pivotal* when some of its generation is needed to meet demand in a region, and it *is locally net pivotal* when that generation exceeds the generator's own retail and hedge commitments in that region

The two events referred above are described in detail and an analysis is undertaken of the likelihood of generators being net pivotal at these two places and elsewhere in New Zealand. Comparison of recent behaviour and pricing outcomes with that observed historically during similar outages suggests that generators have recently adopted new pricing strategies when they find themselves to be locally net pivotal.

Very high prices may occur from time to time when supply is scarce. In an energy-only market, high prices during scarcity are efficient if they are needed to ration demand to available levels of supply or if they incentivise investment in last-resort plant that is able to diminish the scarcity situation. But such plant would only be called upon to operate very infrequently – hence the need for the high prices to recover its costs when it does operate.

In situations when generators have surplus energy but are locally net pivotal due to temporary transmission outages, high prices may or may not be efficient, and they could inhibit competition in the hedge and retail markets. Even if high prices in net pivotal situations are efficient it is generally very difficult at the time they occur to determine whether that is the case, which leads parties exposed to those prices to publicly question or criticise those prices. Confidence in the overall market arrangements can become a key issue even though net pivotal generation may occur over a small number of trading periods and its effects restricted to relatively isolated areas of the grid.

The analysis finds that net pivotal generation situations can be usefully categorised as:

- Type I – net pivotal generation in an isolated region;
- Type II – net pivotal generation in a transmission-constrained region; or
- Type III – net pivotal generation in a transmission-constrained region with a spring washer effect.

The scope for devising remedies to deal with a net pivotal generator is greater for Type II than it is for Type I, and for Type III relative to Type II. This stems from the different conditions that exist with each type.

The paper finds that the growing issue of net pivotal generation warrants the Authority's immediate attention to determine whether Code amendments can address the above concerns in ways that deliver long-term benefits to consumers.

Five proposals to address net pivotal situations are outlined and discussed, as a means of stimulating thinking about possible remedies. The five do not represent an exhaustive list of proposed remedies. Potential solutions can be readily identified but what is more difficult is working them through to ensure they will work in practice and not have unintended consequences worse than the issue they are aimed at addressing.

The paper proposes a set of design principles for any proposed remedy. A remedy for net pivotal situations must:

- be able to be described and understood by participants;
- ensure that the party best able to fix (or prevent) the net pivotal situation is incentivised to do so; and
- lead to efficient and predictable outcomes across a broad range of net pivotal generation manifestations.

The Authority announced in its Market Brief on 8 May 2012 that it was establishing a project to consider options for achieving efficient pricing during pivotal situations. The analysis in this paper will be fed into that process and the options identified in this paper are likely to be considered alongside others that arise during the course of the project.

# 1 Introduction and purpose of this report

1.1 Due to annual maintenance or project works, many transmission lines are taken out of service several times a year. Some of these transmission outages will separate one or more substations from the main grid and form an isolated region. The demand for power in this isolated region must be satisfied by generators residing in that isolated region.

1.2 If a generator is required to meet the demand of a local region during a transmission outage, this generator will be locally pivotal and has the *ability* to set the price in the local region. A locally pivotal generator is a generator that must be called upon to generate in order that all demand in an area is served. This can occur when there is insufficient transmission or other local generation to serve the local demand. If the quantity of this necessary generation is greater than the generator's own retail and hedge commitments in that same area, then the generator is 'locally net pivotal' and has a commercial *incentive* to set very high wholesale prices in the area during the period it is locally net pivotal.

1.3 A recent planned daily outage of the Albury-Timaru (ABY_TIM_1) transmission line from 20-22 February 2012 demonstrated the above point. During the time of this outage, Albury and Tekapo A substations were separated from the main grid and formed an isolated region and the demand in that region could only be met by the Tekapo A power station. The energy prices at Albury and Tekapo A were set by the energy offer from the Tekapo A plant and remained over $3,000/MWh throughout the outage.

1.4 A similar event occurred on 5 April 2012. On this day, transformer T3 at Stoke (STK_T3) was out of service as planned from 08:00 to 17:00. As a result, Cobb (COB), Motueka (MOT), Motupipi (MPI) and Upper Takaka (UTK) substations were separated from the main grid and formed an isolated region. The demand in this isolated region is mainly supplied by the Cobb power station located at the Cobb substation. During the time of this outage, the energy price in this isolated region stayed at or above $3,000/MWh.

1.5 Because these transmission outages will recur in the future, retailers and load customers in the affected regions will repeatedly face the risk of high energy prices unless they can acquire a hedge contract to cover their load during the time of transmission outages. Given the short-term monopoly situation that arises during such outages, buying a hedge is not a straightforward proposition.

1.6 However, the risk is not able to be hedged. The only party likely to be willing to sell a hedge is the net pivotal party and they will rationally want to earn from the hedge what they think they can earn from the spot market. The choice for counterparties (to the net pivotal generator) is to pay slowly through the hedge or pay quickly through the spot price. Either way, the counterparty will pay to the net pivotal generator the expected returns from being net pivotal.

1.7 This report provides information to participants about the issues at stake when a generator is locally net pivotal. The report will focus on the following:

(a) recent locally net pivotal generation at Tekapo A and Cobb;

(b) changes in offer behaviour of generators in isolated regions;

(c) extent to which this behaviour could be more widespread;

(d) implications for efficiency and competition; and

(e) possible remedies.

# 2 Recent locally net pivotal generation at Tekapo A and Cobb

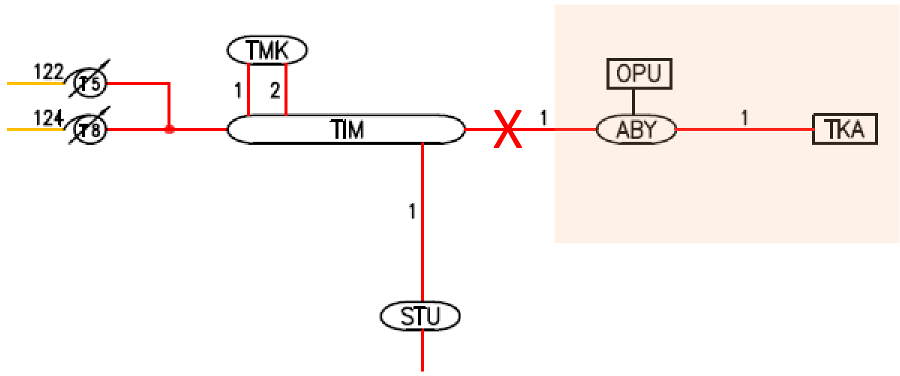
2.1 This section reviews the facts around the two recent events of locally net pivotal generation at Tekapo A (20-22 February 2012) and at Cobb (5 April 2012).

## Locally net pivotal at Tekapo A (TKA)

2.2 From 20-22 February 2012, there was a planned daily outage of the ABY_TIM_1 transmission line. This outage was planned to occur from 20-24 February 2012 according to the Planned Outage Co-ordination Process (POCP) but it finished two days earlier. Data shows that this outage was last confirmed in POCP on 15 December 2011 and first entered into the Wholesale Information and Trading System (WITS) on 11 February 2012. This means that market participants had 66 days warning of this outage.

2.3 When ABY_TIM_1 is out of service, the region, which includes the Albury and Tekapo A substations, is separated from the main grid and forms an isolated region (shaded area in Figure 1). There are two power stations in this isolated region. Opuha generation station[1] is a small hydro plant of 7.5MW capacity that is connected to the grid at the Albury substation. The Tekapo A power station is a larger hydro plant of 25MW capacity that is connected to the grid at the Tekapo A substation.

**Figure 1 Single line network diagram of affected region – TKA locally net pivotal**




Source: http://www.systemoperator.co.nz/maps-diagrams

2.4 During an outage of the ABY_TIM_1 single transmission line the demand at Albury and Tekapo A substations can be supplied by only these two power stations. Historical data shows that the maximum total load at Albury and Tekapo A is 7.3MW. Based on Opuha's capacity, this power station is capable of meeting the demand at Albury and Tekapo A during the outage. In this case Tekapo A is not net pivotal during the outage of ABY_TIM_1.

2.5 However, according to the system operator:

> the isolated region created by having ABY and TKA isolated from the wider grid has low load. Due to rough running ranges for Tekapo A generation, Opuha generation is requested (during the outage planning process) not to generate during the outages of ABY_TIM_1.[2]

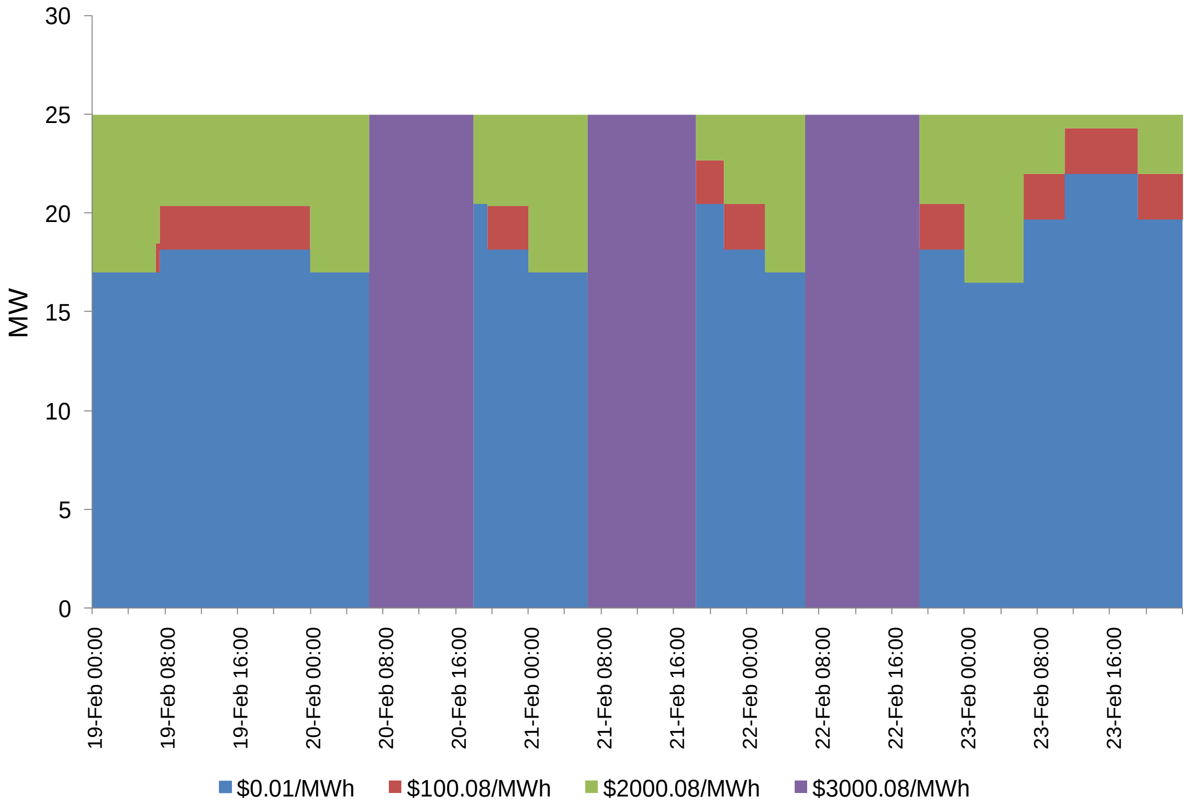
1 Opuha generation station is embedded in the Alpine Energy network behind ABY. It is un-offered and non-dispatched. Opuha is owned by Alpine Energy Ltd and operated by TrustPower.

2 Email on 3 April 2012 from the system operator about the reason for Opuha not generating during the ABY_TIM_1 outage.

In the micro power system that is created by islanding ANY and TKA it is not good practice to have two generators running. Their governors may 'fight' with detrimental effects for the islanded region.[3]

2.6 As a result, Tekapo A was the only generator in the isolated region during the ABY_TIM_1 outage. The offer price of Tekapo A generation was increased to $3,000/MWh from $0.01/MWh for all trading periods of the ABY_TIM_1 outage. Figure 2 presents the final offer stacks for all trading periods from 19-23 February 2012. The figure shows that the Tekapo A offer price increased to $3,000/MWh during the period of the ABY_TIM_1 outage.

**Figure 2 Energy offer stacks at Tekapo A, 19-23 February 2012**



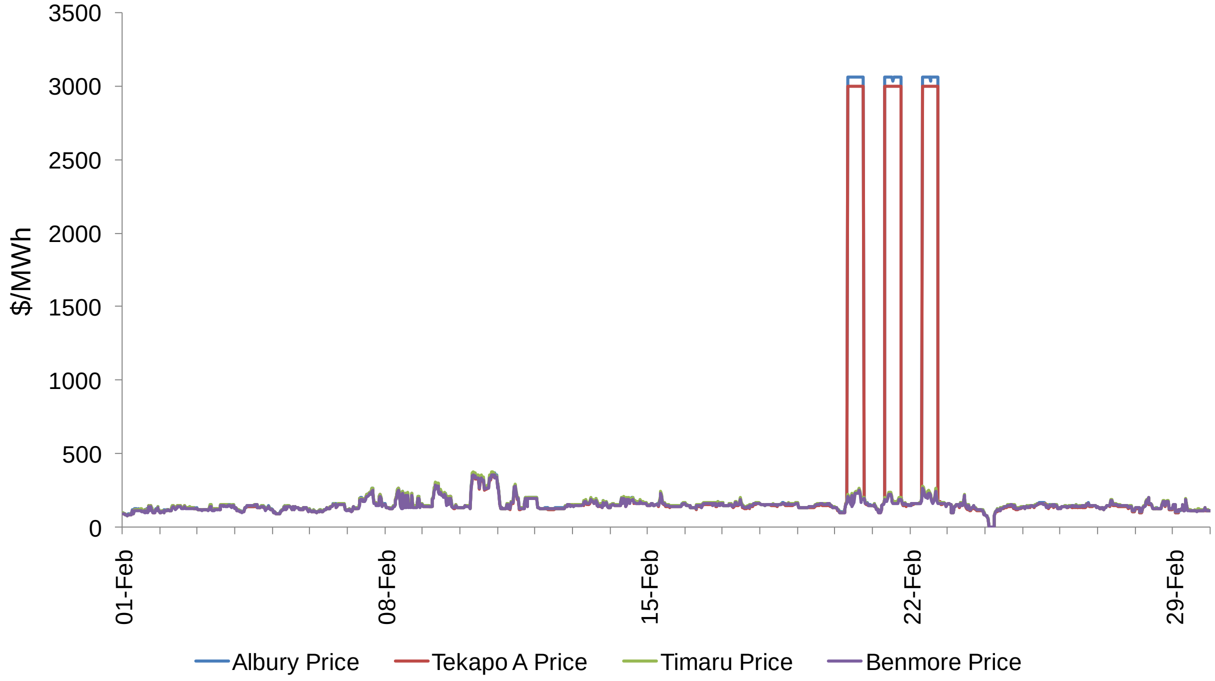

Source: Electricity Authority

Notes
1. ABY_TKA_1 was out of service from 07:30 to 17:30 on 20 February 2012
2. ABY_TKA_1 was out of service from 07:30 to 18:00 on 21 February 2012
3. ABY_TKA_1 was out of service from 08:30 to 18:00 on 22 February 2012

2.7 Because Tekapo A is the only supplier in the isolated region, the energy price in this region is set by Tekapo A. Figure 3 shows the energy prices at Albury, Tekapo A, Timaru and Benmore from 1-29 February 2012. The figure shows a significant increase of Albury and Tekapo A prices compared to the prices at the other two locations during the periods of the ABY_TIM_1 outage.

[3] Email on 25 July 2012 from system operator responding to draft review of locally net pivotal generation.

**Figure 3 Final energy prices at Albury, Tekapo A, Timaru and Benmore**




Source: Electricity Authority

2.8 Offer data show that Genesis Power Limited (Genesis) started offering all Tekapo A capacity at $3,000/MWh for all trading periods of ABY_TIM_1 outage at 17:35 on 17 February 2012.

2.9 The impact of energy offer changes at Tekapo A could be observed first through the weekly dispatch schedule (WDS) prices on 18 February 2012. The high prices were also evident at 14:00 on 19 February 2012 in the special winter schedule (SWS) and the pre-dispatch schedule (PDS). Finally, the schedule of dispatch prices and quantities (SDPQ) showed high prices four hours ahead of the event occurring. The SWS prices at Tekapo A stayed at $3,000.08/MWh for all trading periods of the ABY_TIM_1 outage in all SWS schedules. Similarly, the SDPQ prices at Tekapo A stayed at $3,000.08/MWh for all trading periods of the ABY_TIM_1 outage in all SDPQ schedules.

2.10 No parties approached Genesis or TrustPower Limited (TrustPower) to request a hedge before the outage occurred on 20 February 2012.

2.11 On 21 February 2012, a party approached Genesis to request a hedge at Tekapo A but the request failed to culminate in a transaction due to the difference of expected strike prices. On 22 February 2012, a party approached TrustPower to request a hedge at Albury. However, the request was not successful because TrustPower was unable to provide any cover during the outage of ABY_TIM_1.

2.12 This is not surprising as a locally net pivotal generator is unlikely to agree to a contract with an expected payoff less than that which could be attained in the wholesale spot market.

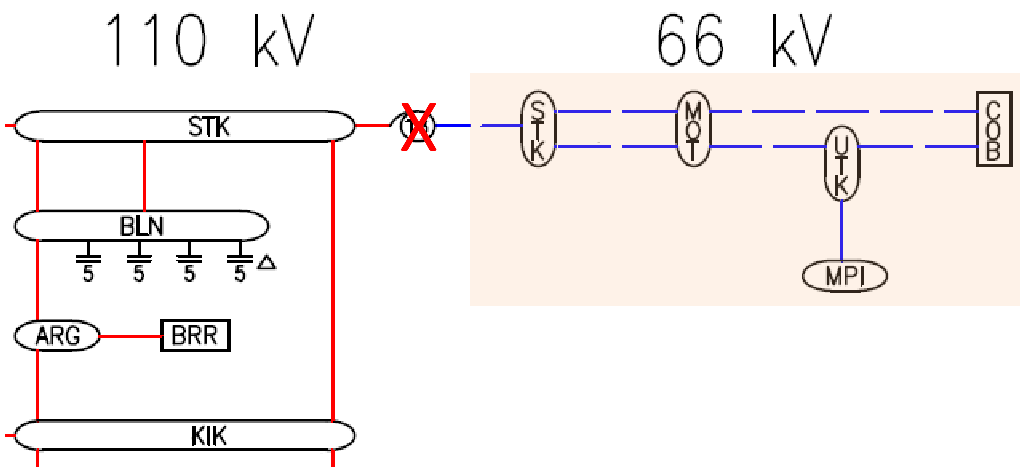
2.13 There was a planned outage of ABY_TKA_1 for 19-23 March 2012. This outage would separate Tekapo A from the main grid. Due to this planned outage, two parties approached Genesis to request a hedge at Tekapo A to cover the period of the ABY_TKA_1 outage. However, the hedge request was not successful due to the difference in perceived value of the hedge. This planned outage was delayed and subsequently cancelled on 19 May 2012 according to POCP.[4]

### Locally net pivotal at Cobb (COB)

2.14 On 5 April 2012 there was a planned outage of a 66kV transformer at Stoke (STK_T3) from 08:00 to 17:00. This outage was planned to be a one-day event according to POCP. Data shows that this outage was last confirmed in POCP on 20 February 2011 and first entered into WITS on 29 March 2012. This means that market participants had seven days' notice of this outage.

2.15 When STK_T3 is out of service the region comprising the Cobb, Motueka, Motupipi and Upper Takaka substations is separated from the main grid and forms an isolated region (shaded area in Figure 4). There is only one major power station in this region, located at Cobb. The Cobb power station is a hydro generating station of 32MW capacity.

**Figure 4 Single line network diagram of affected region – COB locally net pivotal**



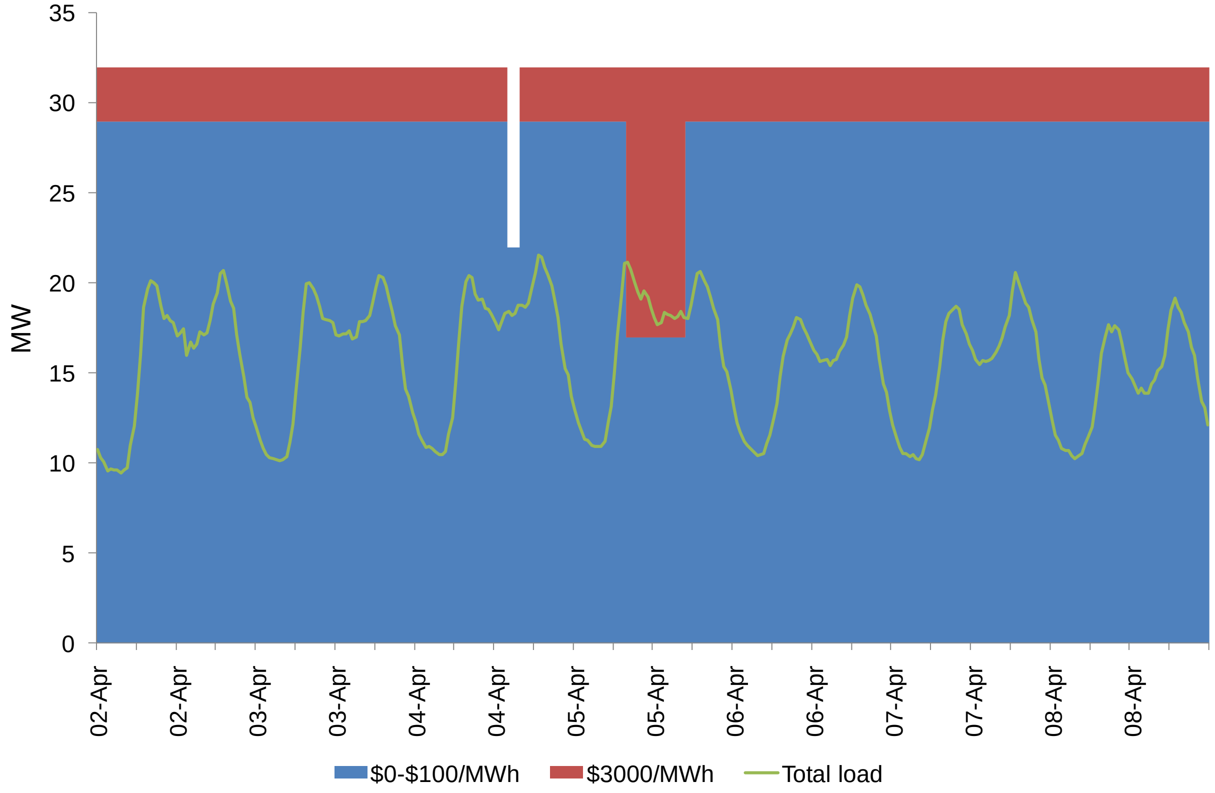

Source: http://www.systemoperator.co.nz/maps-diagrams

2.16 The demand in this region is mainly at Motueka and Motupipi. Historical data shows that the maximum total load at Motueka and Motupipi is 23.5MW. Based on Cobb's generating capacity, this power station is capable of meeting the demand at Motueka and Motupipi during the outage. Since there is no other major power station in this region, Cobb is pivotal during the outage of STK_T3.

2.17 Figure 5 shows the offer stacks at Cobb for all trading periods from 1-7 April 2012. The data shows that TrustPower moved 12MW of energy from the offer price band of less than $100/MWh to the offer price of $3,000/MWh for trading periods from 08:00 to 17:00. These offer revisions were perfectly coincident with the planned outage of STK_T3.

4 Around 16-19 March 2012 the planned outage was initially cancelled and then delayed from 19-23 March 2012 until 21-25 May, according to the POCP. The delay was because Genesis made their Tekapo A plant unavailable for some of the original planned dates, ie 19-23 March 2012. However, in a move unrelated to the delay, the outage, which was now planned for 21-25 May 2012, was cancelled on 19 May 2012 due to consideration of the hydro storage situation. The cancellation decision was made after receiving feedback at the weekly industry teleconference regarding hydrology.

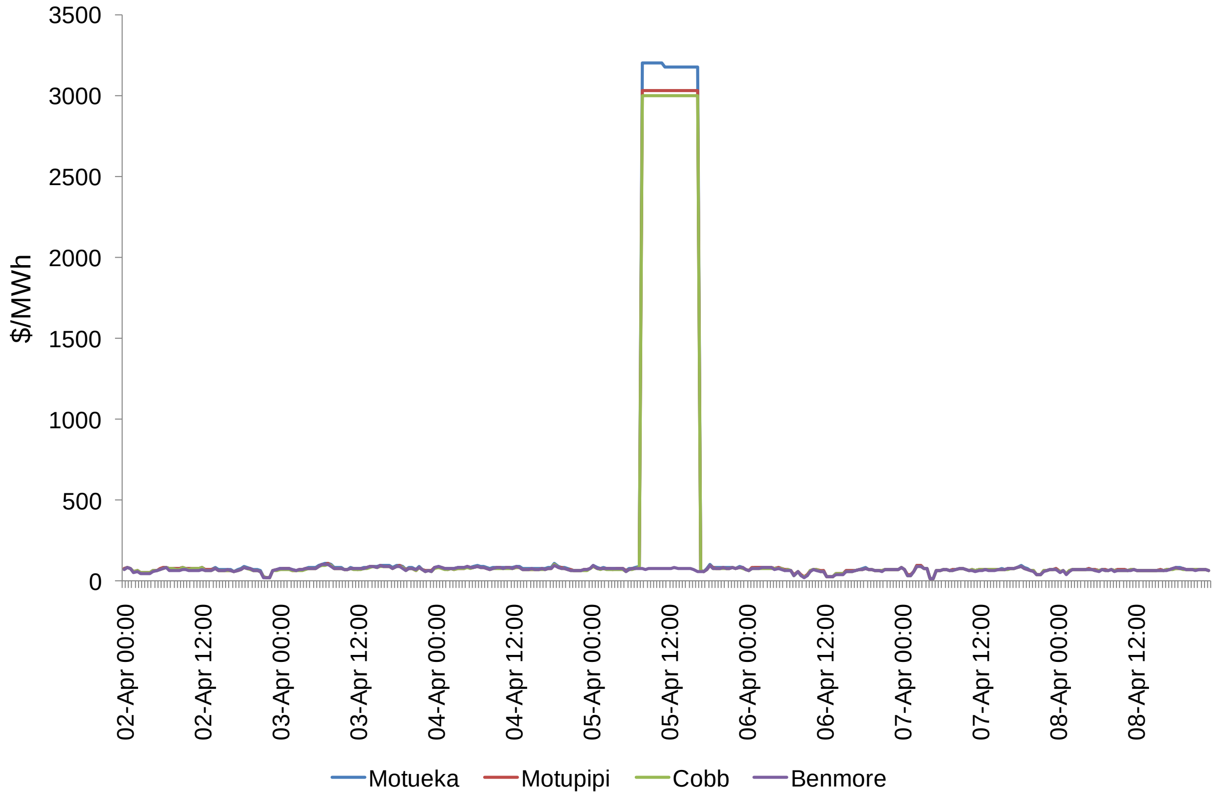
**Figure 5 Energy offer stacks at Cobb, 2-8 April 2012**




Source: Electricity Authority

2.18 Only 17MW of energy was offered below $100/MWh and 15MW of energy was offered at $3,000/MWh. Throughout the STK_T3 outage, the total load at MOT and MPI stayed above 17MW. As a result, energy prices at Cobb, Motueka and Motupipi were equal to or higher than $3,000/MWh for all trading periods from 08:00 to 17:00 on 5 April 2012, as illustrated in Figure 6.

**Figure 6 Final energy prices at Motueka, Motupipi, Cobb and Benmore**




Source: Electricity Authority

2.19 Offer data shows that TrustPower started restructuring its energy offer at Cobb for all trading periods of the STK_T3 outage at 09:58 on 3 April 2012. The new energy offer had 17MW in the $89.74/MWh price band and 15MW in the $3,000/MWh price band. This offer was unchanged and became the final offer.

2.20 The impact of the energy offer change at Cobb could be observed through SWS prices and SDPQ prices. The SWS prices at Cobb stayed at $3,000/MWh for all trading periods of the STK_T3 outage in all SWS schedules starting from 14:00 on 4 April 2012. Similarly, the SDPQ prices at Cobb stayed at $3,000/MWh for all trading periods of the STK_T3 outage in all SDPQ schedules.

2.21 At 17:17 on 4 April 2012, a party approached TrustPower to request a hedge at Cobb. No hedge agreement was reached. TrustPower indicated that it was not able to price a hedge at this point, and indicated that even if it were able to price a hedge, the only price it could offer would be the spot price for this period.[5]

2.22 Once again, this is not surprising because, if TrustPower was behaving rationally, it would be unlikely to agree to a contract with an expected payoff less than what it could attain in the wholesale spot market.

5 Letters from market participants responding to the request for information to support this market performance review, 20 April 2012.

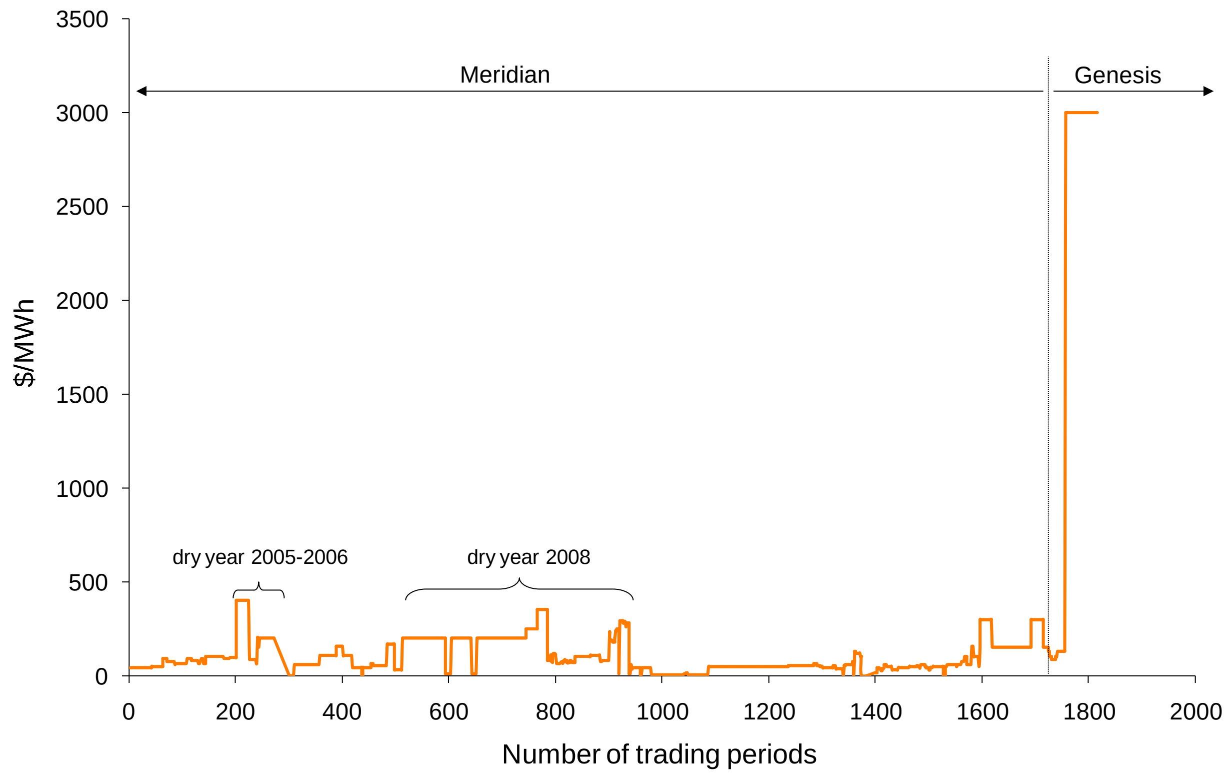
# 3 Changes in offer behaviour of generators in isolated regions

## Historical offer behaviour at Tekapo A

3.1 According to the system operator, outages of the ABY_TIM_1 and/or the ABY_TKA_1 transmission lines occur for about five to 10 days per year. Meridian Energy Limited (Meridian) owned the Tekapo power stations until 1 June 2011 at which point Genesis became the owner. These two companies appear to have quite different pricing strategies with respect to the output of Tekapo A.

3.2 According to historical data, the maximum total load of Albury and Tekapo A is 7.24MW. Figure 7 shows the marginal energy offer price of the first 8MW from Tekapo A during the time of ABY_TIM_1 or ABY_TKA_1 outages. The figure covers the period from 1 May 2004 to 1 April 2012. The data shows a marked increase of the marginal energy offer price during the ABY_TIM_1 outage event on 20-22 February 2012.

**Figure 7 Weighted-average offer price of the first 8MW at Tekapo A**
When ABY_TIM_1 or ABY_TKA_1 is out of service




Source: Electricity Authority

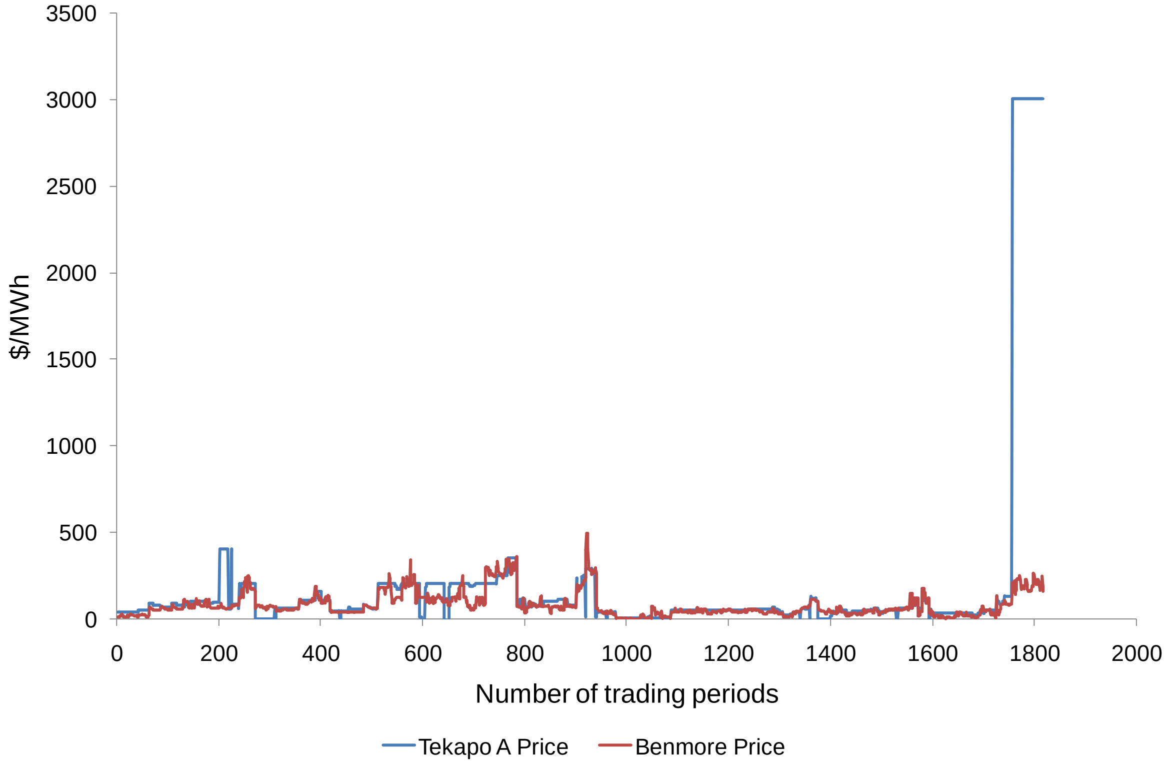
Notes:
1. Only the first 8MW offered is considered because total ABY and TKA load is less than 8MW.
2. Only the trading periods of the ABY_TIM_1 or ABY_TKA_1 outage are included.
3. The X axis only shows the periods of transmission outages over the time rather than the continual time interval since 1 May 2004.

3.3 Figure 7 shows that under Meridian ownership, the energy offer price at Tekapo A during the time of the ABY_TIM_1 or ABY_TKA_1 transmission outages increased on occasion, but was never higher than $500/MWh. The high energy offer price at Tekapo A mostly occurred during 2005-

2006 and 2008 dry years. The recent outage of ABY_TIM_1 from 20-22 February 2012 coincided with an increase of the Tekapo A energy offer price to $3,000/MWh.

3.4 Figure 8 compares the energy price at Tekapo A with the energy price at Benmore during the periods of the ABY_TIM_1 or ABY_TKA_1 outage from 2004 to 2012. The figure shows that the energy price at Tekapo A was sometimes higher and sometimes lower than the energy price at Benmore. Prior to the event on 20-22 February 2012, the price at Tekapo A never exceeded $400.60/MWh, and the maximum difference between the two prices was $343.30/MWh.

**Figure 8 Final energy prices at Tekapo A and Benmore during ABY_TIM_1 or ABY_TAK_1 outage**



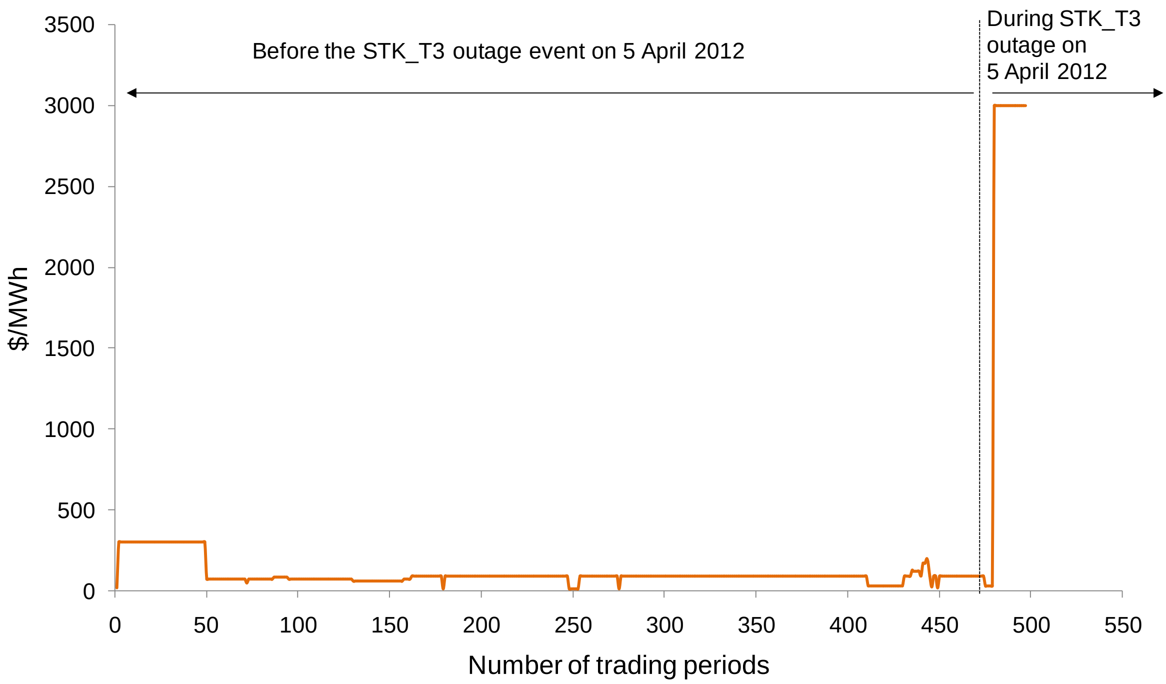

Source: Electricity Authority

Notes:
1. Data from 1 May 2004 to 30 April 2012.
2. Only the trading periods of the ABY_TIM_1 and/or the ABY_TKA_1 outage are included.

## Historical offer behaviour at Cobb

3.5 Data from 2004 to 2012 shows that the outage of STK_3 occurs 30 hours each year on average. Figure 9 shows the changes in energy offer prices at Cobb during historical STK_T3 outages. The figure covers the period from 1 May 2004 to 1 April 2012. The data shows a significant increase of the marginal energy offer price of the first 18MW at Cobb during the outage event on 5 April 2012.

**Figure 9 Marginal offer price of the first 18MW offered at Cobb during the STK_T3 outage**

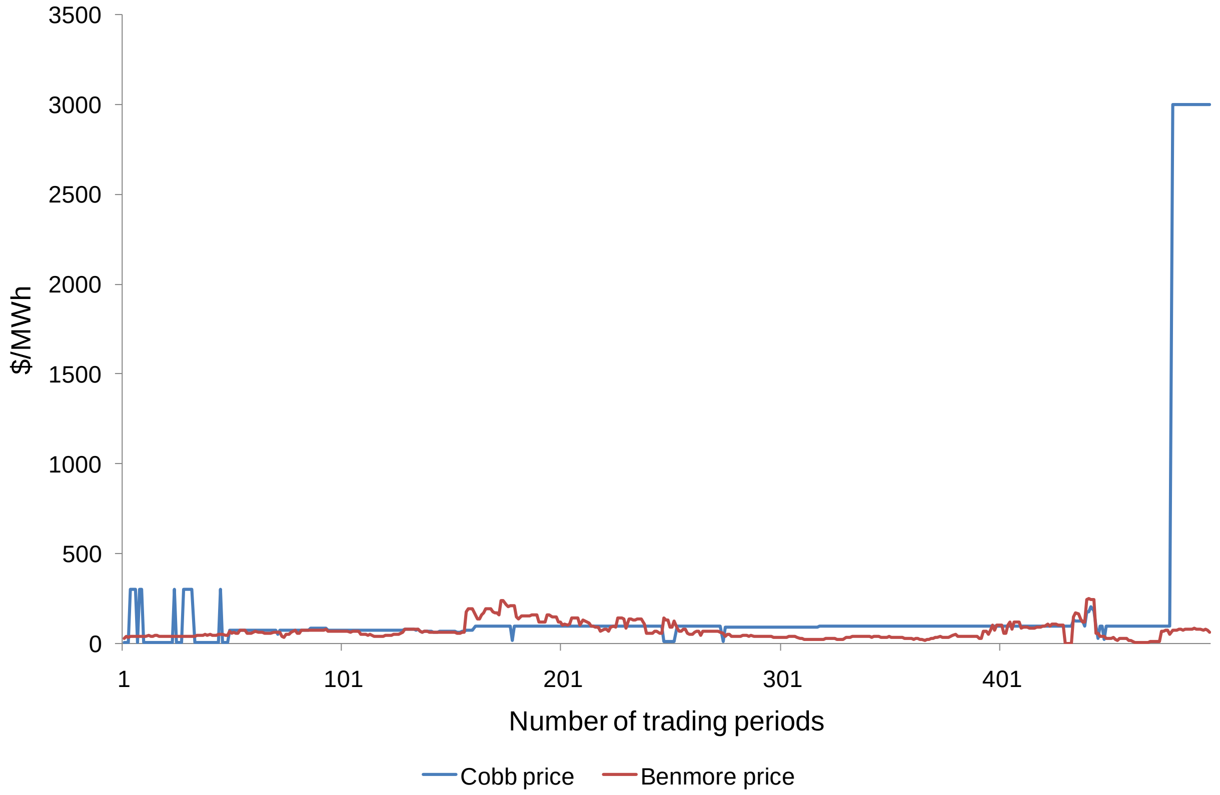



Source: Electricity Authority

Notes:
1. Data from 1 May 2004 to 30 April 2012.
2. Only the first 18MW offer is considered because the total of MOT and MPI load is around 18MW on average.
3. Only the trading periods of the STK_T3 outage are included.
4. The X-axis refers only to the number of periods of transmission outage.

3.6 Figure 10 compares the energy price at Cobb and the energy price at Benmore during the periods of the STK_T3 outages from 2004 to 2012. The figure shows that the energy price at Cobb was sometimes higher and sometimes lower than the energy price at Benmore. Prior to the event on 5 April 2012, the price at Cobb never exceeded $300/MWh and the maximum difference between the two prices was $261.60/MWh.

**Figure 10 Final energy prices at Cobb and Benmore during the STK_T3 outage**




Source: Electricity Authority

Notes:
1. Data from 1 May 2004 to 30 April 2012.
2. Only trading periods of STK_T3 outage are included.
3. The X-axis refers only to the number of periods of transmission outage.

## Offer behaviour summary

3.7 Studying the historical offers at these two locations reveals a change of offer behaviour of the net pivotal generator in an isolated region. Such behaviour would be expected to occur again whenever a similar situation arises in the future. No other similar incidents were identified at these nodes in the historical data.

# 4 The potential for locally net pivotal situations

4.1 Locally net pivotal generation can be classified into three types:

(a) Type I – Net pivotal generation in an isolated region.

(b) Type II – Net pivotal generation in a transmission-constrained region.

(c) Type III – Net pivotal generation in a transmission-constrained region with a spring washer effect.

4.2 Type I locally net pivotal generation occurs when a single generator is able to supply all of the power in an isolated region. In this situation the only generator in the isolated region is very likely to be locally net pivotal. Hence, it will have commercial incentives to set the price in the region as high as possible, limited only by a perceived or real threat of regulatory or political intervention, or a negative impact to its own reputation. This situation can happen for regions that depend on only one transmission line or transformer to import/export energy. Examples of this type of locally net pivotal generation are the cases previously mentioned, Cobb and Tekapo A hydro plant.

4.3 Type II locally net pivotal generation occurs when both generation and transmission are used to satisfy the demand in a partially isolated (or transmission constrained) region. In such cases, the maximum transmission capacity into the region is less than the total demand, necessitating the need for local generation to make up the difference. The isolation of the region applies only in the sense that no further transmission into the region is possible once the transmission limit is reached. Examples of this type of locally net pivotal generation are discussed below and include Karapiro, Arapuni, Waikaremoana and the Waipori hydro plant at Halfway Bush.

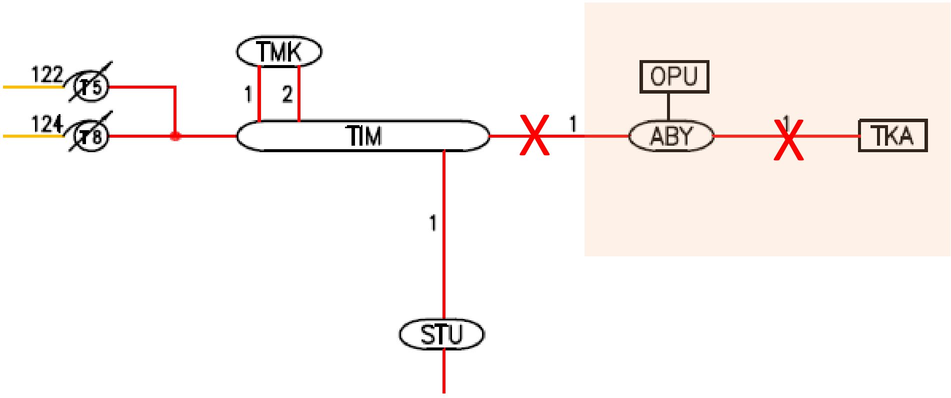
4.4 Type III locally net pivotal generation occurs when a generator has little or no contracted load in the region and conditions exist that enables the generator to induce a spring washer effect. Such conditions include a transmission outage and/or unusually high demand. Examples of this type of locally net pivotal generation can be seen at the Waikaremoana power scheme.

## Type I – locally net pivotal generation in an isolated region

### Tekapo A

4.5 When ABY_TIM_1 is out of service the region including the Albury and Tekapo A substations is separated from the main grid and forms an isolated region (shaded area in Figure 11).

**Figure 11 Single line network diagram of affected region – TKA locally net pivotal**




Source: http://www.systemoperator.co.nz/maps-diagrams

4.6 Due to rough running ranges for Tekapo A generation, the system operator requests that Opuha not generate during outages of ABY_TIM_1. This request occurs during the outage planning process. Consequently, the demand at Albury and Tekapo A is only able to be supplied by the Tekapo A power station and this means that the prices at Albury and Tekapo A will be set by the offer of Tekapo A's generation.

4.7 The system operator has discretion to instruct plant to operate in such a manner that its principal performance objectives are achieved. These objectives do not relate to promoting competition or developing more expensive options (from the system operator's perspective) that enable greater competition. The Authority received conflicting advice as to the rough running range of the Tekapo A station (a Kaplan turbine, which may not have a rough running range). To consider Opuha station as an alternative to Tekapo A, a special arrangement to dispatch the plant from the system operator would have been required. A more complex local frequency keeping arrangement may also have been required.

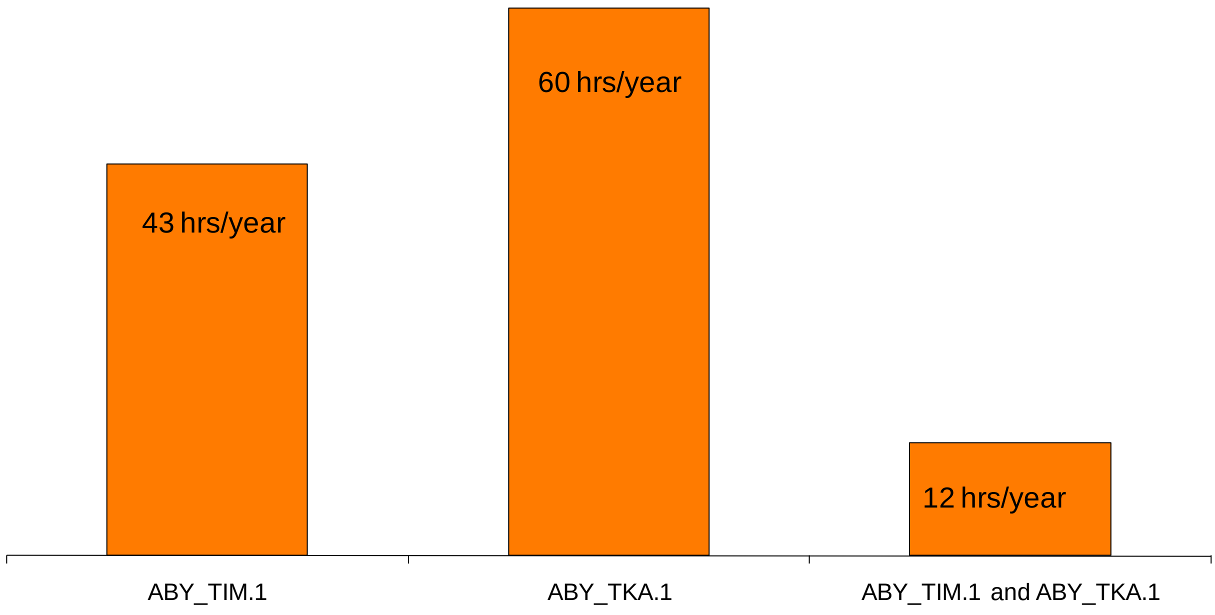
4.8 In the case of ABY_TKA_1 outages, only Tekapo A is separated from the main grid. The demand at Tekapo A is supplied by the Tekapo A power station and the price at Tekapo A will be set by the offer of the Tekapo A power station.

4.9 In the case of both ABY_TIM_1 and ABY_TKA_1 outages the Albury price will be zero and the Tekapo A situation is similar to the case of an ABY_TKA_1 outage.

4.10 In any of the above outage situations, the company that owns Tekapo A power station is always net pivotal. A supplier is net pivotal if its generation output is higher than its fixed-price retail load and hedge commitments. In this case, because the company's share of retail load and hedges in the isolated region is likely to be less than 100 percent, the Tekapo A power station's owner will profit from increasing the market price at Tekapo A.

4.11 ABY_TIM_1 and ABY_TKA_1 transmission lines are taken out of service for maintenance at least once a year. Data between May 2004 and May 2012 show that ABY_TKA_1 was out of service for 72 hours per year on average and ABY_TIM_1 was out of service (without an ABY_TKA_1 outage) for 43 hours per year on average (see Figure 12).

**Figure 12 Average amount of time ABY_TIM_1 and/or ABY_TKA_1 are out of service**




Source: Electricity Authority

Note: Based on data from May 2004 to May 2012.

4.12 According to the system operator, these outages normally occur during autumn and last for 5-10 days. They are usually day-time outages during the period 07:00 to 17:00.

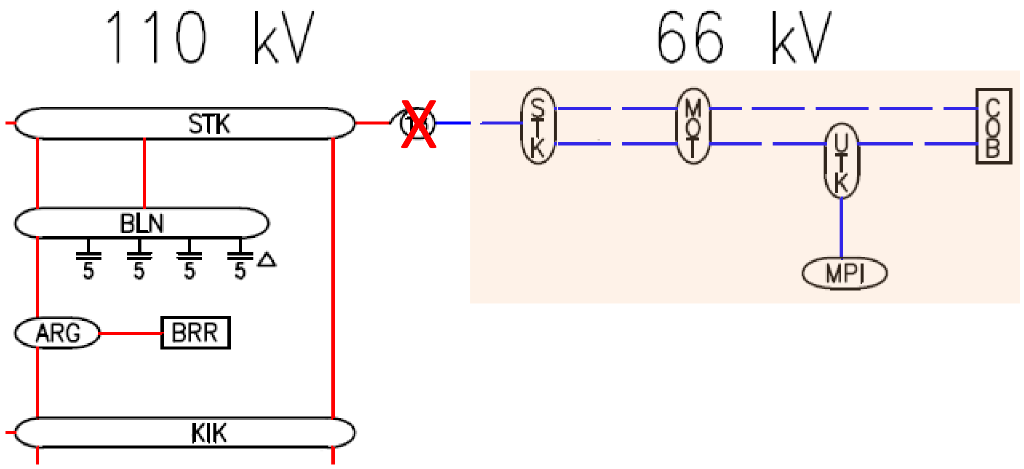
4.13 In summary, when ABY_TIM_1 or ABY_TKA_1 is out of service, the Tekapo A hydro plant is very likely to be locally net pivotal, as the sum of its retail and hedge commitments is very likely to be less than the local demand. It therefore has a commercial incentive to set a very high price, with an ill-defined upper bound.

### Cobb

4.14 The STK_T3 transformer is out of service for about 30 hours per year on average according to the 2004-2012 data. When STK_T3 is out of service Cobb (COB), Motueka (MOT), Motupipi (MPI) and Upper Takaka (UTK) substations separate from the main grid and form an isolated region (shaded area in Figure 13). The demand in this isolated region is mainly supplied by the Cobb power station located at the Cobb sub-station.[6]

[6] The Onekaka hydro power plant of 1MW is embedded in this region.

**Figure 13  Single line network diagram of affected region – COB locally net pivotal**




Source: http://www.systemoperator.co.nz/maps-diagrams

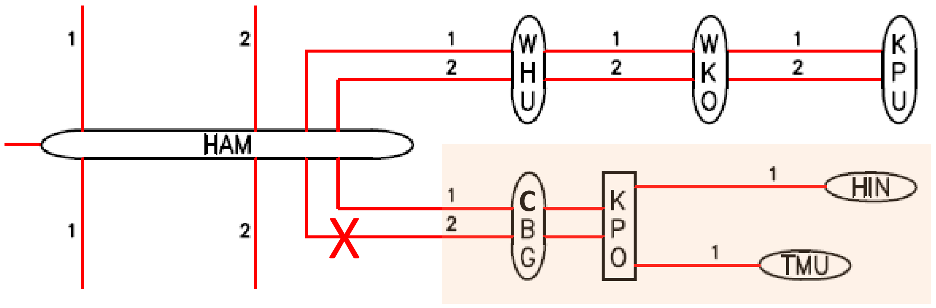
4.15 During the time of this outage, the energy price in the isolated region is set by the energy offer price at the Cobb power station. It is very likely that the owner of the Cobb power station is net pivotal in this isolated region, as the sum of its retail and hedge commitments is very likely to be less than the local demand. As a result, it is profitable to increase the energy offer price at Cobb as high as possible to maximise profit during the time of the STK_T3 outage.

## Type II – Net pivotal generation in a transmission-constrained region

### Karapiro

4.16 Historical data shows that the HAM_KPO_1 or HAM_KPO_2 transmission line is out of service for about 128 hours per year on average. When either HAM_KPO_1 or HAM_KPO_2 is out of service the energy demand at Cambridge (CBG), Hinuera (HIN) and Te Awamutu (TMU) is provided by Karapiro generation (KPO) and/or through the transmission line that remains in service.

**Figure 14  Single line network diagram of affected region – KPO locally net pivotal**



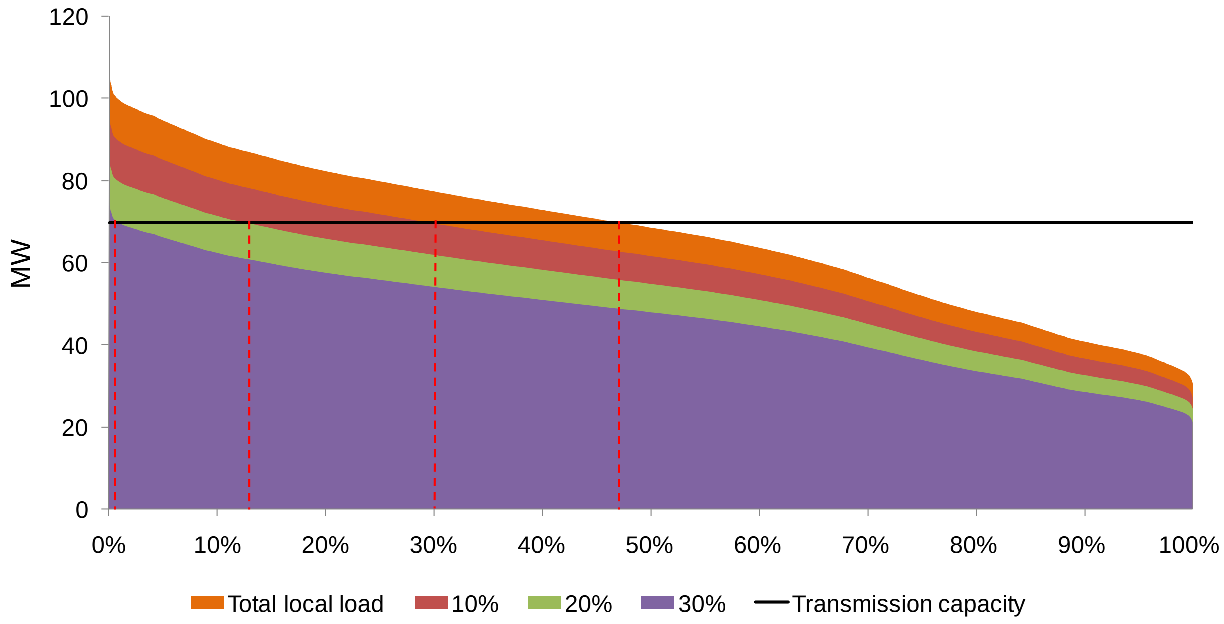

Source: http://www.systemoperator.co.nz/maps-diagrams

4.17 The maximum capacity of each HAM_KPO transmission line is 69.8MW (winter rating) and the maximum total load at CBG, HIN and TMU can be as high as 111MW (16 August 2011 TP 37). The maximum total load at CBG, HIN and TMU during an outage of either HAM_KPO_1 or HAM_KPO_2 was 99.7MW (23 November 2011 TP 16).

4.18 Figure 15 represents the total load at Cambridge, Hinuera and Te Awamutu from 1 May 2011 to 30 April 2012 as a load duration curve (LDC).[7] Given the maximum capacity of the remaining transmission line of 69.8MW, Karapiro generation is pivotal in the region 47 percent of the time if one of the HAM_KPO transmission lines is out of service. Depending on the contracted load of Mighty River Power Limited (MRP) in this region Karapiro can be net pivotal. MRP owns the Karapiro power plant.

4.19 The 10, 20 and 30 percent lines represent the load in the region excluding MRP contracted load with the assumption that MRP contracted load equals 10, 20 and 30 percent of total load respectively. If MRP contracted load equalled 10 percent of total load, KPO could be net pivotal 30 percent of the time. Similarly, if MRP contracted load equalled 20 percent of total load, KPO could be net pivotal 13 percent of the time. If MRP contracted load was 30 percent of total load, KPO could be net pivotal less than one percent of the time.

**Figure 15 Propensity for Karapiro to become locally net pivotal**




Source: Electricity Authority

Notes:
1. Data from 1 May 2011 to 30 April 2012.
2. The upper boundary of the 10 percent area line represents the remaining load of the region after excluding MRP contracted load which is assumed to be 10 percent of total load. Similar for 20 and 30 percent cases.

4.20 Historical pricing data does not suggest any occurrences of high prices due to locally net pivotal situation at Karapiro. Prior to May 2007, there was a 25MW cogeneration station at Te Awamutu. After the decommissioning of the Te Awamutu cogeneration plant in 2007, Karapiro could be pivotal when either HAM_KPO_1 or 2 was out of service. However, the historical pricing data suggests that Karapiro was never net pivotal. It may be the case that MRP had such a high contract load in the region that Karapiro could never be locally net pivotal.

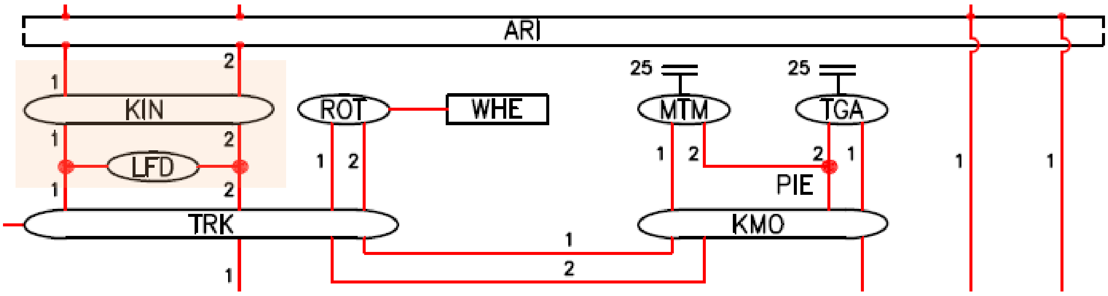
4.21 Because the load data shows a high likelihood of KPO being pivotal during a HAM_KPO_1 or HAM_KPO_2 outage, this region is considered to be potentially exposed to locally net pivotal generation during a transmission outage.

[7] An LDC illustrates the percentage of time (X-axis) that the total load is above certain amount MW (Y-axis).

### Arapuni

4.22 Historical data shows that the Kinleith (KIN) thermal power station is out of service for 25 days per year on average. With the Arapuni (ARI) split in place[8], the local load at Kinleith and Lichfield (shaded area in Figure 16) is supplied by some of the Arapuni hydro units and through two transmission lines from Tarukenga (TRK) to Lichfield (LDF) whenever the KIN thermal power station is out of service. The N-1 security limit applied for these two transmission lines is approximately 65MW and the maximum total load at KIN and LFD can be as high as 102MW (trading period 18 on 28 September 2011).

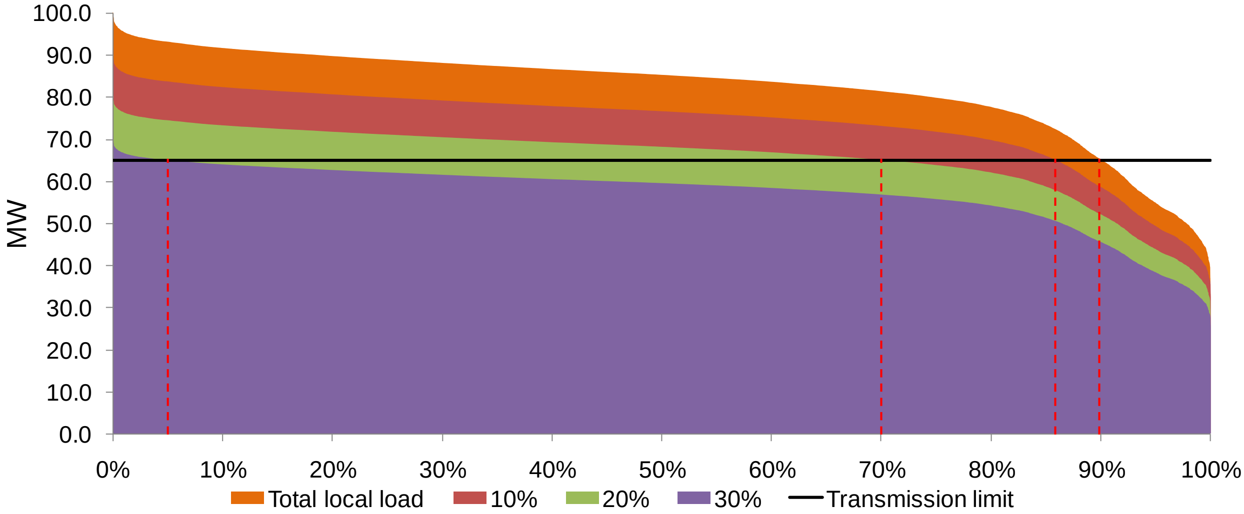
**Figure 16 Single line network diagram of affected region – ARI locally net pivotal**




Source: http://www.systemoperator.co.nz/maps-diagrams

4.23 Figure 17 represents the LDC for KIN and LFD from 1 May 2011 to 30 April 2012. Assuming the KIN thermal power station is not in service and the transmission limit is 65MW, the Arapuni hydro plant is pivotal in the region 90 percent of the time if the KIN thermal power station is out of service. Depending on the contracted load of MRP at KIN and LFD, Arapuni can be net pivotal.

**Figure 17 Propensity for Arapuni to become locally net pivotal**




Source: Electricity Authority

Notes:
1. Data from 1 May 2011 to 30 April 2012.
2. The upper boundary of the 10 percent area line represents the remaining load of the region after excluding MRP contracted load which is assumed to be 10 percent of total load. Similar

[8] Arapuni bus is split to relieve Arapuni generation constraints and also reduce system losses – Customer advice notice on 23 September 2011

for 20 and 30 percent cases.

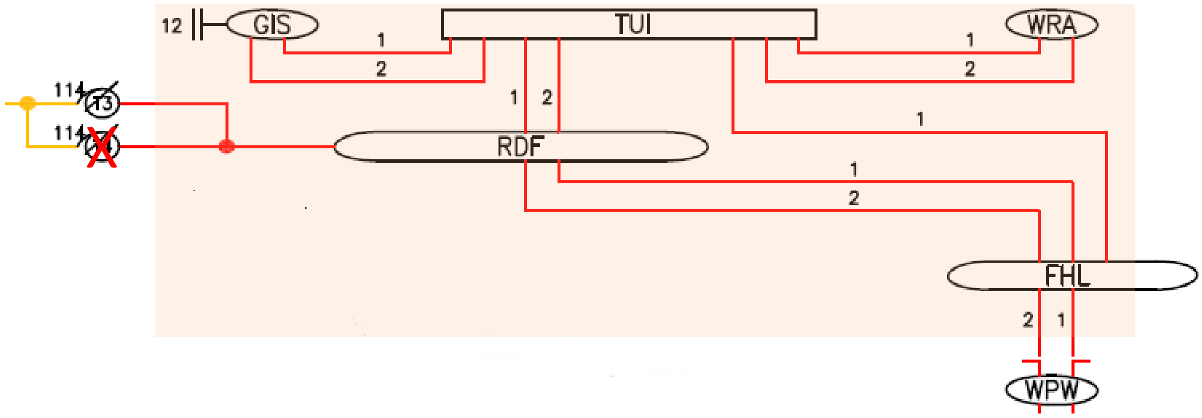
4.24 The 10, 20 and 30 percent areas represent the load in the region excluding MRP contracted load with the assumption that MRP contracted load equals 10, 20 and 30 percent of total load respectively. If MRP contracted load equalled 10 percent of total load, the ARI hydro plant could be net pivotal 86 percent of the time when the Kinleith thermal power station is out of service. Similarly, If MRP contracted load equalled 20 percent of total load, the ARI hydro plant could be net pivotal 70 percent of the time. If MRP contracted load was 30 percent of total load, the ARI hydro plant could be net pivotal six percent of the time.

4.25 The Arapuni hydro plant becoming locally net pivotal can be avoided completely if the system operator closes the ARI split whenever the KIN thermal power station is out of service and local load is high.

### Waikaremoana power scheme

4.26 Historical data show that RDF_T3 or T4  is out of service for 140 hours per year on average. When either RDF_T3 or T4  is out of service, the energy demand at Redclyffe (RDF), Fernhill (FHK), Tuai (TUI), Wairoa (WRA) and Gisborne (GIS) is provided by the Waikaremoana power scheme (WKA) injecting into the grid at TUI and/or through the in-service transformer (see shaded area in Figure 18).

**Figure 18  Single line network diagram of affected region – WKA locally net pivotal**



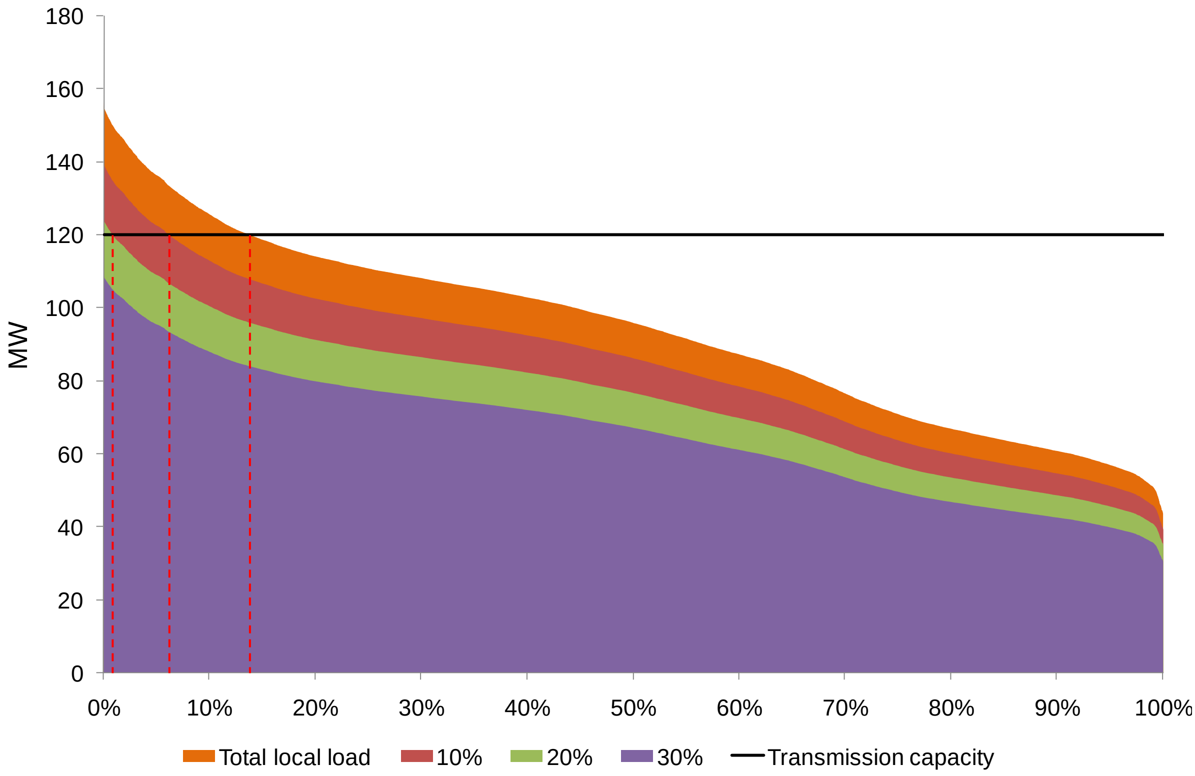

Source: http://www.systemoperator.co.nz/maps-diagrams

4.27 The maximum capacity of each transformer is 120MW (winter rating) and the maximum total load at RDF, FHL,TUI, WRA and GIS can be as high as 156MW (16 Aug 2011 TP 36). The maximum total load at RDF, FHL,TUI, WRA and GIS during the outage of either RDF_T3 or T4 was 151.5MW (6 May 2010 TP 37).

4.28 Figure 19 represents the LDC for Redclyffe, Fernhill, Tuai, Wairoa and Gisborne from 1 May 2011 to 30 April 2012. Given the maximum capacity of one transformer of 120MW, WKA is pivotal in the region 14 percent of the time if one of the two transformers is out of service. Depending on the contracted load of Genesis in this region, WKA can also be net pivotal.

4.29 The 10, 20 and 30 percent areas represent the load in the region excluding Genesis' local contracted load with the assumption that Genesis' local contracted load equals 10, 20 and 30 percent of total local load respectively. If Genesis' contracted load equalled 10 percent of total load, WKA could be net pivotal six percent of the time. Similarly, if Genesis' contracted load equalled 20 percent of total load, WKA could be net pivotal less than one percent of the time. If Genesis' contracted load was greater than 30 percent of total load, WKA could never be net pivotal.

**Figure 19 Propensity for Waikaremoana to become locally net pivotal**




Source: Electricity Authority

Notes:
1. Data from 1 May 2011 to 30 April 2012
2. The upper boundary of the 10 percent area line represents the remaining load of the region after excluding Genesis' contracted load which is assumed to be 10 percent of total load. Similar for 20 and 30 percent cases.

4.30 Historical pricing data does not show any locally net pivotal situation of WKA generation. There were three trading periods on 4 May 2010 and one trading period on 5 May 2010 when RDF_T3 was out of service and the price separation between RDF220 and RDF110 was significant (around $4,700/MWh).

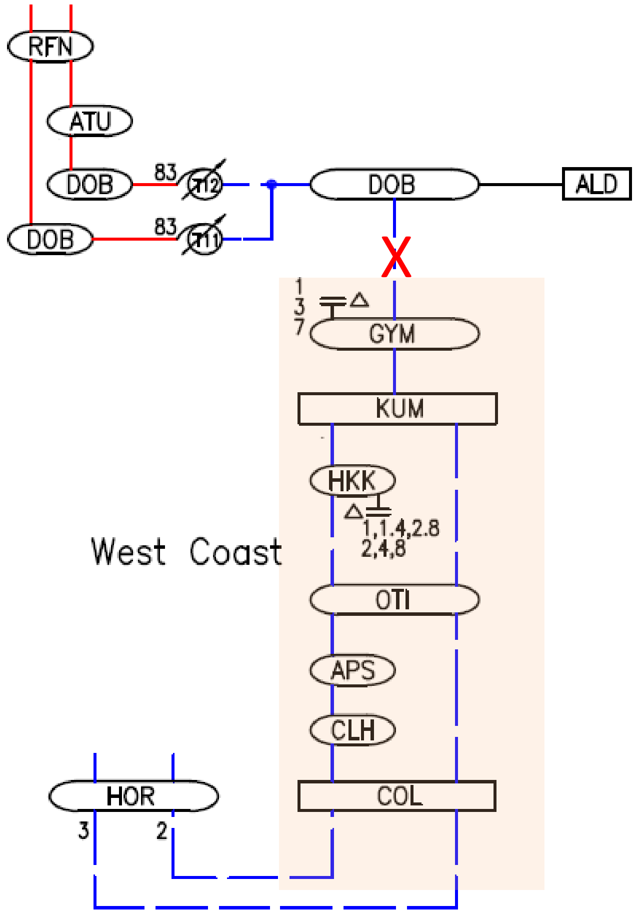
4.31 However, this situation did not last longer than three consecutive trading periods. The high price separation could be explained by the sudden high load in the region and, perhaps, Genesis was caught by surprise.

4.32 Because the load data shows a high likelihood of WKA being pivotal during a RDF_T3 or T4 outage, this region is considered to be potentially at risk of locally net pivotal generation during a RDF_T3 or T4 outage.

### TrustPower on the West Coast

4.33 Historical data show that the Dobson-Kumara single line (DOB_KUM_1) is out of service for 366 hours per year on average. When that Dobson-Kumara single line is out of service there will be a voltage stability issue in West Coast. As a result, a voltage stability constraint is applied to limit the energy imported into the region (shaded area in Figure 20) through the Hororata-Coleridge (HOR-COL) double lines. The limit is variable but is usually around 10MW.

**Figure 20 Single line network diagram of affected region – TrustPower locally net pivotal**



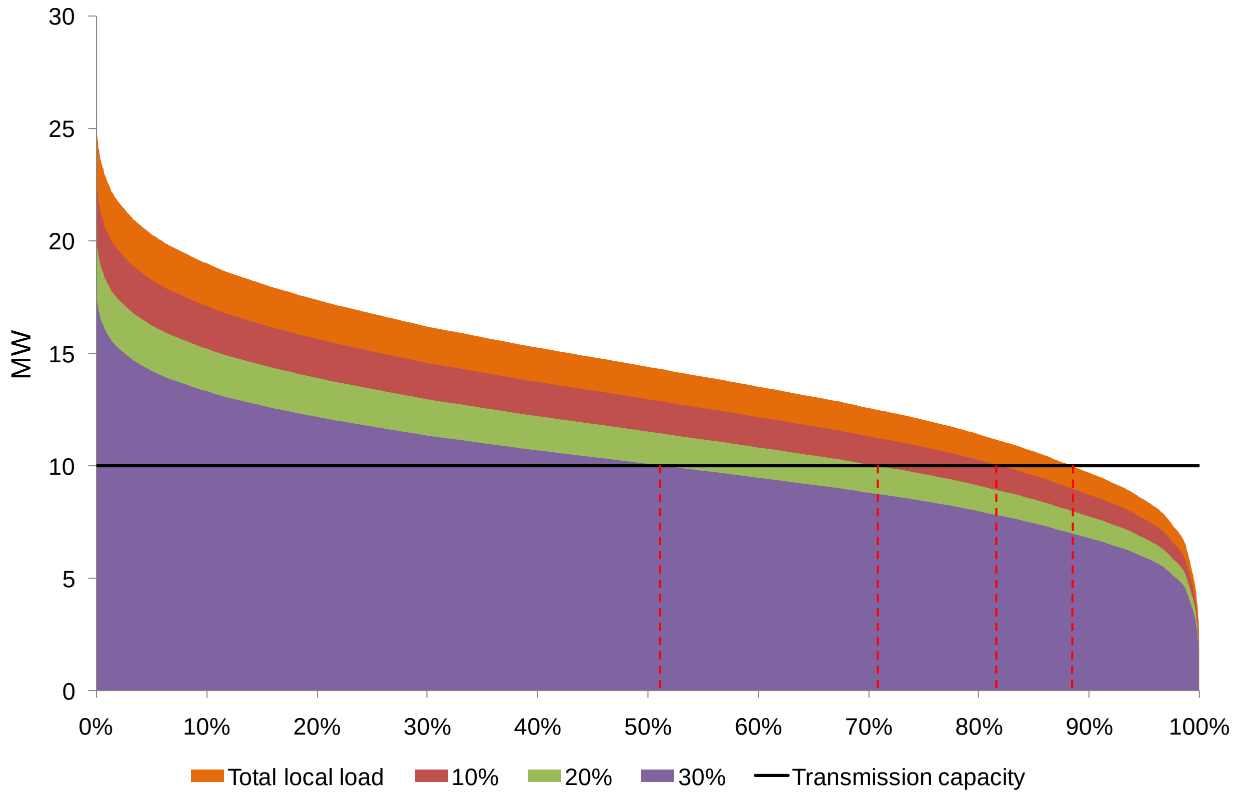

Source: http://www.systemoperator.co.nz/maps-diagrams

4.34 If the total energy demand at Coleridge (COL), Castle Hill (CHL), Arthurs Pass (APS), Otira (OTI), Hokitika (HKK), Kumara (KUM) and Greymouth (GYM) is much higher than 10MW, the remaining demand will be met by generation at Coleridge and Kumara. Because TrustPower is the only owner of both power stations, TrustPower is very likely locally pivotal during this outage. The historical maximum total load in this region was 26.7MW on 3 November 2011 in trading period 17. The historical maximum total load in this region during the outage of DOB_GYM_1 was 25.52MW on 18 November 2009 in trading period 15.

4.35 Figure 21 represents the LDC for Coleridge, Castle Hill, Arthurs Pass, Otira, Hokitika, Kumara and Greymouth from 1 May 2011 to 30 April 2012. Given the voltage stability constraint that limits energy imports into the region to about 10MW, TrustPower is pivotal in the region 88 percent of the time when the Dobson-Kumara transmission line is out of service. TrustPower's net pivotal status in the region depends on its contracted load in the region.

4.36 The 10, 20 and 30 percent areas represent the load in the region excluding TrustPower local contracted load with the assumption that TrustPower's local contracted load equals 10, 20 and 30 percent of total local load respectively. If the local contracted load equalled 10 percent of total load, TrustPower could be net pivotal 82 percent of the time. Similarly, if the local contracted load equalled 20 percent of total load, TrustPower could be net pivotal 71 percent of the time. If the local contracted load was 30 percent of total load, TrustPower could be net pivotal 52 percent of the time.

**Figure 21 Propensity for TrustPower to become net pivotal on the West Coast**




Source: Electricity Authority

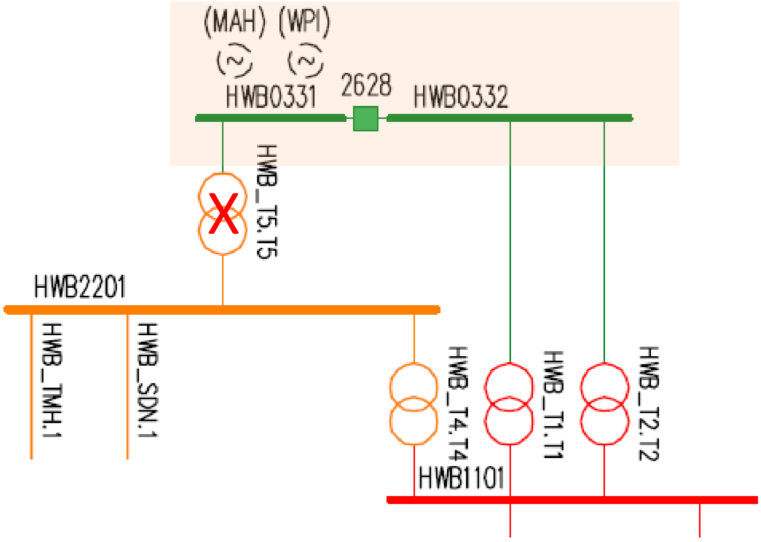
Notes:
1. Data from 1 May 2011 to 30 April 2012.
2. The upper boundary of the 10 percent area line represents the remaining load of the region after excluding TrustPower's contracted load which is assumed to be 10 percent of total load. Similarly for the 20 and 30 percent cases.

4.37 Historical pricing data does not show any significant price separation between Hororata and Coleridge. However, because the load data shows a high likelihood of TrustPower being locally pivotal during a DOB_GYM_1 outage, this region is considered to be potentially exposed to locally net pivotal generation during this outage.

### Waipori at Halfway Bush

4.38 Historical data shows the Halfway Bush transformer T5 (HWB_T5) is out of service for 180 hours per year on average. When HWB_T5 is out of service, circuit breaker 2628 is closed. Local load at Halfway Bush (shaded area in Figure 22) is supplied by TrustPower generation (Waipori hydro station and Mahinerangi wind farm) and through Halfway Bush T1 and T2. The total capacity of HWB_T1 and T2 is 114MW (57MW each).

**Figure 22 Network diagram of affected region – WPI locally net pivotal**




Source: http://www.systemoperator.co.nz/maps-diagrams

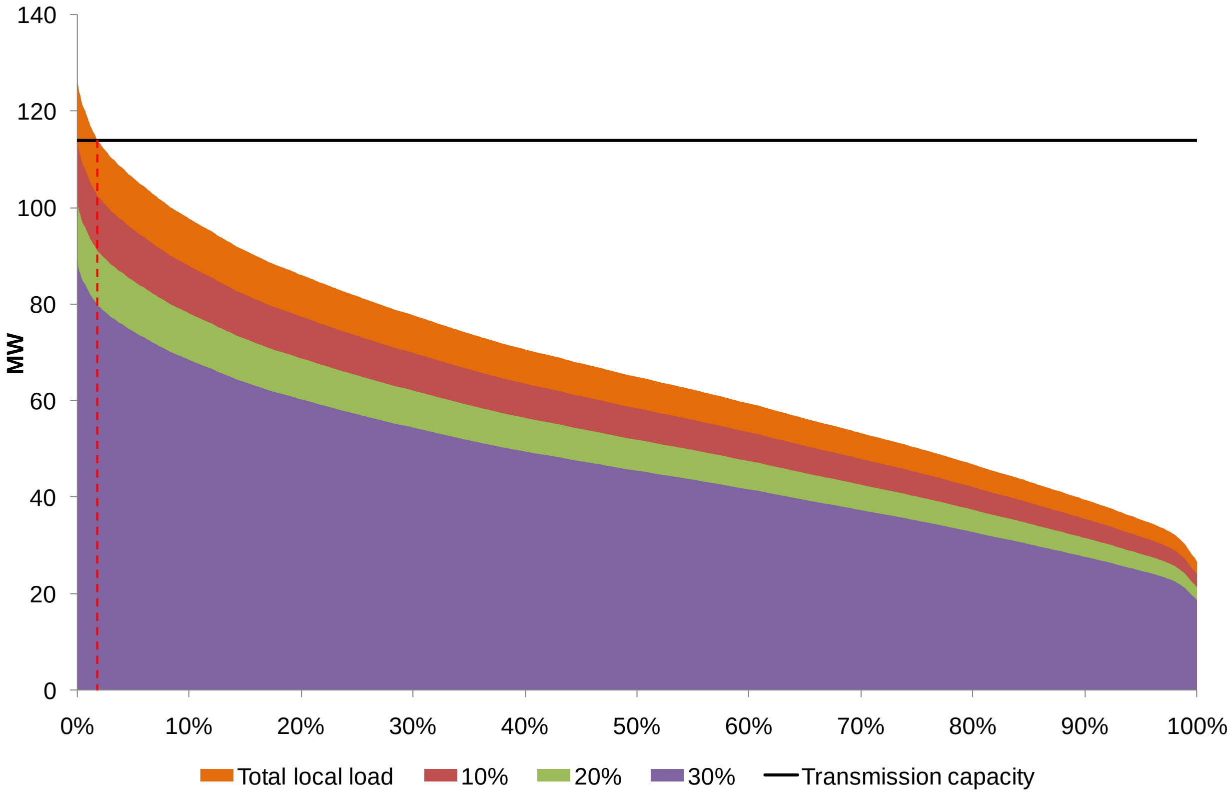
4.39 If the total energy demand at Halfway Bush (HWB0331 and HWB0332) is much higher than 114MW, the remaining demand will be met by the Waipori hydro plant and the Mahinerangi wind farm. Because TrustPower owns both generation facilities it is very likely to be locally pivotal during this outage. The historical maximum total load in this region was 128.9MW on 16 August 2011, during trading period 29.

4.40 Figure 23 represents the LDC for Halfway Bush from 1 May 2011 to 30 April 2012. Given the maximum total capacity of HWB_T1 and T2 is 114MW, TrustPower is pivotal in the region only 1.8 percent of the time if HWB_T5 is out of service. Depending on TrustPower's contracted load in this region, TrustPower can be locally net pivotal.

4.41 The 10, 20 and 30 percent lines represent the load in the region excluding TrustPower's local contracted load with the assumption that TrustPower's local contracted load equals to 10, 20 and 30 percent of total local load respectively. If the local contracted load equalled 10 percent of total load, TrustPower could be net pivotal only 0.05 percent of the time.

4.42 Because of the Mahinerangi wind farm, it is unlikely that TrustPower can take advantage of a net pivotal position. Because of this, there is a low risk of locally net pivotal generation at Halfway Bush when HWB_T5 is out of service.

**Figure 23 Propensity for Halfway Bush to become locally net pivotal**




Source: Electricity Authority

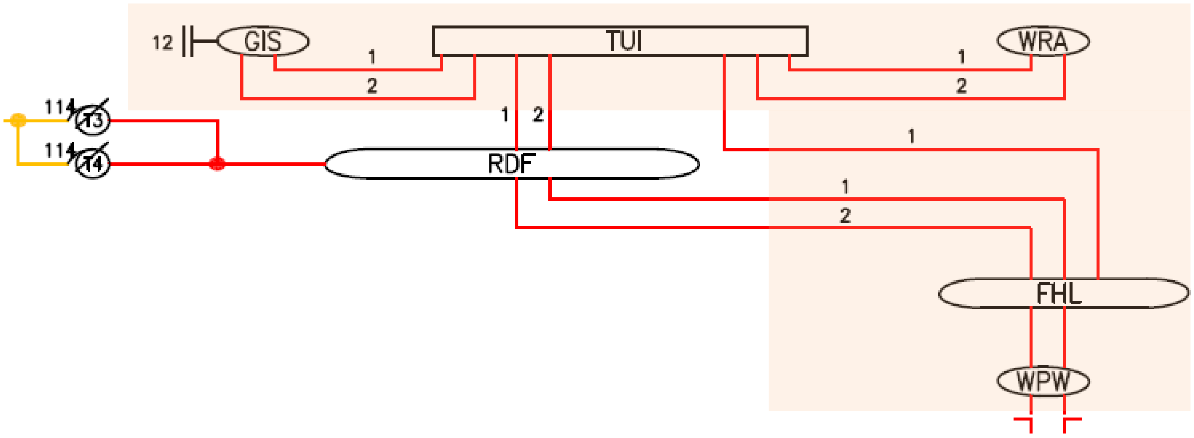
Notes:
1. Data from 1 May 2011 to 30 April 2012.
2. The upper boundary of the 10 percent area line represents the remaining load of the region after excluding TrustPower's contracted load which is assumed to be 10 percent of total load. Similarly for the 20 and 30 percent cases.

## Type III – Net pivotal generation causes spring washer effect

### Waikaremoana power scheme (Waipawa split moves)

4.43 When the Waipawa (WPW) split moves and disconnects WPW from Dannevirke (DVK), WPW load is provided through the WPW-FHL transmission lines. When this happens, more energy will flow through the FHL_RDF transmission lines to supply FHL and WPW. If the load in the region (shaded area in Figure 24) is high and Waikaremoana generation is low, an N-1 security constraint protecting the FHL _RDF transmission lines can bind and cause a spring washer effect. If this occurs, the energy price at FHL (and WPW) will be approximately twice the energy price at TUI less the price at RDF.

Figure 24 Single line network diagram of affected region – WPW split moves




Source: [http://www.systemoperator.co.nz/maps-diagrams](http://www.systemoperator.co.nz/maps-diagrams)

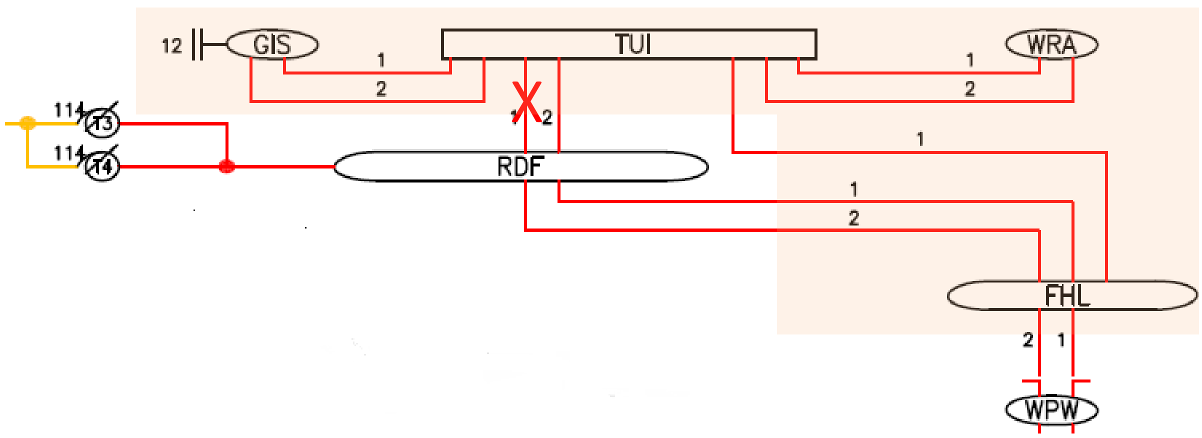
4.44 Let *a*MW denote the total load at TUI, GIS and WRA (*A*); *b*MW the total load at FHL and WPW (*B*); and *x*MW the minimum WKA generation injecting into the grid at TUI to avoid the constraint binding. If *a* and *b* are low, *x* can be less than or equal to zero. This means that WKA would not be pivotal in this region.

4.45 Let $\theta^A$ and $\theta^B$ denote the average load share (percent) of WKA in *A* and *B*, respectively. Let $P^{TUI}$ and $P^{RDF}$ denote the marginal price at TUI and RDF, respectively where $P^{TUI} >> P^{RDF}$. If $xP^{TUI} > (\theta^A aP^{TUI} + 2\theta^B bP^{TUI})$ or $x > (\theta^A a + 2\theta^B b)$, WKA is net pivotal.

### Waikaremoana power scheme (RDF_TUI_1 or RDF_TUI_2 outage)

4.46 When the RDF_TUI_1 or RDF_TUI_2 transmission line is out of service and Waikaremoana generation is low, more energy will flow through the FHL_RDF transmission lines to supply GIS, WRA and FHL. If the load in the region (shaded area in Figure 25) is high and Waikaremoana generation is low, an N-1 security constraint protecting the FHL_RDF transmission lines can bind and cause a spring washer effect. If this occurs, the energy price at FHL will be approximately equal to 1.5 times the energy price at TUI less the price at RDF.

Figure 25 Single line network diagram of affected region – RDF_TUI_1 or 2 outage




Source: [http://www.systemoperator.co.nz/maps-diagrams](http://www.systemoperator.co.nz/maps-diagrams)

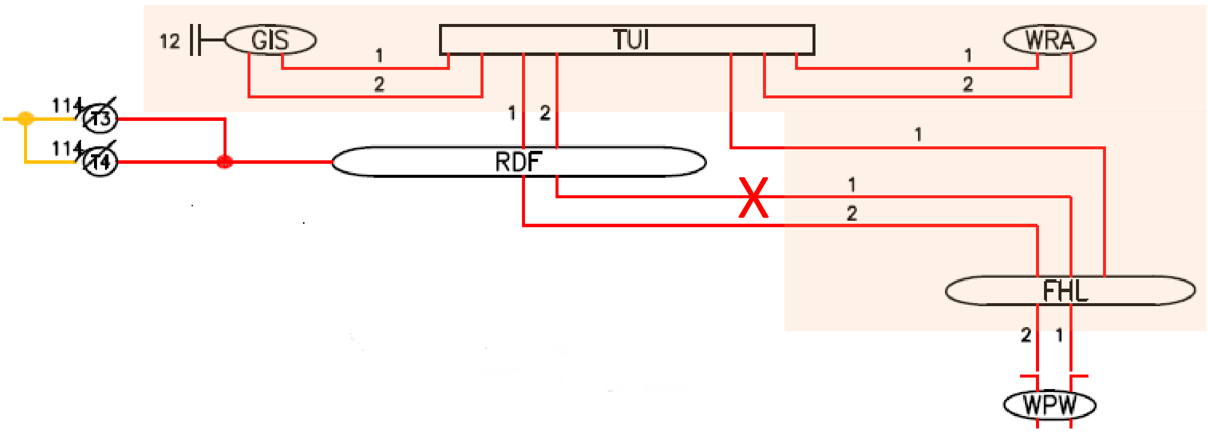
4.47 Now, let *a*MW denote the total load at TUI, GIS and WRA (*A*), *b*MW is the total load at FHL (*B*), and *x*MW is the minimum WKA generation injecting into the grid at TUI to avoid the constraint binding. If *a* and *b* are low, *x* can be less than or equal to zero. This means that WKA is not pivotal in this region.

4.48 Let $\theta^A$ and $\theta^B$ denote the average load share (percent) of WKA in *A* and *B*, respectively. Let $P^{TUI}$ and $P^{RDF}$ denote the marginal price at TUI and RDF, respectively where $P^{TUI} >> P^{RDF}$. If $x*P^{TUI} > (\theta^A aP^{TUI} + 1.5\theta^B bP^{TUI})$ or $x > (\theta^A a + 1.5\theta^B b)$, WKA is net pivotal.

### Waikaremoana power scheme (FHL_RDF_1 or FHL_RDF _2 outage)

4.49 When the FHL_RDF_1 or FHL_RDF_2 transmission line is out of service and Waikaremoana generation is low, more energy will flow through the FHL_RDF transmission lines to supply GIS, WRA and FHL. If the load in the region (shaded area in Figure 26) is high and Waikaremoana generation is low, an N-1 security constraint protecting the FHL_RDF transmission lines can bind and cause a spring washer effect. If this occurs, the energy price at FHL will be approximately equal to 1.5 times the energy price at TUI less the price at RDF.

**Figure 26 Single line network diagram of affected region – FHL_RDF_1 or 2 outage**




Source: http://www.systemoperator.co.nz/maps-diagrams

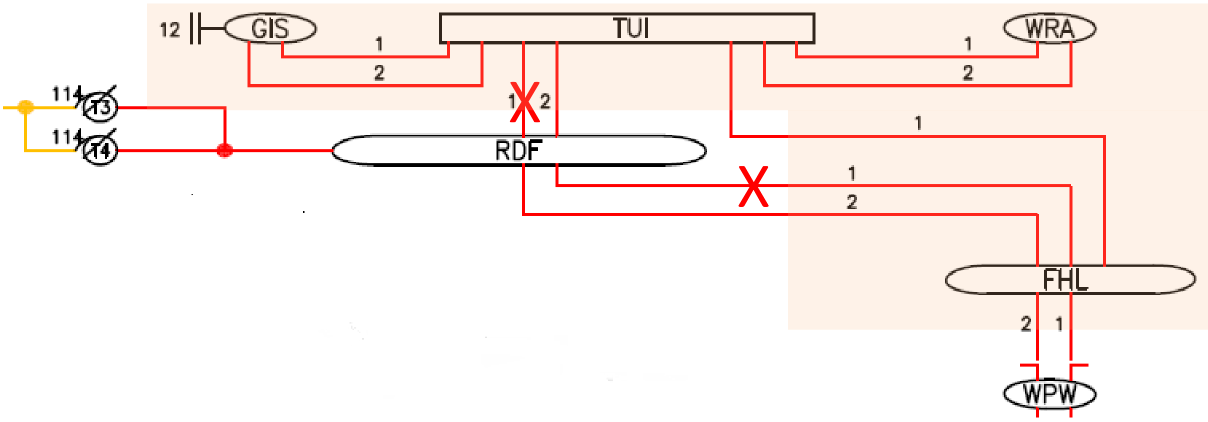
4.50 Now, let *a*MW denote the total load at TUI, GIS and WRA (*A*), *b*MW is the total load at FHL (*B*), and *x*MW is the minimum WKA generation injecting into the grid at TUI to avoid the constraint binding. If *a* and *b* are low, *x* can be less than or equal to zero. This means that WKA is not pivotal in this region.

4.51 Let $\theta^A$ and $\theta^B$ denote the average load share (percent) of WKA in *A* and *B*, respectively. Let $P^{TUI}$ and $P^{RDF}$ denote the marginal price at TUI and RDF, respectively where $P^{TUI} >> P^{RDF}$. If $x*P^{TUI} > (\theta^A aP^{TUI} + 1.5\theta^B bP^{TUI})$ or $x > (\theta^A a + 1.5\theta^B b)$, WKA is net pivotal.

### Waikaremoana power scheme (FHL_RDF_1 or 2 and RDF_TUI_1 or 2 outage)

4.52 When the RDF_FHL_1 or 2 and FHL_RDF_1 or 2 are out of service and Waikaremoana generation is low, more energy will flow through the remaining in-service RDF_TUI and FHL_RDF transmission lines to supply GIS, WRA and FHL. If the load in the region (shaded area in Figure 27) is high and Waikaremoana generation is low, an N-1 security constraint protecting the FHL_RDF transmission lines can bind and cause a piece separation between RDF and the rest of the East Coast. If this occurs, the energy price at GIS, FHL and WRA will be approximately equal to the energy price at TUI.

**Figure 27 Single line network diagram of affected region – FHL_RDF_1 or 2 and RDF_TUI_1 or 2 outage**



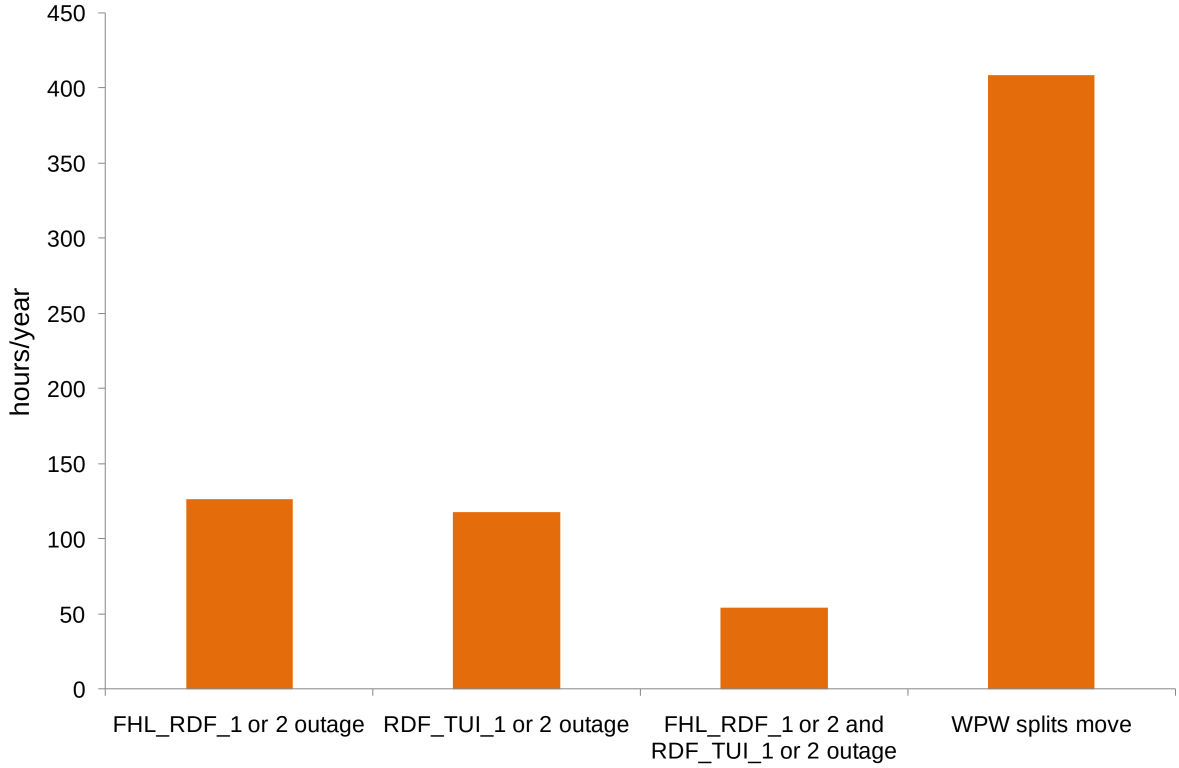

Source: [http://www.systemoperator.co.nz/maps-diagrams](http://www.systemoperator.co.nz/maps-diagrams)

4.53 Now, let *a*MW denote the total load at TUI, GIS and WRA (*A*), *b*MW is the total load at FHL (*B*), and *x*MW is the minimum WKA generation injecting into the grid at TUI to avoid the constraint binding. If *a* and *b* are low, *x* can be less than or equal to zero. This means that WKA is not pivotal in this region.

4.54 Let $\theta^A$ and $\theta^B$ denote the average load share (percent) of WKA in *A* and *B*, respectively. Let $P^{TUI}$ and $P^{RDF}$ denote the marginal price at TUI and RDF, respectively where $P^{TUI} >> P^{RDF}$. If $x * P^{TUI} > (\theta^A a P^{TUI} + \theta^B b P^{TUI})$ or $x > (\theta^A a + \theta^B b)$, WKA is net pivotal.

4.55 Figure 28 shows the average number of hours per year of different outages and grid reconfigurations in the East Coast. This figure excludes the RDF_T3 and T4 outages.

**Figure 28 Frequency of transmission outages or grid reconfigurations in the East Coast**

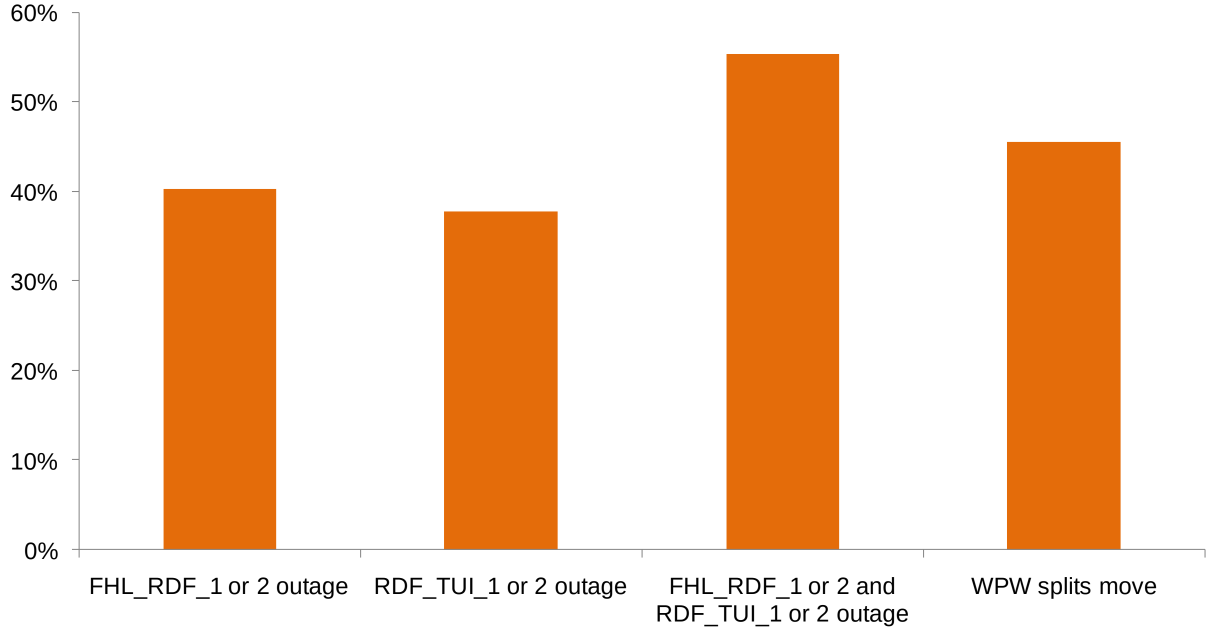



Source: Electricity Authority

Note: Based on historical data from 1 May 2004 to 30 April 2012.

4.56 Simulations for each outage/grid reconfiguration scenario using load data from 1 May 2011 to 30 April 2012 show that WKA could be pivotal 40 percent of the time (daytime only) if FHL_RDF_1 or 2 was out of service for the whole year and the maximum pivotal amount would be 41MW. This means that in the worst case, WKA would have to generate at least 41MW to avoid the constraint binding. Figure 29 and Figure 30 below summarise the simulation results for all four scenarios of outage/grid reconfiguration.

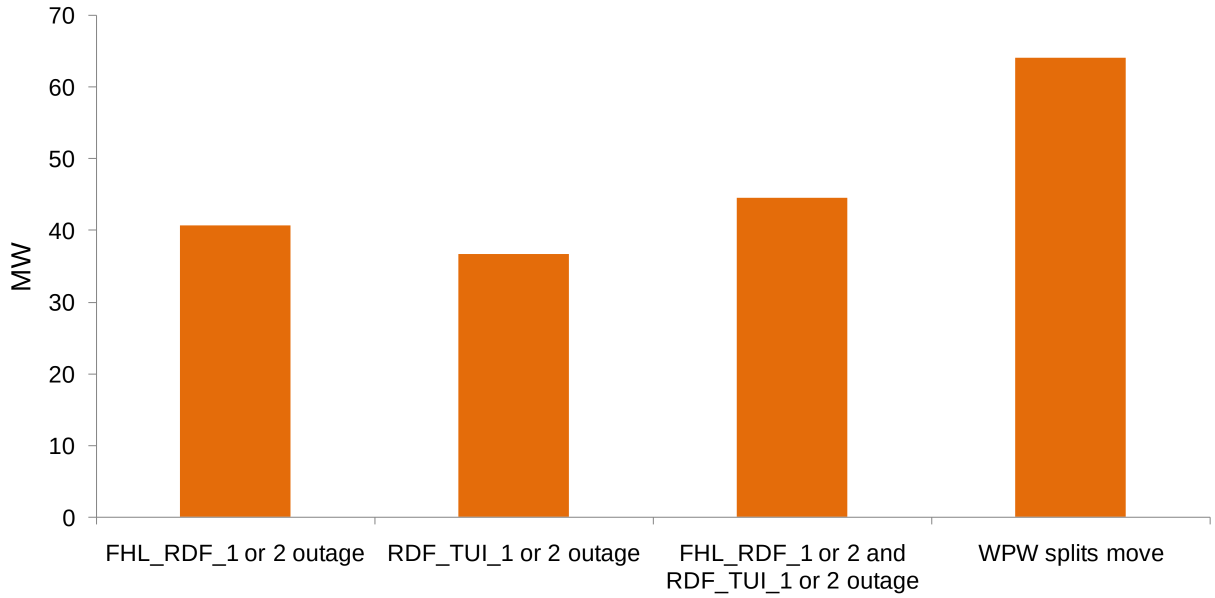
**Figure 29 Probability of WKA being locally pivotal under different outage scenarios**




Source: Electricity Authority

Notes:
1. Assume that each outage or grid reconfiguration scenario is applied for the whole year.
2. Load data from 1 May 2011 to 30 April 2012 is used for the simulations.
3. Simulations are run for daytime only (TP 15 – TP 42).

**Figure 30 Maximum pivotal quantity at Waikaremoana power scheme.**




Source: Electricity Authority

Notes:
1. Pivotal quantity is the minimum amount that WKA needs to generate to avoid the constraint binding.
2. Assume that each outage or grid reconfiguration scenario is applied for the whole year.
3. Load data from 1 May 2011 to 30 April 2012 is used for the simulations.

## Summary

4.57 All the locally net pivotal generation risks described above are estimated based on recent data for load, generation, and grid configuration. If one or more of these factors change significantly the risk within a region can also change. Table 1 below summarises the potential amount of load exposed to locally net pivotal generation.

**Table 1 Locally net pivotal generation exposure**

| Outage(s) | Frequency | Probability | Substations involved | Average Total Load | Exposure |
|---|---|---|---|---|---|
| ABY_TIM_1 | 43 hrs/year | 100% | ABY, TKA | 4.35 MW | 187 MWh/year |
| ABY_TKA_1 | 72 hrs/year | 100% | TKA | 1.67 MW | 120 MWh/year |
| STK_T3 | 30 hrs/year | 100% | MOT, MPI, UTK | 17.5 MW | 525 MWh/year |
| HAM_KPO_1 or 2 | 128 hrs/year | 47% | MOT, MPI, UTK | 82 MW | 4,944 MWh/year |
| KIN thermal Gen | 600 hrs/year | 90% | KIN, LFD | 85 MW | 45,900 MWh/year |
| RDF_T3 or T4 | 140 hrs/year | 14% | GIS,TUI,WRA, RDF,FHL | 133 MW | 2,615 MWh/year |
| DOB_GYM_1 | 336 hrs/year | 88% | GYM,KUM,HKK, OTI,APS,CLH,COL | 15 MW | 4,494 MWh/year |
| FHL_RDF_1 or 2 | 127 hrs/year | 40% | GIS,TUI,WRA,FHL | 73.3 MW | 3,750 MWh/year |
| RDF_TUI_1 or 2 | 118 hrs/year | 38% | GIS,TUI,WRA,FHL | 73.4 MW | 3,279 MWh/year |
| RDF_TUI_1 or 2 and FHL_RDF_1 or 2 | 54 hrs/year | 55% | GIS,TUI, WRA,FHL | 71.4 MW | 2,147 MWh/year |
| WPW Split moves | 409 hrs/year | 46% | GIS,TUI,WRA, FHL,WPW | 88 MW | 16,356 MWh/year |
| **Total exposure** | | | | | **84 GWh/year** |

Source: Electricity Authority

Notes:
- Outage frequency is estimated based on historical outage data.
- Probability means the likelihood of locally pivotal generation.
- Average total load means average of total load of all trading periods in which the locally pivotal generation occurs.
- Exposure amount = Frequency x Probability x Average total load.

4.58 There are many ways to manage or mitigate the locally net pivotal generation risk. However, not all of the remedies can be applied to all at-risk regions. In some regions, the risk can be managed by grid configuration (close/open a split). In other regions, the risk can be managed by shifting load out of the risky region or by increasing generation output of pivotal generator through hedging contracts . Some methods are practical in one region but not practical in others.

4.59 Net pivotal generation behaviour similar to that observed at the Cobb and Tekapo A hydro plants is not limited to small regions but can be more widespread and include larger regions and could potentially occur on an island or national basis. The Commerce Commission analysed this type of behaviour and such analysis is beyond the scope of this report.[9] Rather, this report concentrates

[9] Commerce Commission's 2009 Electricity Investigation Report by Professor Wolak.

on smaller regions where there is only one generator or a group of generators with the same owner that is able to increase the spot price during an outage.

4.60 The following section discusses the impact of the behaviour of net pivotal generators on the efficiency and competition of the New Zealand electricity market.

# 5 Implications of net pivotal generation for efficiency and competition

5.1 The events discussed above at Tekapo A on 20-22 February 2012 and at Cobb on 5 April 2012 highlight an axiomatic reality of all electricity markets. That is, from time-to-time and generally for quite short durations, a generator will be net pivotal and is able to set the price at a level of its choosing. Planned outages of transmission equipment are often the cause of net pivotal generation situations but they are not the only cause. Planned generation outages, unplanned generation or transmission outages, or exceptionally high and unanticipated demand may all lead to situations of net pivotal generation.

5.2 The key issue raised by net pivotal generation events is not that the spot market price may be elevated to very high levels. Rather it is whether such prices are determined efficiently and are therefore pro-competitive.

5.3 The Authority's position on high prices per se is clear from its past decisions:

(a) a price floor of $10,000/MWh has been codified for emergency load-shedding situations;

(b) when the Authority was responsible for the Whirinaki reserve plant, the offer price was set at $5,000/MWh; and

(c) the Authority set Genesis' offer prices to $3,000/MWh to remedy the undesirable trading situation that the Authority determined to have occurred on 26 March 2011.

5.4 High prices in (a) and (b) are efficient because they reward investment in last-resort plant and demand-response capability – investments that often sit unused for much of the year. When supply is insufficient to meet demand, an efficient pricing outcome is characterised by prices increasing to the value the marginal consumer places on forgoing some consumption. At this point, the price reflects opportunity cost and would ordinarily be well above the short-run marginal cost of supply.

5.5 But net pivotal generation situations are not supply shortage situations. There is always plant on hand to meet demand during net pivotal generation situations; it's just that the operator of the plant chooses to offer it to the market at a high price.

5.6 A generator is pivotal when some of its output is required to serve demand. By definition then, a pivotal generator has the *ability* to set the market price. However, ability to set the price may not translate into an incentive to set the price at a high level. A generator has an *incentive* to set the price at a level of its choosing when it is net pivotal. That is, its minimum required generation output exceeds its own retail load and hedge obligations in the region to which the net pivotal generation situation applies, taking into account other pricing factors.

5.7 There are two main efficiency-reducing impacts that may follow from the uncompetitive behaviour of generators finding themselves to be net pivotal:

(a) short-term or allocative efficiency is reduced because society's resources are used in a suboptimal way, e.g. load is shed when its opportunity cost is greater than the short-run marginal cost (SRMC) of the plant that could have satisfied it; and

(b) long-term or dynamic efficiency is reduced when high prices encourage inefficient investment or, conversely, discourage efficient investment. For example, if the net pivotal generator sets a price that exceeds its own long-run marginal cost (LRMC), consumers may be needlessly incentivised to relocate to some other region. Retailers may exit the area and retail competition may reduce. Similarly, the incentives for investment in transmission or transmission alternatives are biased in favour of unnecessary investments.

5.8 The magnitude of the loss of efficiency is difficult to estimate, but is extremely small in the short term. In the short term, ie during the event, load is primarily on fixed-price contracts, and so has no incentive or financial imperative to respond. For example in the Cobb region, industrial load at Takaka did not respond to $3,000/MWh prices as it was not exposed to them at that point in time. In the short term, the impact of the high prices is to cause a wealth transfer.

5.9 Over the longer term, retailers exposed to high prices would try to pass on the risk of that exposure to retail tariffs, and this could lead to some demand response that would be inefficient. However any such increase in tariffs would not fully recompense a retailer for the uncapped risk to which they may perceive themselves being exposed. A more likely outcome is simply the concentration of retailer market share by the pivotal generator, and consequent non-competitive retail pricing.

5.10 A further long-term effect might be retail concentration in all regions where a local generator is likely to be net pivotal due to some as yet unforeseen and innovative circumstance that causes net pivotal status. This is really a perception issue that might arise if extreme pricing during net pivotal situations became more common. Retailers would be unsure of where they might be struck next and there could consequently be a substantial reduction in retail competition in rural areas, or areas where grid capacity alone can not serve local load.

5.11 We might estimate that in this case retail prices in East Cape, Tasman, West Coast and North Isthmus were 10 percent higher than elsewhere, and that demand elasticity is -0.3. Then the dead weight loss per year equals ½ x $\Delta$Q x $\Delta$P = ½ x 6286(GWh) x 3(percent) x 83.15($/MWh) x 1000 x 10(percent)[10] = $0.78 million ≈ $7.8 million on a net present value basis.

5.12 Another response to inefficient pricing and risk that is unable to be hedged or limited could be the installation of diesel generation in locations that are not efficient. In a dynamically efficient industry, we might expect last-resort firming plant to locate where it minimises losses, because losses are highest at peak times, and such plant defers investment in transmission or distribution.

5.13 Assuming 60MW peak demand growth per annum, a LRMC of transmission equal to $200,000/MW, and that 10 percent of diesel generation is misallocated to manage price risk caused by locally net pivotal generation, an order of magnitude estimate for this aspect of the inefficiency has a net present value of $12 million (60MW per annum times 0.1 times $200,000/MW= $1.2 million per annum ≈ $12 million NPV). This is the present value of transmission that could have been avoided by better placement of last resort generation.

5.14 It might be argued that the 9MW of diesel generation installed north of Auckland by TrustPower is an example of this type of inefficiency. This new diesel generation does not defer any major grid investments as they are already committed.

5.15 These estimates serve to show that the present value costs of inefficient pricing associated with locally net pivotal generation could be in the tens of millions of dollars if such practices were to become prevalent or perceived to be so.

5.16 In other words, the reliability of price as an efficient resource coordinating and investment signalling mechanism breaks down when net pivotal generators are able to set prices without competitive restraint.

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10 6286(GWh) is total one year load of East Cape, Tasman, West Coast and North Isthmus. The load weighted average price of these four regions is $83.15 /MWh.

# 6 Potential remedies

6.1 A large number of remedies might conceivably be proposed for dealing with net pivotal generation situations. However, what is more difficult, is ensuring that they work in practice and don't give rise to a raft of unintended consequences.

6.2 The ideal remedy would enable parties to manage the risks they face on a commercial basis rather than:

(a) passing those risks through to parties less able or entirely unable to manage them; or

(b) avoiding the risks altogether by not participating in the affected markets, leading to a lessening of competition.

6.3 For a remedy to endure and be effective, it will need to adhere to a minimal set of design principles. Any proposed remedy must:

(a) be able to be described and understood by participants;

(b) ensure that the party best able to fix (or prevent) net pivotal situations is incentivised to do so; and

(c) lead to efficient and predictable outcomes across a broad range of net pivotal generation manifestations.

6.4 These design principles might be more succinctly characterised as: simple and explicit, those that can do something about it should; and for the long-term benefit of consumers.

6.5 When thinking about the design of a resolution to net pivotal situations, it is useful to break down the thinking into one of the following three facets:

(a) define the affected market;

(b) can a net pivotal generation event be avoided?

(c) if it can't be avoided, how best can the interests of consumers be protected?

## Defining the affected market

6.6 Every market has three fundamental dimensions – time, space, and form. Designing a resolution that is limited to the time periods covered by the net pivotal situation ought to be straightforward enough.

6.7 Similarly, it is relatively uncomplicated to determine the space, or geographic boundaries, that apply to any given net pivotal situation. In the two cases analysed earlier in this report, the affected market was a region spanning an area much less than an island. It is predictable that net pivotal generation situations will apply to relatively localised areas because as the market area gets larger, it is more likely that naturally occurring competitive pressures will act to restrain generator behaviour. In any case, the New Zealand electricity sector already has an island-based scarcity pricing regime designed to assist its energy-only market to deliver sufficient generating capacity[11]. Hence, it is desirable that a resolution to net pivotal situations does not interfere with the scarcity pricing regime.

6.8 The form or product dimension is more difficult to define precisely because net pivotal situations easily migrate from one product form to another. The physical or spot market and the forward market is a case in point.

[11] Scarcity pricing will come into effect in June 2013

6.9 When a generator is net pivotal in a local region it has substantial market power and a strong incentive to raise spot prices in the region. In order to avoid the exposure to high spot prices load customers in the region can, in theory, seek out a supply contract (a hedge) during the period of locally net pivotal generation. However, it is naive to imagine that the net pivotal generator would be willing to offer such a contract at a price that yields a return any lower than would be attained from the spot market with prices it set itself by virtue of being net pivotal.

6.10 Precisely this behaviour was observed during the Tekapo A and Cobb events. In these two cases the net pivotal generator either declined to offer a hedge or offered one at the same price as the indicative spot price. In other words, by definition, the net pivotal generator is the 'only game in town' and can choose to exercise its market power in either the spot market or the derived forward market. Or it can spread its influence over both and trade off the profit from the sale of any hedge contract with the foregone profit it could have earned in the spot market.

6.11 In many instances of Type II and III locally net pivotal generation a relatively small hedge contract, equal to just a small portion of load in the net pivotal region, is all that's needed to discourage the net pivotal generator from causing the transmission constraint to bind, which in turn enables the spot price to be elevated. However, in the case of Type I locally net pivotal generation, it is much more difficult, if not impossible, for a local load customer to procure a hedge contract to cover most (if not all) of its load to avoid being exposed to high spot prices.

6.12 In any event hedge contracts are unable to help local load customers to avoid the consequences of locally net pivotal generation. Instead of paying high spot prices the load customer pays a high price for the hedge contract. The use of hedge contracts to discourage the net pivotal generator from exercising its market power in the spot market may be effective once or twice. But in a repeated game, a profit maximising generator will eventually learn how to play. At some point the term of the hedge contract will expire and require renewal. At that point the profit maximising generator will likely have figured out how to arbitrage its strong position across the spot and forward markets.

### Credible alternatives to spot and future market forms

6.13 Another risk mitigation option for a local consumer would be to arrange alternative physical supply or demand response during the period that a local generator was net pivotal. In some situations this may be possible if there is adequate forewarning to make arrangements, and the quantity of alternative supply required is small. For example, in the case of the Tekapo A Type I situation, it is not entirely clear that Opuha generation is excluded from acting as an alternative to Tekapo A. Conflicting information regarding the rough running range for Tekapo A was provided to the Authority, and it seems that if parties involved were suitably motivated, there could be alternative generation.

6.14 The existence of credible alternative physical arrangements ought to act as a limit on the ability of a net pivotal generator to set high prices in the wholesale or contract market. Therefore, the types of alternative arrangement that are available are critical to mitigation strategies, and this in turn relates to the market dimension of form.

6.15 Market arrangements or mitigations developed by means of pricing in the wholesale market are ultimately grounded in the credibility of alternative supply or demand response. Possibilities here could be contracts with other local generation, investment in new peaking plant, or the short-term installation of mobile diesel generators. The threat of these alternative arrangements being undertaken ought to enable efficient pricing for contracts with the locally pivotal generator – provided the threat is credible.

6.16 The threat of bringing in alternative generation or demand response during negotiations for contract cover will often not be credible. For example, in the Cobb situation, it is simply not feasible to bring in 23MW of diesel generation for the period of the outage.

6.17 Other parties do have credible alternatives beyond those normally associated with the wholesale market. If the grid owner or system operator were negotiating with the locally net pivotal generator, they may arguably have access to alternative arrangements that would severely restrict the ability of the local generator to set a high price. Options available to the grid owner or system operator might include:

(a) bring in a portable substation during a transformer outage;

(b) modify a planned maintenance action to avoid the need for the outage;

(c) defer the maintenance;

(d) temporarily reconfigure the grid; or

(e) dynamically rate the transmission assets to increase capacity.

6.18 In many cases, highly credible alternatives that are not available to local consumers or retailers will exist for the grid owner or the system operator. Therefore, in considering mitigations or market design changes, access to the full suite of physical alternatives will be critical in mitigating the ability of a locally net pivotal generator to set high prices.

## Can net pivotal generation events be avoided?

6.19 It is likely that resolutions that minimise the frequency of, or avoid entirely, net pivotal generation events are associated with lower costs and regulatory impacts. If so, they should be preferred to more intrusive restraint mechanisms. Improved processes and incentive alignment concerning outage planning are a case in point.

6.20 Under current arrangements, market prices play little role in Transpower's outage planning; the focus is more directed at ensuring security of supply. So long as there is enough energy supply in a region, an outage can go ahead. Because the cost of the alternative or additional generation required to enable an outage to proceed is not charged to Transpower, it has no incentive to reduce costs associated with outages. A more explicit regime that required Transpower to bear some or all of the outage costs may alter decisions made by Transpower.

6.21 Many locally net pivotal generation situations can be avoided (Type II and III) or diminished (all types) if the transmission outage occurred during the low demand period of the year, or even during weekends or at night. If the system operator was incentivised differently, the resulting prices may feature more prominently in its outage planning processes. As a result, some locally net pivotal generation situations could be avoided, reducing costs for load customers.

## Protecting the interests of consumers

6.22 If all else fails and a situation of net pivotal generation is unavoidable, and the generator in question does not exercise restraint, consideration could be given to imposing a price outcome that restores confidence in the market and has the effect of betterment of the long-term benefit of consumers.

## Five illustrative remedies

6.23 In this section, five potential remedies aimed at addressing net pivotal situations are outlined:

(a) net pivotal declaration;

(b) price or offer by fiat;

(c) the branch buffer;

(d) the contract grid; and

(e) the contract grid with limited side payment.

6.24 These five are not intended to be an exhaustive list of options. Rather, they are sufficient to illustrate how any proposed remedies might mitigate the ability of a net pivotal generator to set high prices. The options address net pivotal situations in several dimensions – either allowing more time for a party exposed to the price risk to present a credible alternative arrangement to the net pivotal generator, or changing the incidence of the high price risk to a party better able to threaten a wider portfolio of alternative arrangements, or by socialising the price risk so as to promote retail competition in the affected area.

### Net pivotal declaration

6.25 The rationale behind this proposal is that an early gate closure for net pivotal generators, ie earlier than the usual two hours, would give other parties opportunities to arrange demand reduction and/or alternative emergency generation.

6.26 In the event of any changes in grid configuration due to a planned outage of transmission lines or generation, the Authority could declare that, under the assumption demand is as forecast and no temporary generation is connected, a generator will be net pivotal. Alternatively, a generator can self-declare that it expects to be net pivotal. The declared net pivotal status could be publicised as soon as practicable.

6.27 For a generator that has been declared net pivotal, the offer window would close 36 hours prior to the start of a trading period or one hour after the generator has been declared net pivotal, whichever is the earlier, instead of the normal two hours. The normal window closure would apply to all other generators.

6.28 A generator declared net pivotal by the Authority would be allowed to increase the volume it offers after the window closes, but must obey the rules for interruptible load and offer any additional volume at $0.01/MWh. This would enable the generator to adjust its net position as information on its retail commitment firms up nearer to real time. Because it is net pivotal, the additional volume at the low price would not affect the indicative or ultimate final price.

6.29 A generator that self-declares it will be net pivotal would be allowed to increase the volume it offers after the window closes, but could not offer the additional volume at more than its LRMC. This would enable the generator to track its supply curve.

6.30 The Authority, or any other market participant, would be able to challenge that a self-declared net pivotal generator's offer is above the generator's LRMC. If the challenge were upheld, the generator's offer for the additional volume would be reset to $0.01/MWh. If the challenge was from a third-party, and the challenge was not upheld, the third party would have to pay a penalty (eg one percent of the generator's revenue during the time when it offered under the LRMC provision) to the self-declared net pivotal generator.

6.31 If a generator that has been declared net pivotal by the Authority alters its offers inside the window in other ways than permitted under 6.8 and 6.9 above, either it would establish that it was not net pivotal or that it altered its offers for reasons that are bona fide under the current provisions in the Code for altering offers inside the window.

### Price or offer by fiat

6.32 When a generator is locally net pivotal, the usual model-based method of determining prices would be usurped with an administratively determined price at all nodes in the region of locally net pivotal generation. The remedy might reset prices after the fact or, more preferably, ahead of real time so that the prices are indicated to all participants before final production and consumption decisions are taken. In the case of a pre-dispatch remedy, it might be offers rather than prices that would be subject to administrative or regulatory intervention.

6.33 The intention of the price cap (or offer cap) would be to limit the price risk that local load customers would be exposed to under locally net pivotal generation situations. The price cap would be applied for the whole region which is under the effect of locally net pivotal generation. The offer cap would be applied only for the net pivotal generator.

6.34 In the case of an offer cap, the final pricing schedule would be rerun with the offer cap applied for the net pivotal generator and the offer cap prices would be applied for the locally net pivotal generation region.

6.35 The price cap could be equal to an island reference spot price multiplied by a net pivotal pricing factor (greater than one) or equal to an average price of the preceding period (week or month), or equal to the LRMC of the net pivotal generator in the region.

### Branch buffer

6.36 The option of capping locational risk in the wholesale market would be implemented by a modification to the scheduling pricing and dispatch model used to calculate final prices, upon which the wholesale electricity market is settled. A ‘branch buffer’ resource would be added to (potentially) every branch in the model. This is a resource (or a capacity amount) the model can use to violate a branch constraint at some specified cost.

6.37 For example, if a branch was constrained to its transfer limit, with high prices on the receiving end and low prices on the sending end, the branch buffer would enable the model to schedule a greater flow on the branch than its physical limit allowed, but at a cost of say $200/MWh. With the branch buffer invoked, the receiving end price could be no higher than $200/MWh more than the price at the sending end.

6.38 In utilising the branch buffer, the model would have determined that it was cheaper to violate the branch limit at the given price, in order to schedule more low priced generation on the sending end, and probably none of the high priced generation at the receiving end. The branch buffer would have the effect of ensuring that no two adjacent nodes differed in price by more than a pre-set branch buffer price. Sending end prices would be higher as the sending end supply stack would be ascended, but receiving end prices would be lower.

6.39 The transmission branch buffer concept is intended to reduce the locational price separation which can currently exist in the nodal electricity market design.

6.40 In applying the branch buffer concept to address inefficiently high prices due to net pivotal generation, it is unlikely that all branches in the pricing model would have the additional capacity resource applied. The scope of the buffer application would probably be something less than an entire island and less than the entire grid in each island. For example, the HVDC link would be excluded and, quite possibly, key links into major load centres would be excluded as well.

6.41 One of the implications of the branch buffer approach is there would be an increase in constrained-on payments. This increase would be due to actual branch limits and topology being used during dispatch. But during the determination of final prices, branch limits can be exceeded.

This mismatch could result in resources being used during dispatch that are not scheduled in the calculation of final prices.

### Contract grid[12]

6.42 The concept of a contract grid would be to calculate final pricing based on an expected grid (the contracted grid), not the actual available physical grid. The actual available grid would be used for dispatch. The discrepancy between the dispatch and final pricing schedules would then be dealt with via constrained-on payments to generators dispatched at an offer price less than the wholesale market final price.

6.43 The constrained-on cost would be allocated to load customers or to Transpower. Allocating the constrained-on payments to Transpower would motivate it to contract with the locally net pivotal generator as a means of managing Transpower's exposure to constrained-on costs. This would effectively transfer the incidence of the high prices from the market to Transpower, who may then threaten the net pivotal generator with a suite of alternative arrangements not accessible to local retailers or consumers.

6.44 As with the branch buffer idea, the contract grid would reduce the locational price separation which can currently exist in the nodal electricity market design. Also, as with the branch buffer idea, the scope of the contract grid when applied to resolving high prices due to net pivotal generation, would be something less than the entire grid. The HVDC link would be excluded and, quite possibly, key links into major load centres would be excluded as well.

6.45 With the contract grid, the pricing signal would more correctly reflect long-term risk/shortage, as transmission line capacities and losses would still be accurately modelled and priced. The short-term risk/shortage due to transmission outage would be dealt with using constrained-on payment. If the constrained-on cost was allocated to load customers, the short-term risk would be spread out to all load customers. This would reduce the risk exposure by local load customers in the region of locally net pivotal generation.

### Contract grid with limited side payments

6.46 A variant to the above approach would be to calculate final pricing based on the contract grid and not attempt to make up for the discrepancy between the dispatch and final pricing schedules. Under this approach generators would be paid for their dispatched generation but at final prices determined by the contract grid pricing solution.

6.47 This approach would mimic the competitive pricing outcomes prevailing in the isolated areas when transmission outages didn't occur, avoiding the need for costly resources to be used to increase competitive pressure on net pivotal generators. The obvious drawback is that a net pivotal generator wouldn't be compensated for any cost increases it incurs as a result of the transmission outage, and there would be no signal to other market participants to alter their behaviour.

## Discussion of illustrative remedies

6.48 The illustrative remedies sketched out above have various costs, benefits, and other consequences. Generally, remedies that impose a risk on Transpower as grid owner attempt to mitigate the price risk imposed by the net pivotal generator by pitting them against a well-resourced party with a rich suite of counter-measures. Some options available to the grid owner are simply unknown to the wider industry, the regulator, or the net pivotal generator. However, the

[12] This concept is based on TrustPower's discussion paper for the Scarcity Pricing Technical Group – 2 November 2010.

imposition of new incentive-based regulation on the grid owner would require coordination with the Commerce Commission and great care to avoid other costly side effects such as a reduction in maintenance or an increase of Transpower’s weighted average cost of capital.

6.49 The net pivotal declaration tackles the issue in the time dimension, enabling greater time for a local consumer or retailer exposed to the risk of high prices caused by the net pivotal generator to arrange credible alternatives that mitigate the level to which wholesale prices can be pushed up by the generator. A problem with this approach is that the provision of more time may not improve the credibility of alternative arrangements. Such would appear to be the case in respect of the Cobb situation, where the quantity of alternative supply required at what remains very short notice would simply not be feasible.

6.50 An approach that intervenes on price, by capping nodal prices during a declared net pivotal situation may simply socialise the price risk over many parties unless offers are capped as well. If offers are capped, they may be capped too low. This is a particular problem in hydro-dominated systems, where the valuation of water is a complex, multi-stage stochastic optimisation problem. Capping offers too low might lead to physical withholding or contracting outside the wholesale market not to withhold. However, offer and/or price caps do have the advantage of simplicity.

6.51 The last option discussed above, in which a contract grid solution is adopted without any constrained-on payments, is also simple but would under-reward net pivotal generators facing higher costs as a result of transmission outages.

## Glossary of abbreviations and terms

| | |
|---|---|
| **Act** | Electricity Industry Act 2010 |
| **Authority** | Electricity Authority |
| **Code** | Electricity Industry Participation Code 2010 |
| **Genesis** | Genesis Power Limited (trading as Genesis Energy) |
| **LDC** | Load duration curve |
| **LRMC** | Long-run marginal cost |
| **Meridian** | Meridian Energy Limited |
| **MRP** | Mighty River Power Limited |
| **MW** | Megawatt |
| **MWh** | Megawatt hour |
| **PDS** | Pre-dispatch schedule |
| **POCP** | Planned Outage Coordination Process |
| **SDPQ** | Schedule of dispatch prices and quantities |
| **SRMC** | Short-run marginal cost |
| **SWS** | Special winter schedule |
| **TP** | Trading period |
| **TrustPower** | TrustPower Limited |
| **WDS** | Weekly dispatch schedule |
| **WITS** | Wholesale Information and Trading System |