Market impact assessment of Arapuni split

Market Performance review

10 January 2012

702917-7

Investigation stages

Typically an in-depth investigation will 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. Typically there is no pre-announcement the Authority is doing 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. Typically there is a period of iterative information gathering and analysis. The Authority would typically publish the results of these reviews but wouldn’t pre-announce it is doing this work unless a high level of stakeholder or media interest was evident.

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

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

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

Contents

Executive summary 1

1 Introduction 3

2 Background to relevant transmission issues 3

3 Impact of Arapuni split on spot prices 5

4 Impact of Arapuni split on UNI locational advantage 11

5 Impact of Arapuni split on pivotal status of Arapuni generation 13

6 Conclusion 16

Appendix A Transpower's initial net benefit test 19

Appendix B Letter from Genesis 24

Appendix C Transpower's revised net benefit assessment 26

Appendix D Customer advice notice about Arapuni split 32

Appendix E Impact of Kinleith split 33

Appendix F Additional letter from Genesis 34

Appendix G Letter from Vector 42

Glossary of abbreviations and terms 45

Figures

Figure 1 Simplified network diagram indicating affected 110kV network 4

Figure 2 North Island price distribution on 16 August 2011, trading period 38 6

Figure 3 North Island price distribution on 16 August 2011, trading period 38 with Arapuni split 7

Figure 4 Comparison of 16 August 2011, trading period 38 final prices 8

Figure 5 Comparison of locational price differences on 16 August 2011, TP 38 9

Figure 6 Comparison of final prices at Otahuhu and Kinleith 10

Figure 7 Comparison of nodal price differences between UNI and other locations 11

Figure 8 Comparison of Otahuhu to Whakamaru price differences 12

Figure 9 Comparison of Otahuhu to Haywards price differences 13

Figure 10 Market network diagram indicating affected region 14

Figure 11 Chronological plot of demand, generation and transfer limits at Kinleith 15

Figure 12 Potential net pivotal ability of Arapuni at Kinleith GXPs with the Arapuni split 16

Figure 13 Indication of system splits implemented at Kinleith (Sep 09 – Aug 11) 33

Executive summary

Transpower has implemented a permanent bus split at Arapuni to relieve transmission constraints in the upper North Island (UNI) region and reduce the need to constrain back generation from Arapuni. Under the Electricity Industry Participation Code (Code), Transpower is required to demonstrate a net benefit from permanent grid reconfigurations, which it has done[1].

Genesis Energy (Genesis) raised concerns around the regular opportunities this reconfiguration affords Mighty River Power (MRP) to exercise market power, primarily at the Kinleith grid exit points (GXPs), and that these market impacts should be included within the net benefit assessment[2]. Genesis subsequently provided a follow up letter to Transpower with a brief assessment of these potential market impacts[3].

The Electricity Authority (Authority) has conducted this review to consider the potential impacts of the Arapuni bus split on the wholesale electricity market. The analysis concludes that the permanent Arapuni bus split:

- reduces the potential for price separation between the UNI region and the rest of the system, as well as reducing the local pivotal[4] ability of generators in the UNI by increasing the transmission capability into the region. This would reduce locational price risk in the UNI region that would have a flow on effect on local hedge and retail markets; and
- increases the local pivotal ability of Arapuni generation connected to the Kinleith GXP, particularly when the Kinleith co-generation plant is operating at reduced output, or is out of service. This could increase locational price risk into the Kinleith area and consequently have a flow on effect on hedge and retail markets at the Kinleith GXPs.

Therefore, the Arapuni bus split introduces the market trade-offs of the potential for greater competition benefits in the large retail markets of the UNI region versus a potential reduction in competition benefits at the smaller retail markets at the Kinleith GXPs (Kinleith area). The competition benefits of the Arapuni bus split to the UNI region should be reviewed following the introduction of the 400kV capable line into Auckland, which is expected to be commissioned in October 2012.

This report details the review conducted by the Authority and considers the potential impacts of the Arapuni bus split on the wholesale electricity market. Potential amendments to the Code, which are now in the Authority's work programme, are also considered.

1 See Appendix A and Appendix C.

2 See Appendix B.

3 See Appendix F.

4 This is the ability of generation to set prices in a region by increasing offer prices.

1 Introduction

1.1 On 29 September 2011, Transpower implemented a permanent bus split at Arapuni. This was done to reduce the constraints on Arapuni generation and increase the transmission capability through the 220kV transmission system into the UNI region. Without this split, the constraints on the 110kV transmission system restricted the transfer capability on the parallel 220kV system into the UNI region, and also constrained back the Arapuni generation.

1.2 Transpower undertook a net benefit test, as required under the Code. In this assessment Transpower demonstrated the Arapuni split delivers a benefit of $2.34M per year. This was primarily due to a reduction in fuel costs with the increased usage of local generation at Arapuni, that would otherwise have been provided by generation elsewhere with higher fuel costs, and also due to a reduction in transmission losses.

1.3 The cost of implementing the Arapuni split was $0.131M. The split also reduces the need to declare Grid Emergencies and split the grid at Kinleith[5], in turn reducing the security of supply to loads at the Kinleith GXPs. The Arapuni split is expected to be an interim measure until the new 220kV line into Auckland is commissioned. At that time the need for the bus split at Arapuni will be reviewed.

1.4 Genesis raised concerns around the potential for MRP to exercise market power, at the Kinleith GXPs, due to the locational advantage it is afforded by the bus split at Arapuni. Furthermore, Genesis indicated the net benefit test carried out by Transpower did not consider these implications, which it considers ought to have been included.

1.5 The original proposal and net benefit assessment, from Transpower, was to implement the Arapuni bus split during daytime hours (6am to 9pm) on week days, as shown in Appendix A. Following revisions in assumptions and feedback from the system operator[6], Transpower revised the proposed implementation of the Arapuni bus split to a permanent one. This was communicated at a meeting of industry participants on 09 September 2011. Transpower updated the net benefit assessment to reflect these changes[7]. The revised assessment indicates a positive benefit of $3M and cost of $0.156M (with a permanent implementation of the Arapuni split).

1.6 A customer advice notice (CAN) was issued on 23 September 2011 informing the industry of the implementation of the Arapuni bus split. This is shown in Appendix D.

2 Background to relevant transmission issues

2.1 During periods of low UNI generation, there is greater transfer across the 220kV transmission system into the UNI. Under these conditions, there is a risk that a trip of the 220kV line between Whakamaru and Hamilton can overload the parallel 110kV transmission lines between Kinleith and Tarukenga, as this line tries to carry the increased load to supply the UNI. Increased generation at Arapuni reduces the post contingency loading on the Kinleith-Tarukenga circuits.

2.2 The transmission capacity from Arapuni was reduced following the decommissioning of the Arapuni-Pakuranga line in 2010. As a result the Arapuni-Hamilton circuits have become more

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5 This is to manage post contingency loadings on the 110kV Kinleith-Tarukenga circuits.

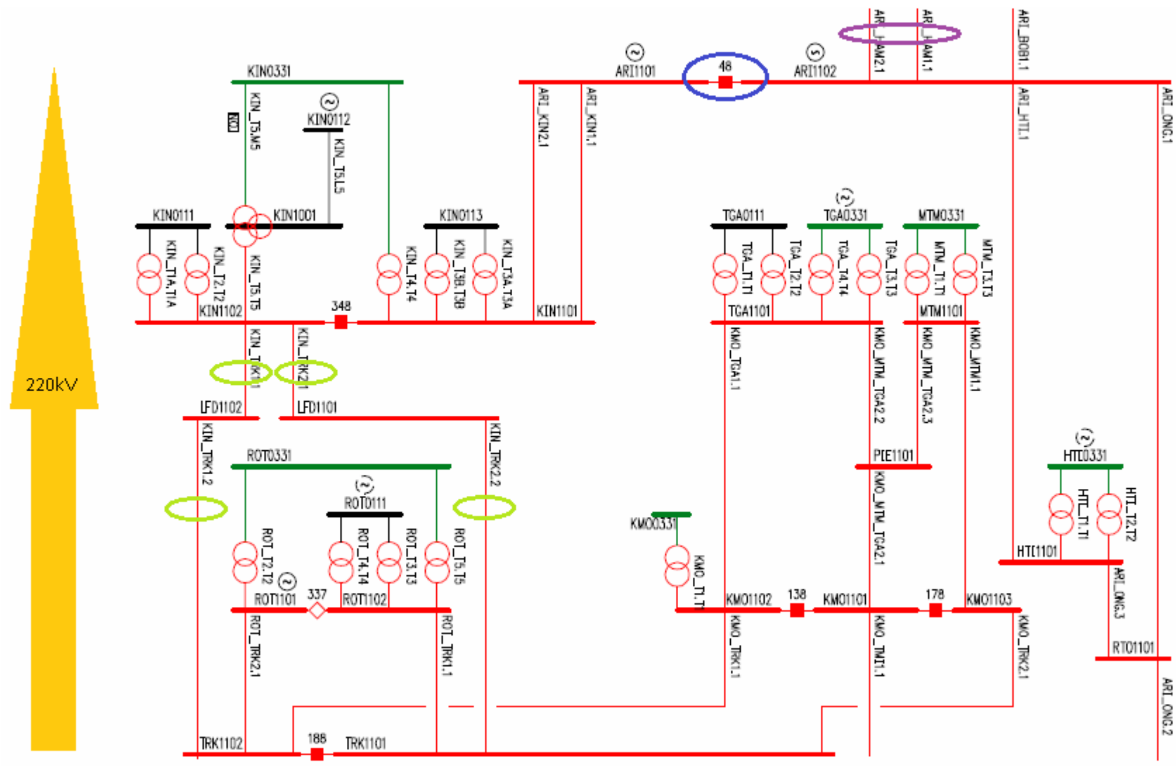
6 The original net benefit assessment by Transpower assumed that MRP would have difficulty in managing water flows with the split in place overnight. These assumptions were incorrect and revised. Furthermore, the system operator indicated there was an increased risk of implementing incorrect constraints into the market scheduling and dispatch process if the Arapuni split had to be managed on a daily basis. This is because the constraints in this part of the network are also dependent on the status of five special protection schemes in the area.

7 See Appendix C.

prone to constrain. This restricts the output of generation from Arapuni, thus reducing the ability to manage the constraint on the Kinleith-Tarukenga circuits, through increasing Arapuni output. This has resulted in the system operator increasingly declaring Grid Emergency Notices and using the split at Kinleith[8] to manage the transmission security constraints on the Kinleith-Tarukenga circuits instead.

2.3 A simplified schematic of the market network configuration illustrating the binding 110kV transmission lines are illustrated in Figure 1. The constraining lines between Arapuni and Hamilton are highlighted in purple and those between Kinleith and Tarukenga are highlighted in green. The Arapuni bus split is highlighted in blue[9]. The parallel 220kV transmission system is illustrated by the orange arrow.

Figure 1 Simplified network diagram indicating affected 110kV network



Source: Electricity Authority

2.4 T

The above conditions arose from 23 to 27 January 2011. During this time, the binding 110kV transmission constraint between Kinleith and Tarukenga resulted in the system operator implementing the split at Kinleith. However, this transferred the transmission constraint onto the 220kV transmission system.[10] The system operator did not have a constraint within the market clearing engine (SPD) to manage this constraint. As a result the system operator constrained on generation in the UNI, outside the market scheduling process, at a cost of $6.5M to spot market

8 The Authority understands from Transpower that the preferred alternative would have been to split the network at Arapuni since the Kinleith split has security implications for the loads supplied from the Kinleith GXP. The split at Arapuni required some additional work, which has since been completed and implemented.

9 The Arapuni split places generators from Arapuni station on either side of the split.

10 This binding 220kV transmission limit has since been upgraded in April 2011.

purchasers. This event was the subject of a review by the Authority[11] of which one of the findings was a lack of information provided to participants during constrained on situations. The system operator[12] now publishes customer advice notices (CANs) in near real time, informing participants about the application of discretionary action to constrained-on generators.

3 Impact of Arapuni split on spot prices

3.1 To understand the potential impact of this grid reconfiguration on market prices, the Authority analysed instances from May[13] to August 2011 when the 110kV Arapuni-Hamilton or Kinleith-Tarukenga transmission lines constrained the flow of electricity. Our analysis identified 34 trading periods for the period of analysis when binding constraints occurred. A "what if" market price was then calculated assuming the Arapuni bus split was implemented for these trading periods.

3.2 One such instance was on 16 August 2011 during trading period 38. During this trading period, a binding constraint occurred on the Kinleith-Tarukenga 110kV transmission lines, due to overloading caused by a possible outage of the Hamilton-Whakamaru 220kV line. The binding constraint resulted in some price separation within the UNI region. This was due to high northward power flows to supply high North Island load[14] as well some UNI generation being on outage[15]. To manage the high North Island load some out of merit generation was dispatched, thus resulting in the observed price separation. An illustration of the price variation across the North Island is illustrated in Figure 2.

[11] See analysis of Dispatch of unscheduled generation: 23-27 January 2011 available from http://www.ea.govt.nz/industry/monitoring/reports-publications/investigations-by-year/investigations-2011/

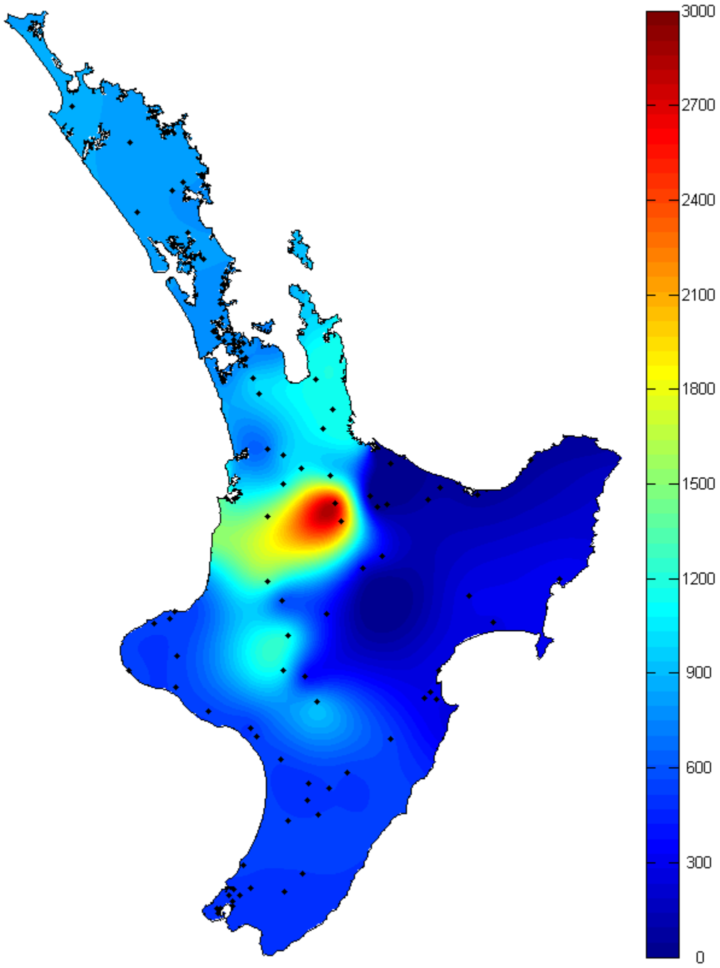
[12] The system operator has also implemented its automatic constraint builder application (SFT), which would reduce the time needed to generate transmission constraints and therefore the need to constrain on generation.

[13] The 220kV network between Hamilton and Whakamaru has been reconfigured to its current state from May 2011. This time period was used to understand the potential impacts of the reconfiguration against the alternative (which is the current network configuration).

[14] North island load was 209MW greater when compared to the same period from the previous week.

[15] Two Huntly units were out of service and there was no generation from Glenbrook.

Figure 2 North Island price distribution on 16 August 2011, trading period 38

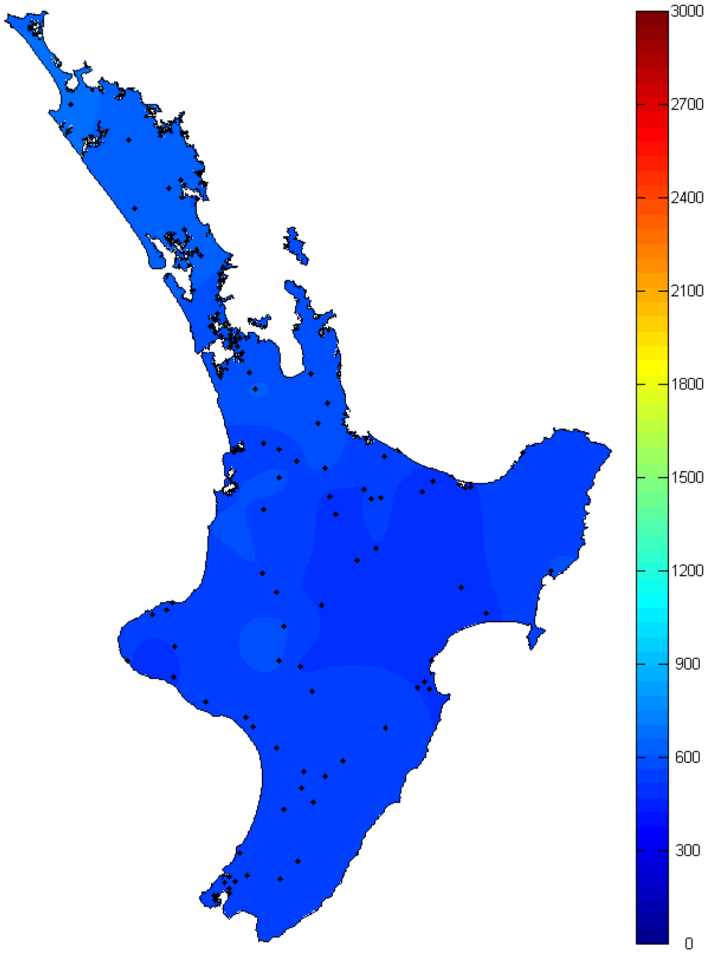


Source: Electricity Authority

Notes: 1. Prices in dollars per MWh

3.3 Implementing the split at Arapuni relieves the constraint on the Kinleith-Tarukenga 110kV transmission lines, and therefore the need for the out of merit generation in the region to manage the constraint. This reduces the prices in the constrained regions (both the Kinleith area and the wider UNI region) and removes the intra island price variation, as illustrated in Figure 3. The observed price separation within the North Island, with the Arapuni bus split in place, is much lower.

Figure 3 North Island price distribution on 16 August 2011, trading period 38 with Arapuni split

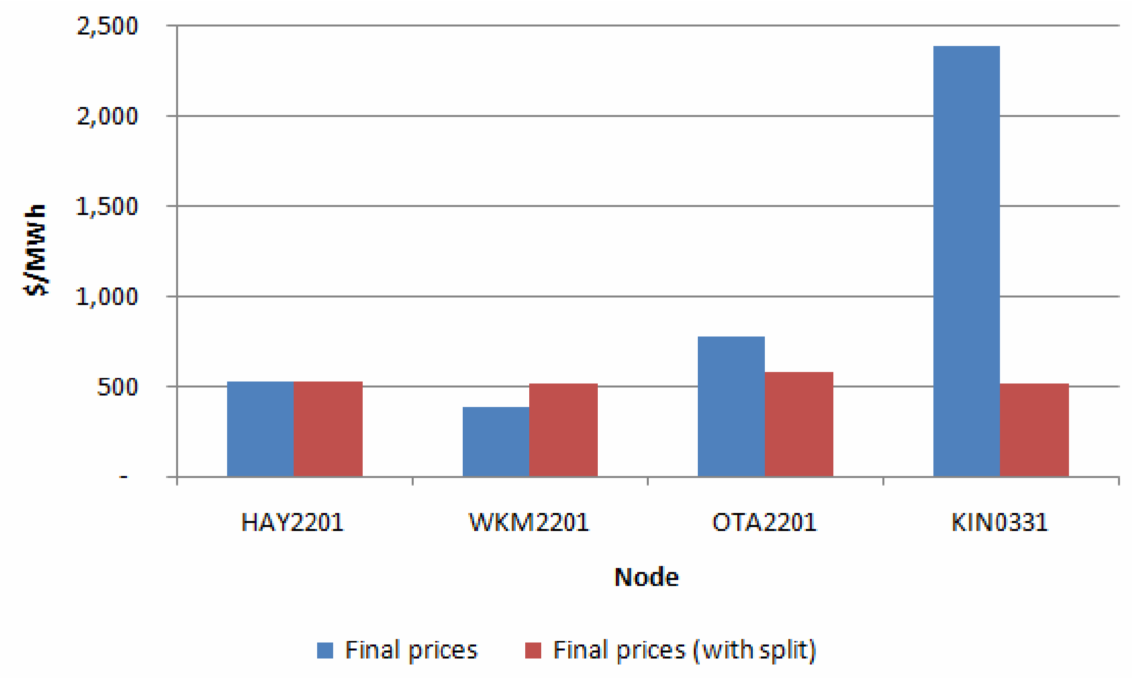


Source: Electricity Authority

Notes: 1. Prices in dollars per MWh

3.4 A comparison of nodal energy prices at several locations is shown in Figure 4, to better illustrate the impact of the split. The price at Kinleith is the most affected due to its relative electrical proximity to the constraint. In this instance the Kinleith GXP (KIN0331) price reduces by 79% and the Otahuhu 220kV (OTA2201) nodal price reduces by 25%. The price at the Whakamaru 220kV node (WKM2201) increases by 33% in this instance, with the introduction of the Arapuni bus split. This increase at Whakamaru is due to generation being constrained down in the UNI region, due to the transmission constraint, thus suppressing the price at the Whakamaru node in the base case scenario. The removal of this constraint increases generation in the region and removes the associated price suppression.

Figure 4 Comparison of 16 August 2011, trading period 38 final prices



Source: Electricity Authority

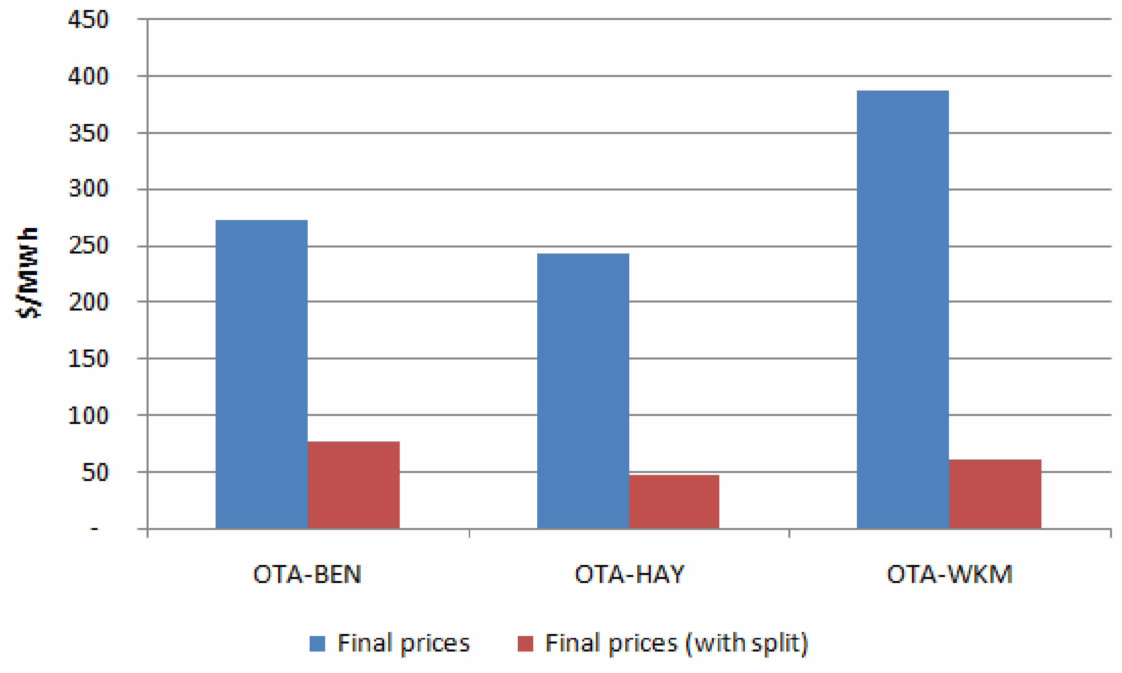
3.5 In addition to affecting absolute nodal prices, removing the potential for transmission constraints also impacts nodal price separation, which affects the locational price risk[16] faced by participants.

3.6 Figure 5 illustrates the price difference between certain nodes on the network during trading period 38 on 16 August 2011. As can be seen, the removal of the constraint with the introduction of the split at Arapuni has a potentially significant impact in reducing locational price risks faced by participants. The price difference between Otahuhu (OTA) and Whakamaru (WKM) in this instance reduces by 84% with the introduction of the Arapuni bus split, as compared to the actual locational price difference observed during this time.

3.7 On 16 August 2011, the system operator issued a grid emergency notice and subsequently implemented a split at the Kinleith bus to relieve these transmission constraints and removed the price separation. This split at Kinleith is discussed further in Appendix E.

[16] This is the price risk faced by participants which buy energy at one node and sell energy at another node. When these nodal prices differ significantly, as they could under transmission constrained scenarios, the buy price could significantly exceed the sell price thus exposing the participant to the price difference.

Figure 5 Comparison of locational price differences on 16 August 2011, TP 38

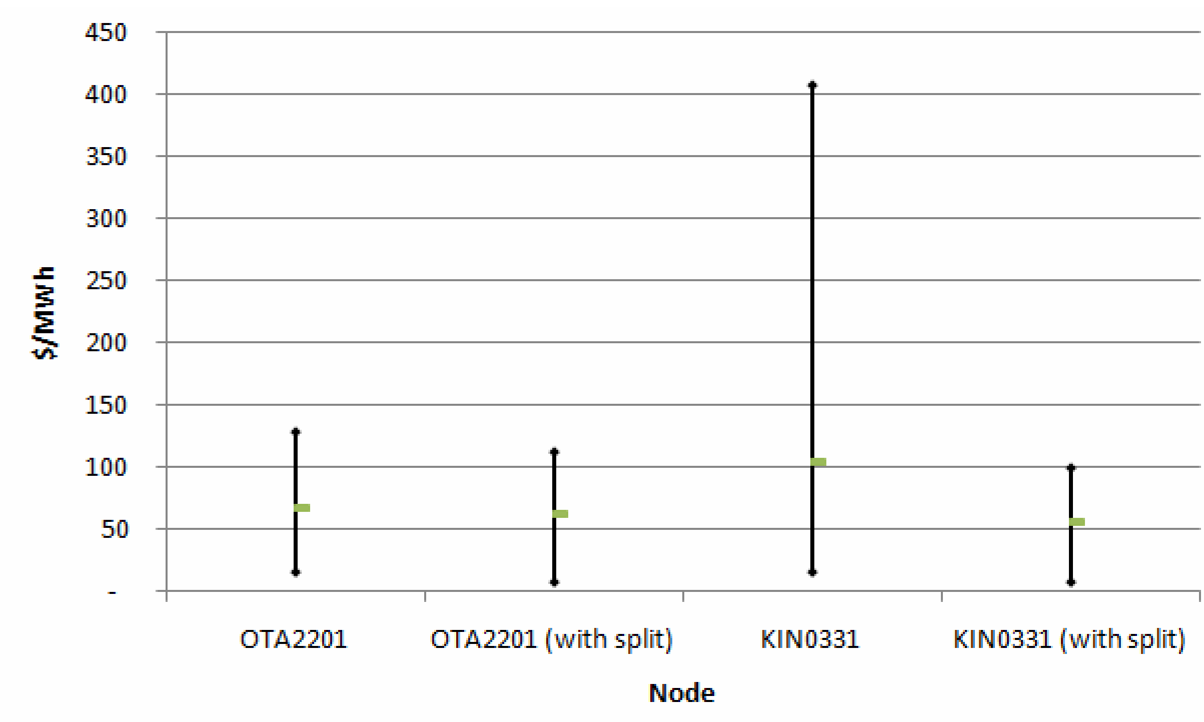


Source: Electricity Authority

3.8 The above analysis was conducted for the other 33 instances identified from May to September 2011 to observe the potential impact of the Arapuni bus split on the market prices and the locational price differences. The results of this are shown in Figure 6, which illustrates the comparative range in Otahuhu and Kinelith prices in these instances.

3.9 These indicate that the introduction of the Arapuni split has some effect on reducing average prices at Otahuhu and Kinleith, although the greater impact is the reduced volatility in prices due to the removal of the transmission constraints in the UNI region. Being closer to the constraint implies that the price at Kinleith is more sensitive to the removal of the transmission constraints in the area.

Figure 6 Comparison of final prices at Otahuhu and Kinleith



Source: Electricity Authority

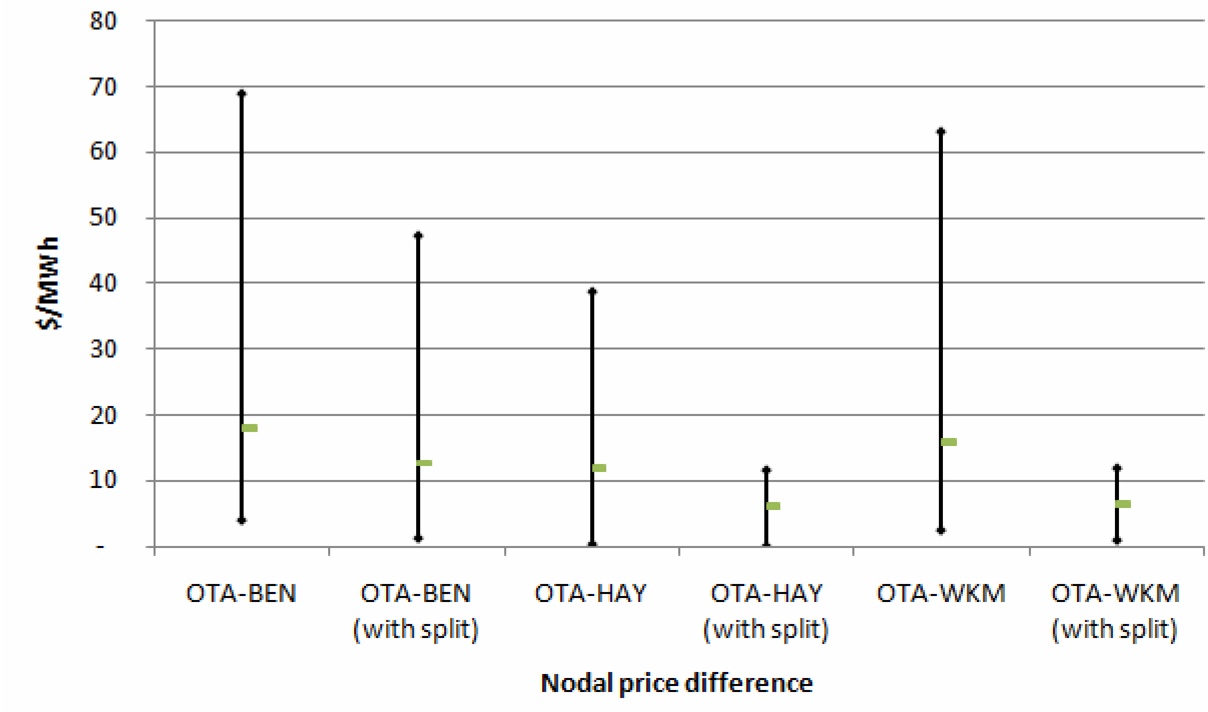
Notes:
1. The affected date range is May 2011 to August 2011.
2. Minimum, maximum and average prices (green bar) are illustrated.

3.10 The impact of the Arapuni bus split on the nodal price differences between the Otahuhu node (OTA) in the UNI and several other locations (Benmore (BEN), Haywards (HAY) and Whakamaru (WKM)) on the network is shown in Figure 7.

3.11 This illustrates that the removal of the constraint, due to the Arapuni bus split, reduces the likelihood of larger price separations between the UNI and nodes in different locations on the network. This can be observed, in Figure 7, by the reduced range of observed price separation between OTA and the other locations. This reduction in the locational price differences and its volatility would reduce the potential locational price risk faced by participants.

3.12 The impact on market prices in this section assumes no response from market participants with the introduction of the bus split at Arapuni. This assumption is relaxed in the next two sections where the impact of participant's ability to be pivotal in a region is explored.

Figure 7 Comparison of nodal price differences between UNI and other locations



Source: Electricity Authority

Notes:
1. The affected date range is May 2011 to August 2011.
2. Minimum, maximum and average price differences (green bar) are illustrated.

4 Impact of Arapuni split on UNI locational advantage

4.1 The increased transmission capability into the UNI reduces the generation requirements from this region. To understand the potential impact of this increased transfer capability on the locational advantage of generators in the UNI, the constrained instances from section 3 were analysed, but with increased offer prices from Genesis for its Huntly generation. The ability of these increased offer prices to set the marginal price in the UNI would provide an indication of the pivotal ability of Huntly generation in this region. This pivotal analysis was repeated with the Arapuni bus split in place.

4.2 The price difference between the Otahuhu and Whakamaru 220kV market nodes and the Otahuhu and Haywards 220kV market nodes with and without the split are illustrated in Figure 8 and Figure 9 and provide an indication of the locality of the price impacts.

4.3 A large price difference is an indication of localised high prices which in turn provides an indication of the ability to increase local prices (i.e. pivotal in the region).

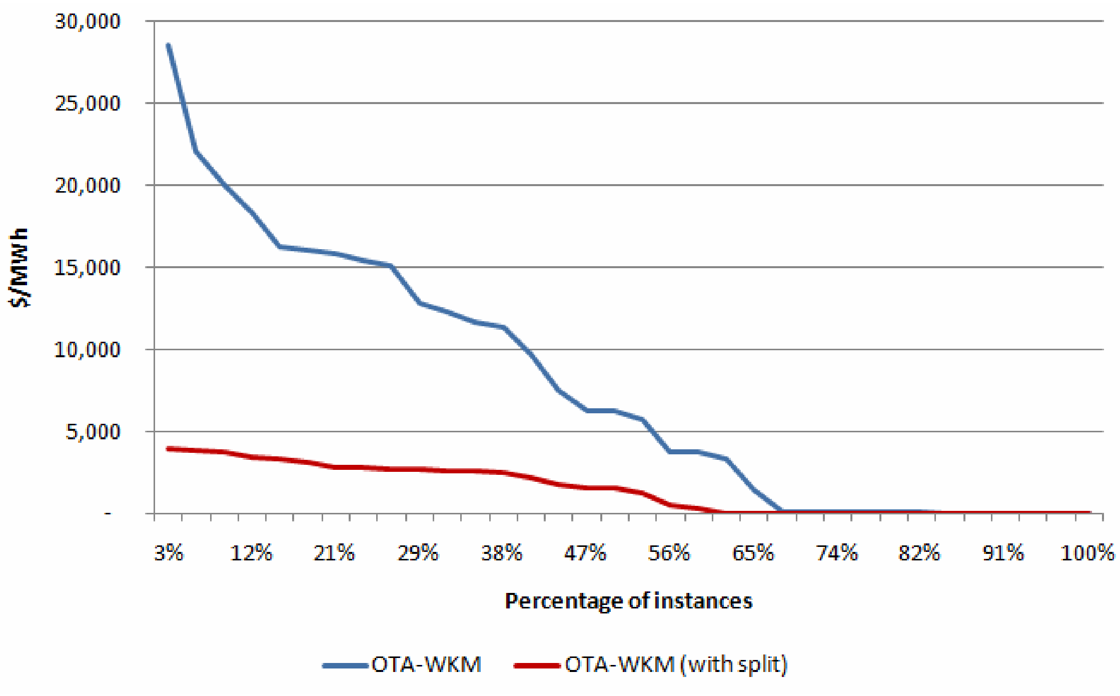
4.4 Figure 8 and Figure 9 illustrates a reduction in the ability of Huntly to significantly increase UNI prices with the Arapuni bus split in place. As an example, the introduction of the split reduced the number of instances where the price difference between Otahuhu and Whakamaru was greater than $1,000/MWh by 12% and provided a 53% reduction in the number of instances with a Otahuhu-Whakamaru price difference greater than $5,000/MWh. Reductions of 12% and 9% are observable for the same price difference thresholds of $1,000/MWh and $5,000/MWh respectively between Otahuhu and Haywards with the split.

4.5 The reduction in price differences between the UNI and the central and lower North Island, due to the introduction of the Arapuni split, illustrates the reduced ability of generators in the UNI to significantly increase the prices in the region, under this reconfiguration.

4.6 This reduction in local pivotal ability of UNI generators reduces the potential locational price risk into the region, increasing the potential for competition[17]. Participants without sufficient generation in the UNI would have to manage their locational price risk. A reduction in their locational price risk would also reduce their transaction costs.

4.7 The reduced locational advantage, reduced transaction costs and increased competition could filter into the UNI hedge and retail markets.

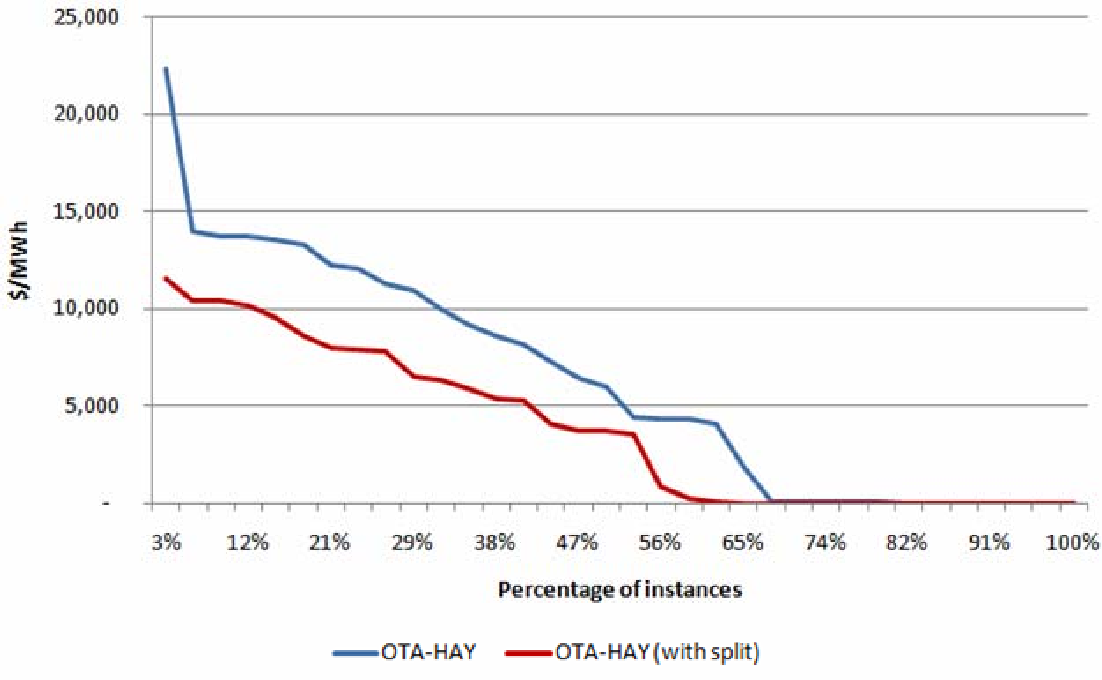
Figure 8 Comparison of Otahuhu to Whakamaru price differences



Source: Electricity Authority

[17] The Authority's analysis indicates that the next potential issue with low UNI generation and the constraint north of Whakamaru relieved is to get power through the Wairakei ring. The Wairakei ring upgrade has been approved, with an expected commissioning date of April 2013. Further details are contained on the Transpower website: http://www.gridnewzealand.co.nz/n1652.html

Figure 9 Comparison of Otahuhu to Haywards price differences



Source: Electricity Authority

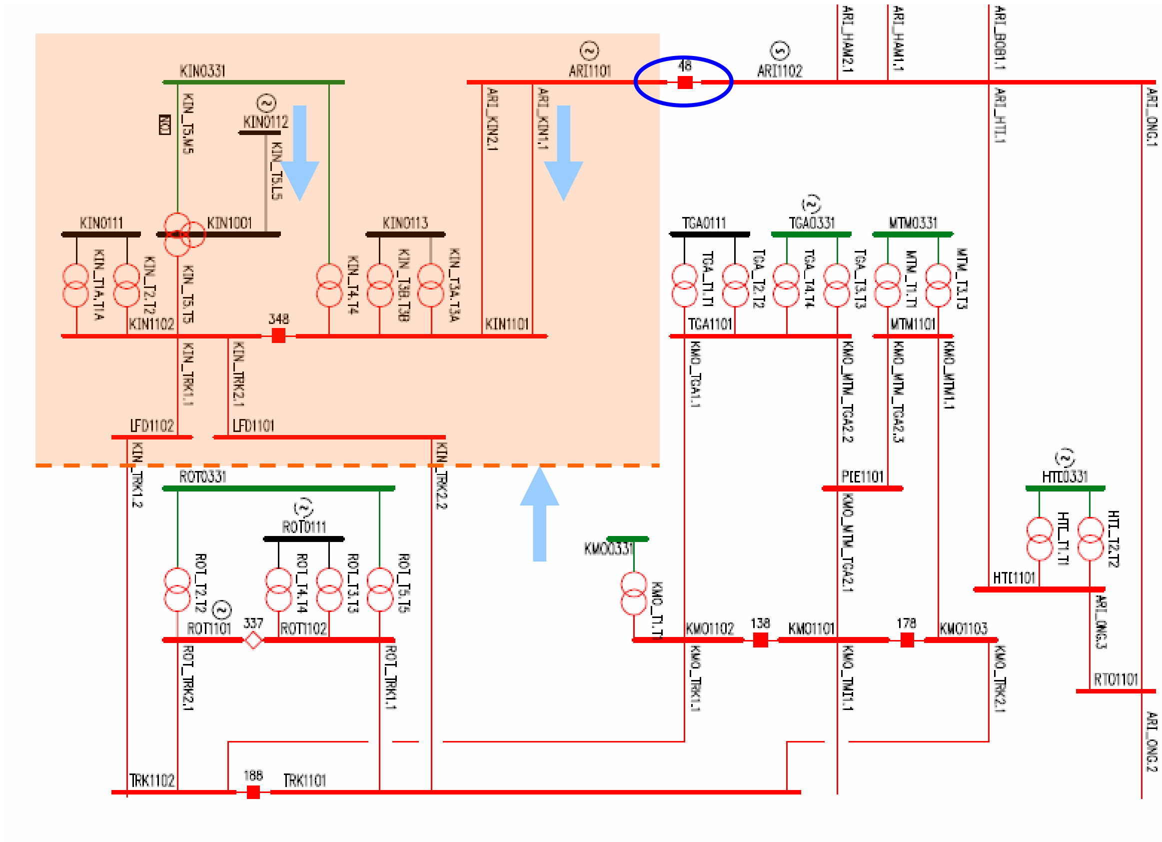
5 Impact of Arapuni split on pivotal status of Arapuni generation

5.1 Genesis raised concerns regarding the implications of the grid change at Arapuni and the potential opportunities it affords MRP to set prices at the Kinleith GXPs.

5.2 This concern stems from the minimum generation required from Arapuni to support the Kinleith load with the Arapuni split in place. This minimum generation is needed to manage the flows on the Kinleith-Tarukenga circuits below their security limit. Transpower also requires three units at one of the Arapuni market nodes (ARI1101) (see Figure 10) for voltage support.

5.3 Figure 10 illustrates the affected network with the Arapuni split highlighted (blue circle). Also indicated are the potential binding security constraints on the Kinleith-Tarukenga circuits with the Arapuni split in place (orange dashed line), the main sources of electricity supply for loads in the region are illustrated with the blue arrows and the affected constrained region is highlighted in orange.

Figure 10 Market network diagram indicating affected region



Source: Electricity Authority

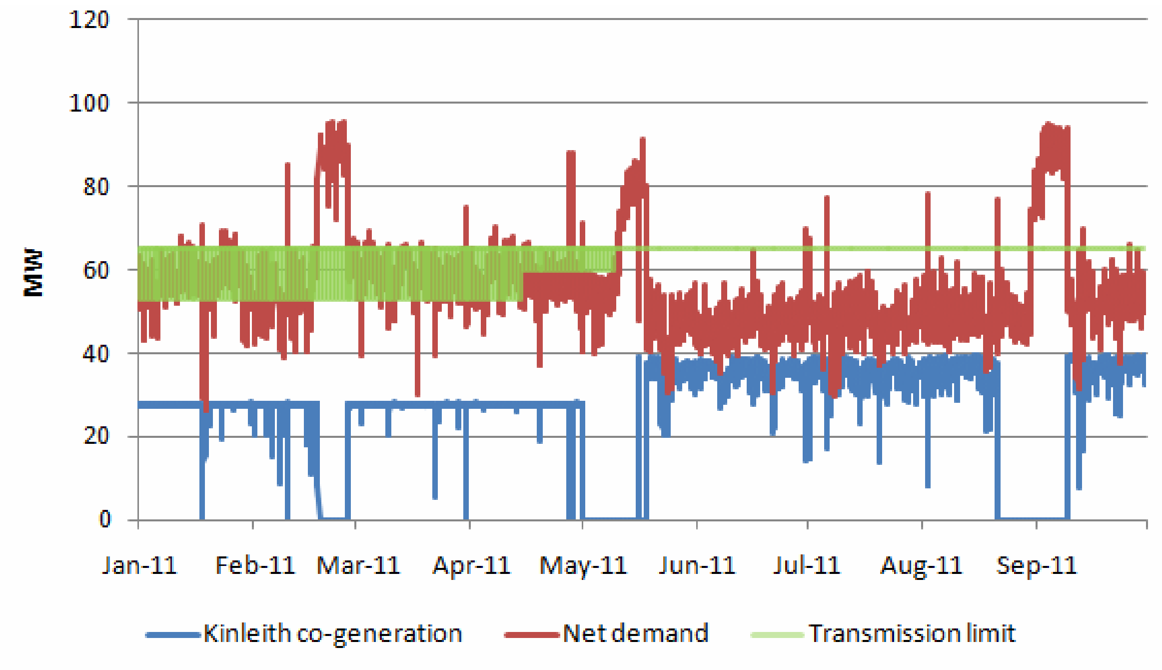
5.4 To initially understand the potential minimum generation requirements from Arapuni with the split in place, the net load in the Kinleith area was compared to the available transmission capacity into the region.

5.5 Figure 11 illustrates the net demand (red line) in the affected region and the transmission security limit into the region (green line) from January 2011 to September 2011. The net demand is calculated by netting off the local generation from Kinleith from the consumption (gross demand) at the Kinleith GXPs. The portion of the net demand above the transmission security limit[18] provides an indication of the minimum generation required from Arapuni to supply the load in the affected region whilst satisfying the transmission security limits into the region. The Kinleith co-generation is also shown (blue line) to illustrate its impact on the minimum generation requirements from Arapuni.

5.6 This historical comparison illustrates the must run requirements from Arapuni generation are primarily during those periods when the Kinleith co-generation is operating at reduced output or on outage. This requirement is increased further during summer with the reduced transmission limits.

[18] The oscillation of the transmission security limits during the summer and shoulder periods is due to them reverting to the higher winter limits over the evening and earlier morning periods (21:00 to 06:30).

Figure 11 Chronological plot of demand, generation and transfer limits at Kinleith



Source: Electricity Authority

Notes:
1. SCADA data was obtained from EM6
2. Net demand is defined as the gross demand less the Kinleith co-generation

5.7 Since April 2011, separate Arapuni offers were being made at the two Arapuni market nodes (ARI1101 and ARI1102). The maximum ability of Arapuni to be pivotal at the Kinleith GXPs during this time was explored by implementing the Arapuni split and increasing the offer price of Arapuni generation at the ARI1101 market node[19]. This assumes that all of the generation offered by MRP at the ARI1101 market node (greater than $0 per MWh) is used to leverage any locational advantage when the Arapuni split is in place.

5.8 The results of this pivotal experiment are shown in Figure 12. The Kinleith nodal price, Kinleith co-generation output and scheduled must-run generation (pivotal quantity) from Arapuni at the ARI1101 market node are illustrated.

5.9 The results of this analysis indicates that for 22% of the time, from April 2011 to September 2011, the high priced offers from Arapuni generation would be needed to supply the Kinleith load. The pivotal ability of Arapuni at the ARI1101 market node is most acute when the Kinleith co-generation is on outage or operating at reduced output[20] (as indicated by the red line). The reduced Kinleith co-generation output (red line) increases the must-run requirements (pivotal quantity) from Arapuni (blue line). This is due to the limited transmission capacity into the region.

5.10 For MRP to exploit this locational advantage, low Arapuni generation at the ARI1101 market node is required during some periods, as indicated by the blue line in Figure 12. With three generating units required by Transpower for voltage support, this implies that MRP would need to manage its hydrology requirements using primarily the remaining five units on the ARI1102 market node. This could restrict this pivotal ability. As an example, if MRP required at least one unit to generate

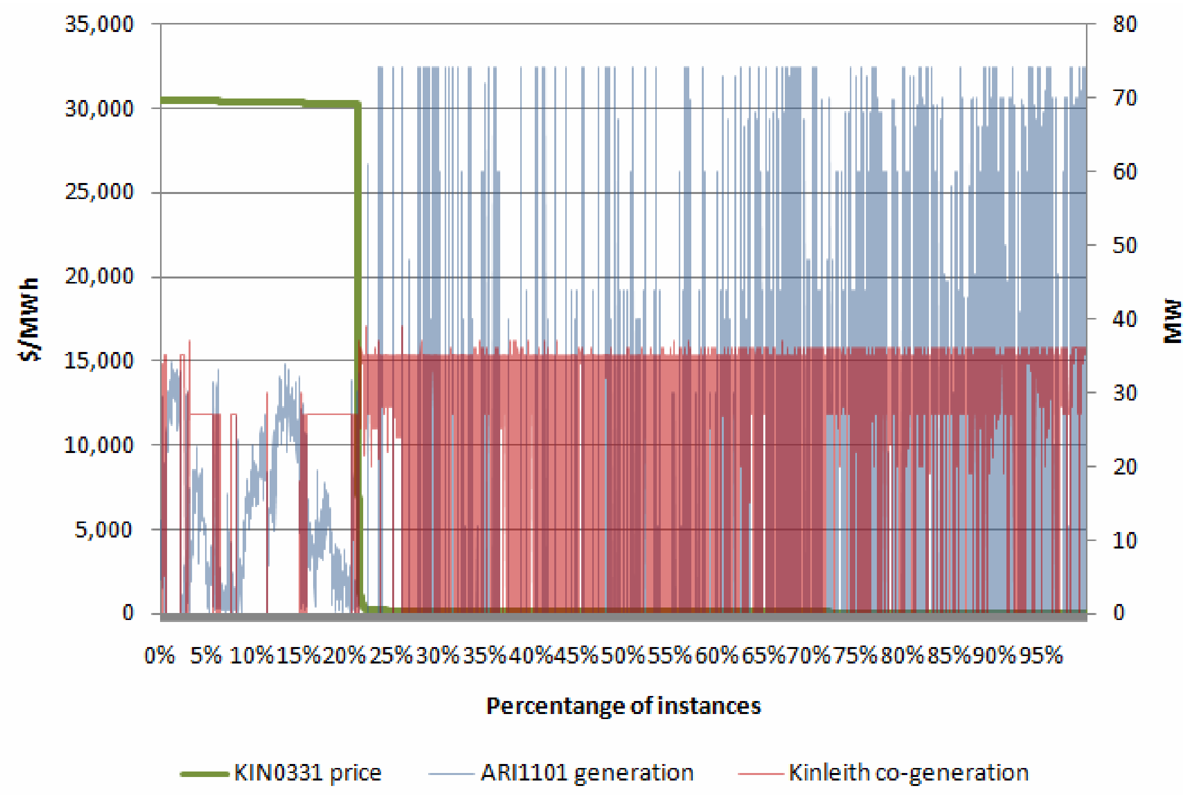
[19] This is similar to the pivotal analysis carried out for Huntly generation in section 4.

[20] This is consistent with the initial analysis shown in Figure 11.

on the ARI1101 market node, the proportion of instances that MRP would have been pivotal in the region would have reduced by 75%, and requiring two units would remove this ability.

5.11 This pivotal ability of Arapuni at the Kinleith GXPs could impact local hedge and retail markets at the Kinleith GXPs.

Figure 12 Potential net pivotal ability of Arapuni at Kinleith GXPs with the Arapuni split



Source: Electricity Authority

6 Conclusion

6.1 The Authority has met with Transpower to discuss the technical requirements for the Arapuni split and the additional minimum requirements from Arapuni to support the load at Kinleith.

6.2 The current Arapuni split reduces the potential for transmission constraints into the UNI, which in turn reduces the locational advantage of generators in this region, relative to the configuration prior to the split[21]. The Authority considers this reduced locational advantage and increased transmission capability into the region would reduce locational price risk and increase competition in this large retail market.

21 This is the configuration referred to in paragraph 2.1 and 2.2.

6.3 The analysis also indicates an increased locational advantage of Arapuni generation in supplying the load at the Kinleith GXPs. This advantage could reduce the potential for competition in the region if locational market power was exercised in this region. The ability of Arapuni to extract this advantage is dependent on whether the Kinleith co-generation is on an outage and whether MRP can manage its generation requirements in the region on the remaining units whilst still satisfying the system operator's voltage support requirements.

6.4 Generators from time to time find themselves in net pivotal positions at various locations in the network under certain circumstances (e.g. Cobb and Tuai). Indeed the existence of this intermittent ability to be pivotal may be a necessary feature of an efficiently sized transmission grid. The Authority is also conscious of the fact that the existence and exercising of market power could also be indicative of other potential market failures, which could adversely affect the efficient operation of wholesale and associated retail and hedge markets. The Authority will continue to monitor the conduct of generators in pivotal situations.

6.5 While the current provisions in clause 12.117 of the Code does provide for a net benefit assessment of permanent grid reconfigurations, the Authority believes that this assessment could be more sensitive to the potential market effects. As an example, potential competition benefits, reduction of barriers to new entrants and reduction in market transaction costs could be some of the issues considered within these wider market effects. The application of the assessed market impacts could operate in a similar manner to the Code amendment principles, and be used as a tie breaking mechanism amongst different alternatives where the net-benefit assessment is inconclusive in revealing the best option. Furthermore, the Authority believes that a process sensitive to the potential market effects would be better placed to deliver solutions that improve the net benefit of all affected participants relative to an alternative, which is indifferent to these effects.

6.6 Transpower has raised an issue with the Authority about the time lag with the current process for approving grid reconfigurations within the Code, particularly when adverse conditions arise and are likely to persist for some time (e.g. reduced South Island hydro storage levels[22]). Transpower indicated a need for an intermediate process with reduced time horizons to facilitate medium term network reconfigurations, which have clear net benefits to the system, under adverse system conditions. An approach to this could be to introduce a pre-approval process within the Code for specified network reconfigurations under defined pre-conditions. Transpower would then be required to identify the existence of these pre-conditions before proceeding with the pre-approved reconfiguration. This could assist in reducing potential time lags in the approval process.

6.7 These potential developments will feed into the Authority's Code amendment process with input from the wider industry.

[22] The following example was provided by Transpower. In 2008, during the dry year, Transpower were seeking to get power to the South Island, and in particular, the lower South Island (given there were constraints from Benmore to the south of the South Island). Transpower were wanting to reconfigure the grid to achieve higher power transfer on the Clyde-Twizel circuits. Network Waitaki understood the issue and were wanting to assist, however they did not feel able to give permission for the split as this would result in some of their customers being placed on n-security. In the event of a loss of supply, Network Waitaki was concerned about potential liability.

Appendix A Transpower's initial net benefit test

TRANSPOWER

Arapuni Grid Reconfiguration

Net Benefit Test

August 2011

1 Introduction

In 2010 Transpower decommissioned the Arapuni–Pakuranga 110 kV circuit to allow construction of the new 400 kV-capable transmission line to Auckland. This decommissioning increased generation constraints at Arapuni required to manage post-contingency loadings on the Arapuni–Hamilton circuits. A generation runback scheme at Arapuni was installed to allow greater pre-contingency generation at Arapuni.

We have identified that implementing a bus split at Arapuni will further relieve Arapuni generation constraints and also reduce system losses. This is an interim measure until our new 400 kV-capable line to Auckland is commissioned. At this time the need for the split will be reviewed.

We consider the use of a bus split at Arapuni to be an acceptable interim measure similar to the use of special protection schemes for the same purpose. This is discussed in greater detail in our Transmission Code of Practice (http://www.gridnewzealand.co.nz/n4763,375.html).

We propose to implement a system split at Arapuni between 6am and 9pm on weekdays. The system split would be a permanent change in the way the grid is configured so we have applied the net benefit test which Transpower is required to carry out when permanently reconfiguring the grid.

2 Background

We recently reconfigured the 110 kV bus at Arapuni. This enables us to easily implement a system split at Arapuni and close that split when required. The split has three Arapuni generating units connected to the circuits to Kinleith and five generating units connected to the circuits going to Ongarue, Hangatiki, Hamilton and Bombay.

The bus split relieves constraints on generation at Arapuni power station. The installed capacity at Arapuni is 180 MW. The power station can be constrained back to 100 MW at times of very low generation in the Upper North Island. It should be noted that the bus split will not completely relieve constraints at Arapuni.

The split will also relieve the need for the System Operator to declare grid emergencies to split the system at Kinleith to manage loading on the 110 kV circuits between Tarukenga, Kinleith, Arapuni and Hamilton.

The split does require a minimum amount of generation at Arapuni from the generating units connected to Kinleith. This is to maintain security of supply to Kinleith and Lichfield and to manage voltages.

3 Net Benefit Test

Section 12.117 of the Electricity Industry Participation Code requires Transpower to demonstrate a net benefit for any permanent reconfiguration of the grid. The following benefits and costs should be estimated where applicable:

- Changes in fuel costs incurred by a generator
- Direct labour and material costs incurred by Transpower and the designated transmission customers
- Changes in estimated maintenance costs including Transpower's and any designated transmission customer's costs
- Any change in the estimation of expected unserved energy
- Changes in fuel costs of existing assets, committed projects and modelled projects

- Changes in the value of involuntary demand curtailment
- Changes in the costs of demand-side management changes in costs resulting from deferral of capital expenditure on modelled projects
- Changes in costs resulting from differences in the amount of capital expenditure on modelled projects
- Changes in costs resulting from differences in operations and maintenance expenditure on existing assets, committed projects, and modelled projects
- Changes in costs for ancillary services
- Changes in losses, including local losses
- Changes in subsidies or other benefits provided under or arising pursuant to all applicable laws, regulations and administrative determinations.

4 Methodology for analysis

4.1 Losses and generation fuel costs

We used historic load, generation, capacitor switching and voltage setpoint information for 2010 to estimate reduction in losses and generation fuel costs through implementing the split. Loads were scaled to reflect the 2011 forecast load.

A slack bus was placed at Bunnythorpe to supply the additional load. Constraints on Arapuni generation were met by additional thermal generation at Huntly.

Arapuni generation was varied to determine the maximum generation that would allow a five minute off load time on the Arapuni–Hamilton circuits during a Hamilton-Whakamaru contingency.

The Arapuni split was then opened and Arapuni generation was varied to determine the maximum generation that would allow a five minute off load time on the Arapuni–Hamilton circuit during an Arapuni–Hamilton contingency.

The constrained off generation has conservatively been valued at $20/MWh.

Losses were calculated for every hour, using the 2010 Arapuni dispatch, with the Arapuni split both open and closed.

Losses have also been conservatively valued at $20/MWh.

4.2 Unserved energy

The probabilities of forced outages on the circuits from Tarukenga to Arapuni were calculated from historic fault records.

The Arapuni split will be in place between 6am and 9pm on weekdays (i.e. 75 hours per week or 45% of the time).

Auto-reclose functionality on the line protection relays at Arapuni, Kinleith and Tarukenga will be turned off when the split is in place. This is to prevent line protection relays attempting auto-reclose when the Arapuni generating units on the 'south' bus are out of synchronism with the rest of the power following trippings of both Arapuni–Kinleith circuits or both Kinleith–Lichfield–Tarukenga circuits.

4.2.1 Loss of both Arapuni–Kinleith circuits

The Arapuni–Kinleith circuits do not seem to have any history of double circuit faults in the last twenty years. The circuits average 1.2 trips per year. If we assume that a line patrol takes three hours on average then the risk of the second circuit tripping before the first circuit has been restored is 1.2 faults per year x 3 hours of risk/24 hours per day/ 365 days per year = 0.0004 per year – which corresponds to a return period of around 2400 years.

The Arapuni–Kinleith circuits do have a history of sequential outages where one circuit is forced out of service followed by the remaining circuit being forced out of service a few minutes later. This occurs about once every five years on average.

The consequence of both Arapuni–Kinleith circuits being out of service at the same time the Arapuni split is in place is the loss of Arapuni 'south' bus generation which would need to be made up from generation elsewhere. It is likely some load at Kinleith will be lost following the tripping of both Arapuni–Kinleith circuits due to a drop in voltage but this loss would occur regardless of whether the Arapuni bus split is in place.

Assuming maximum Arapuni 'south' bus generation at the time when the Arapuni–Kinleith circuits are tripped, additional generation fuel cost to replace the lost generation is \$60/MWh and 0.25 hours to restore connection, the expected costs per year are 45% (time split is in place) x 0.2 consecutive trippings per year x 68 MW x 0.25 hours x \$60/MWh = \$91 per year.

4.2.2 Kinleith–Lichfield–Tarukenga circuits

The Kinleith–Lichfield–Tarukenga circuits do not seem to have any history of double circuit faults in the last twenty years. The circuits average 2.3 trips per year. If we assume that a line patrol takes three hours on average then the risk of the second circuit tripping before the first circuit has been restored is 2.3 faults per year x 3 hours of risk/24 hours per day/ 365 days per year = 0.0008 per year – which corresponds to a return period of around 1250 years.

The Kinleith–Lichfield–Tarukenga circuits do have a history of sequential outages where one circuit is forced out of service followed by the remaining circuit being forced out of service a few minutes later. This occurs about once every twenty years on average.

The consequence of both Kinleith–Lichfield–Tarukenga circuits being out of service at the same time the Arapuni split is in place is:

- Loss of Arapuni 'south' bus generation; and;
- Loss of all load at Kinleith and Lichfield.

The loss of load and generation may be smaller if the Arapuni and Kinleith generation and Kinleith load can successfully form an island.

The cost of both Kinleith–Lichfield–Tarukenga circuits tripping when the split is in place is:

- The loss of generation at Arapuni on the south bus which would need to be made up from generation elsewhere; and;
- Energy not served at Kinleith and Lichfield.

It is assumed that following the tripping of both circuits, supply to Kinleith and the Arapuni south bus can be restored quickly by closing the Arapuni bus split.

Assuming maximum Arapuni 'south' bus generation at the time when the Arapuni–Kinleith circuits are tripped, additional generation fuel cost to replace the lost generation is \$60/MWh and 0.5 hours to restore connection, the costs per year are 45% (time split is in place) x 0.05 consecutive trippings per year x 68 MW x 0.5 hours x \$60/MWh = \$46 per year.

Assuming load reduction of 100 MW at Kinleith following the loss of the Arapuni 'south' bus generation, 0.5 hours to restore connection, a VOLL of \$20000/MWh, the energy not served costs are 45% (time split is in place) x 0.05 consecutive faults per year x 100 MW x 0.5 hours x \$20000/MWh = \$22300 per year.

The load reduction at Lichfield is not considered as this load will be lost regardless of whether the 110 kV bus at Arapuni is split if both Kinleith–Lichfield–Tarukenga circuits are tripped.

5 Costs

The applicable costs for this cost benefit analysis are shown in the Table below.

Cost	Value ($M)	Comment
the direct labour and material costs incurred by Transpower and the designated transmission customers	0.1	This is the cost of physically reconfiguring the Arapuni 110 kV bus.
any increase in the estimation of expected unserved energy	0.03	
Changes in generator fuel cost	0.001	
Total	**0.131**	

6 Benefits

The applicable costs for this cost benefit analysis are shown in the Table below.

Benefit	Value ($M)	Comment
any reduction in fuel costs incurred by a generator	$2.3	The split allows an additional 114,000 MWh to be generated from Arapuni power station over a year. The average reduction in fuel cost (fuel cost of generation that would otherwise be required less the Arapuni fuel cost) is assumed to be at least $20/MWh.
changes in losses, including local losses:	0.04	Reduction in losses over a year is 2242 MWh.
Total	**$2.34**	

7 Discussion and Conclusions

The amount of analysis conducted for the net benefit should be commensurate with the value of the investment. In this case the value of the investment is around $100,000 (the cost of reconfiguring the Arapuni bus). What we need to show is that the benefits are likely to be at least an order of magnitude greater than the cost.

There are some caveats on this analysis:

- The net benefit test should be reviewed following the commissioning of the new 400 kV-capable line to Auckland;
- The hydrology of the Waikato River is not considered, generation at Karapiro and upstream may vary with the constraints at Arapuni;
- Opening the split between 6am-9pm is relatively arbitrary, there may be more economic ‘always open’ periods which further analysis might reveal.

The net benefit test for implementing a system split at Arapuni between 6am and 9pm on weekdays is positive ($2.3M benefits per year versus $0.1M cost).

Appendix B Letter from Genesis

11 Chews Lane
PO Box 10568
The Terrace
Wellington 6143
New Zealand

Genesis Power Limited
trading as Genesis Energy

Fax: 04 495 6363

24 August 2011

John Clarke
General Manager Grid Development
Transpower Limited
96 The Terrace
WELLINGTON

By email: john.clarke@transpower.co.nz

Dear John

Market Implications of Arapuni Reconfiguration

I am writing to raise concerns regarding the market implications of a proposed grid configuration change at Arapuni. Our analysis is that the change, which would be in effect between 6 am and 9 pm each weekday, will provide Mighty River Power with regular opportunities to exercise market power in the generation market should it wish to do so. If that were to occur, we would expect that would have flow on effects in the local hedge and retail markets.

Transpower has carried out a net benefits assessment of the proposed change, but our understanding is that the assessment has not considered the market implications of the change. Transpower personnel have stated that this is due to the relatively narrow set of costs and benefits prescribed in the Electricity Industry Participation Code ("**the Code**"). We consider that the Code as drafted would permit consideration of market implications, and that Transpower should not implement the grid configuration change in any event.

If Transpower decides to make the configuration change, then we consider that a Code change to require Transpower to more fully consider the market implications of grid configuration changes would be appropriate. As such, we have copied this letter to the Electricity Authority.

Genesis Energy recently submitted to the Commerce Commission that analysis of the costs and benefits of Transpower's capital expenditure should adopt a wider consideration of the competition benefits that grid expansion can bring consumers. I attach a copy of that submission for your information.

At this stage, we encourage Transpower to explicitly address the market implications of the proposed Arapuni split and to investigate whether there is an alternative approach that would achieve Transpower's security objectives without compromising competition.

If you would like to discuss any of these matters further, please contact me on 04 495 6353.

Yours sincerely

Malcolm Alexander

General Manager Corporate Affairs

Copy to:

Kieran Devine, General Manager System Operations

Carl Hansen, Chief Executive, Electricity Authority

Appendix C Transpower's revised net benefit assessment

Arapuni grid reconfiguration

In 2010 Transpower decommissioned the Arapuni-Pakuranga 110 kV circuit to allow construction of the new 400 kV capable line to Auckland. This decommissioning increased generation constraints at Arapuni required to manage post contingency loadings on the Arapuni-Hamilton circuits. A generation runback scheme at Arapuni was installed to allow greater pre-contingency generation at Arapuni.

We have identified that implementing a bus split at Arapuni will further relieve the constraints on generation at Arapuni, increase power transfer capacity into the Upper North Island on the 220 kV network and reduce system losses. This is an interim measure until the new 400 kV capable line to Auckland is commissioned. At this time the need for the split will be reviewed.

We consider the use of a bus split at Arapuni to be an acceptable interim measure similar to the use of special protection schemes for the same purpose. This is discussed in greater detail in our Transmission Code of Practice (http://www.gridnewzealand.co.nz/n4763,375.html).

We propose to implement a system split at Arapuni. The split will be normally in place but may be removed during some planned outages or during certain grid emergencies. The system split would be a permanent change in the way the grid is configured so we have applied the net benefit test which Transpower is required to carry out when permanently reconfiguring the grid.

Background

We recently reconfigured the 110 kV bus at Arapuni. This enables us to easily implement a system split at Arapuni and close that split when required. The split has three Arapuni generating units connected to the circuits to Kinleith and five generating units connected to the circuits going to Ongarue, Hangatiki, Hamilton and Bombay.

The bus split relieves constraints on generation at Arapuni power station. The installed capacity at Arapuni is 180 MW. The power station can be constrained back to 100 MW at times of very low generation in the Upper North Island. It should be noted that the bus split will not completely relieve constraints at Arapuni.

The split will also relieve the need for the System Operator to declare grid emergencies to split the system at Kinleith to manage loading on the 110 kV circuits between Tarukenga, Kinleith, Arapuni and Hamilton.

The split does require a minimum amount of generation at Arapuni from the generating units connected to Kinleith. This is to maintain security of supply to Kinleith and Lichfield and to manage voltages.

September 2011

Net Benefit Test

Section 12.117 of the Electricity Industry Participation Code requires Transpower to demonstrate a net benefit for any permanent reconfiguration of the grid. The following benefits and costs should be estimated where applicable:

- Changes in fuel costs incurred by a generator;
- Direct labour and material costs incurred by Transpower and the designated transmission customers;
- Changes in estimated maintenance costs including Transpower's and any designated transmission customer's costs;
- Any change in the estimation of expected unserved energy;
- Changes in fuel costs of existing assets, committed projects and modelled projects;
- Changes in the value of involuntary demand curtailment;
- Changes in the costs of demand-side management changes in costs resulting from deferral of capital expenditure on modelled projects;
- Changes in costs resulting from differences in the amount of capital expenditure on modelled projects;
- Changes in costs resulting from differences in operations and maintenance expenditure on existing assets, committed projects, and modelled projects;
- Changes in costs for ancillary services;
- Changes in losses, including local losses;
- Changes in subsidies or other benefits provided under or arising pursuant to all applicable laws, regulations and administrative determinations.

Methodology for analysis

Losses and generation fuel costs

We used historic load, generation, capacitor switching and voltage setpoint information for 2010 to estimate reduction in losses and generation fuel costs through implementing the split. Loads were scaled to reflect the 2011 forecast load.

A slack bus was placed at Bunnythorpe to supply the additional load. Constraints on Arapuni generation were met by additional thermal generation at Huntly.

Arapuni generation was varied to determine the maximum generation that would allow a five minute off load time on the Arapuni-Hamilton circuits during a Hamilton-Whakamaru contingency.

The Arapuni split was then opened and Arapuni generation was varied to determine the maximum generation that would allow a five minute off load time on the Arapuni-Hamilton circuit during an Arapuni-Hamilton contingency.

The constrained off generation has conservatively been valued at $20/MWh.

The analysis considered the hours between 7:00 am and 9:00 pm. This range of hours was considered as the original proposal was for having the split open during these hours only. Since, several participants have expressed the desire that the split should be permanently in place. We have not repeated carried out analysis for the hours between 9:00 pm and 7:00 am as the analysis is quite computationally intensive and will generally only add to the benefits of the bus split.

Losses were calculated for every hour, using the 2010 Arapuni dispatch, with the Arapuni split both open and closed.

Losses have also been conservatively valued at $20/MWh.

Unserved energy

The probabilities of forced outages on the circuits from Tarukenga to Arapuni were calculated from historic fault records.

Auto-reclose functionality on the line protection relays at Arapuni, Kinleith and Tarukenga will be turned off when the split is in place. This is to prevent line protection relays attempting auto-reclose when the Arapuni generating units on the 'south' bus are out of synchronism with the rest of the power following trippings of both Arapuni-Kinleith circuits or both Kinleith-Lichfield-Tarukenga circuits.

Loss of both Arapuni-Kinleith circuits

The Arapuni-Kinleith circuits do not seem to have any history of double circuit faults in the last twenty years. The circuits average 1.2 trips per year. If we assume that a line patrol takes three hours on average then the risk of the second circuit tripping before the first circuit has been restored is 1.2 faults per year x 3 hours of risk/24 hours per day/ 365 days per year = 0.0004 per year – which corresponds to a return period of around 2400 years.

The Arapuni-Kinleith circuits do have a history of sequential outages where one circuit is forced out of service followed by the remaining circuit being forced out of service a few minutes later. This occurs about once every five years on average.

The consequence of both Arapuni-Kinleith circuits being out of service at the same time the Arapuni split is in place is the loss of Arapuni 'south' bus generation which would need to be made up from generation elsewhere. It is likely some load at Kinleith will be lost following the tripping of both Arapuni-Kinleith circuits due to a drop in voltage but this loss would occur regardless of whether the Arapuni bus split is in place.

Assuming maximum Arapuni 'south' bus generation at the time when the Arapuni-Kinleith circuits are tripped, additional generation fuel cost to replace the lost generation is $60/MWh and 0.25 hours to restore connection, the expected costs per year are 0.2 consecutive trippings per year x 68 MW x 0.25 hours x $60/MWh = $204 per year.

Arapuni bus fault with split in place

A bus fault at Arapuni on the south bus (with the split in place) will result in the loss of all south bus generation. This generation will need to be made up from elsewhere. It is likely some load at Kinleith will be lost following the tripping of both Arapuni-Kinleith circuits due to a drop in voltage but this loss would occur regardless of whether the Arapuni bus split is in place.

The probability of a bus fault occurring in a year is around 0.02[1] (50 year return period).

Assuming maximum Arapuni 'south' bus generation at the time of the bus fault, additional generation fuel cost to replace the lost generation is $60/MWh and 4 hours to restore connection, the expected costs per year are 0.02 bus trippings per year x 68 MW x 4 hours x $60/MWh = $326 per year.

Kinleith-Lichfield-Tarukenga circuits

The Kinleith-Lichfield-Tarukenga circuits do not seem to have any history of double circuit faults in the last twenty years. The circuits average 2.3 trips per year. If we assume that a line patrol takes three hours on average then the risk of the second circuit tripping before the first circuit has been restored is 2.3 faults per year x 3 hours of risk/24 hours per day/ 365 days per year = 0.0008 per year – which corresponds to a return period of around 1250 years.

The Kinleith-Lichfield-Tarukenga circuits do have a history of sequential outages where one circuit is forced out of service followed by the remaining circuit being forced out of service a few minutes later. This occurs about once every twenty years on average.

The consequence of both Kinleith-Lichfield-Tarukenga circuits being out of service at the same time the Arapuni split is in place is:

- Loss of Arapuni 'south' bus generation; and;
- Loss of all load at Kinleith and Lichfield.

The loss of load and generation may be smaller if the Arapuni and Kinleith generation and Kinleith load can successfully form an island.

The cost of both Kinleith-Lichfield-Tarukenga circuits tripping when the split is in place is:

- The loss of generation at Arapuni on the south bus which would need to be made up from generation elsewhere; and;

- Energy not served at Kinleith and Lichfield.

It is assumed that following the tripping of both circuits, supply to Kinleith and the Arapuni south bus can be restored quickly by closing the Arapuni bus split.

Assuming maximum Arapuni 'south' bus generation at the time when the Arapuni-Kinleith circuits are tripped, additional generation fuel cost to replace the lost generation is $60/MWh and 0.5 hours to restore connection, the costs per year are 0.05 consecutive trippings per year x 68 MW x 0.5 hours x $60/MWh = $102 per year.

Assuming load reduction of 80 MW at Kinleith following the loss of the Arapuni 'south' bus generation, 0.5 hours to restore connection, a VOLL of $20,000/MWh, the energy not served costs are 0.05 consecutive faults per year x 80 MW x 0.5 hours x $20,000/MWh = $40,000 per year.

[1] See the System Operator Credible Event Management Review (http://www.systemoperator.co.nz/f2531,21144591/REPORT_-_Credible_Event_Management_Review_For_Consultation.pdf).

The load reduction at Lichfield is not considered as this load will be lost regardless of whether the 110 kV bus at Arapuni is split if both Kinleith-Lichfield-Tarukenga circuits are tripped.

Costs

The applicable costs for this cost benefit analysis are shown in the Table below.

Cost	Value ($M)	Comment
the direct labour and material costs incurred by Transpower and the designated transmission customers	0.1	This is the cost of physically reconfiguring the Arapuni 110 kV bus.
any increase in the estimation of expected unserved energy	0.04	
Changes in generator fuel cost	0.006	
Total	**0.156**	

Benefits

The applicable costs for this cost benefit analysis are shown in the Table below.

Benefit	Value ($M)	Comment
any reduction in fuel costs incurred by a generator	$3+	The split allows more than 149,000 MWh additional output to be generated from Arapuni power station over a year. The average reduction in fuel cost (fuel cost of generation that would otherwise be required less the Arapuni fuel cost) is assumed to be at least $20/MWh.
changes in losses, including local losses:	0.04	Reduction in losses over a year is 1951 MWh.
Total	**3+**	

Other costs and benefits

Two to three generating units are required to be generating on the south bus at Arapuni when the bus split is in place. The units are required to manage loading of Kinleith Tarukenga circuit 1, maintain voltages at Kinleith within an acceptable range following the outage of one of the Kinlieth-Tarukenga circuits and to ensure that there is sufficient fault current for protection relays at Arapuni to operate correctly. Around 60 MW of generation on the south bus is required at peak times.

Concern has been expressed at the need for this south bus generation. It is perceived that the bus split has required this generation to be “constrained on” and that competition in the area has been reduced.

The Arapuni bus split increases the capacity of the 220 kV network to transfer power into the Upper North Island. At peak times, the bus split can reduce reliance on regional generation by up to 370 MW.

While 60 MW of generation is "constrained on" at Arapuni, the bus split reduces the amount of generation "constrained on" in the Upper North Island by 370 MW. In terms of competition, the bus split is very likely to improve net competition in New Zealand.

Discussion and Conclusions

The amount of analysis conducted for the net benefit should be commensurate with the value of the investment. In this case the value of the investment is around $100,000 (the cost of reconfiguring the Arapuni bus). What we need to show is that the benefits are likely to be at least an order of magnitude greater than the cost.

There are some caveats on this analysis:

- The net benefit test should be reviewed following the commissioning of the new 400 kV-capable line to Auckland;
- The hydrology of the Waikato River is not considered, generation at Karapiro and upstream may vary with the constraints at Arapuni.

The net benefit test for implementing a system split at Arapuni is positive ($3M+ benefits per year versus $0.16M cost).

Appendix D Customer advice notice about Arapuni split

TRANSPOWER SYSTEM OPERATOR

Customer Advice Notice

To:	CAN NZ Participants	**From:**	The System Operator
Sent:	23-sep-2011 10:43	**Telephone:**	0800 488 500
Ref:	641710795	**Facsimile:**	07 843 7176

Revision of:

Reoffer on the Arapuni 110kV bus

In 2010 Transpower decommissioned the Arapuni–Pakuranga 110 kV circuit to allow construction of the new 400 kV-capable transmission line to Auckland. This decommissioning increased the generation constraints at Arapuni required to manage post-contingency loadings on the Arapuni–Hamilton circuits. A generation runback scheme at Arapuni was installed to allow greater pre-contingency generation at Arapuni.

Transpower has identified that implementing a bus split at Arapuni will further relieve Arapuni generation constraints and also reduce system losses. Implementation of the split is expected to be an interim measure until the new 400 kV-capable line to Auckland is commissioned. When that line is commissioned the need for the split will be reviewed.

From **Thursday 29th of September at 10:00** The Arapuni 110kV bus will be split with ARI CB48 open.

CB48 may be closed to close the split as required for:

1. Planned Outages
2. Grid Emergencies

...

A revision of this notice will be issued if there is any change to the situation above.

Transpower New Zealand Ltd • The National Grid

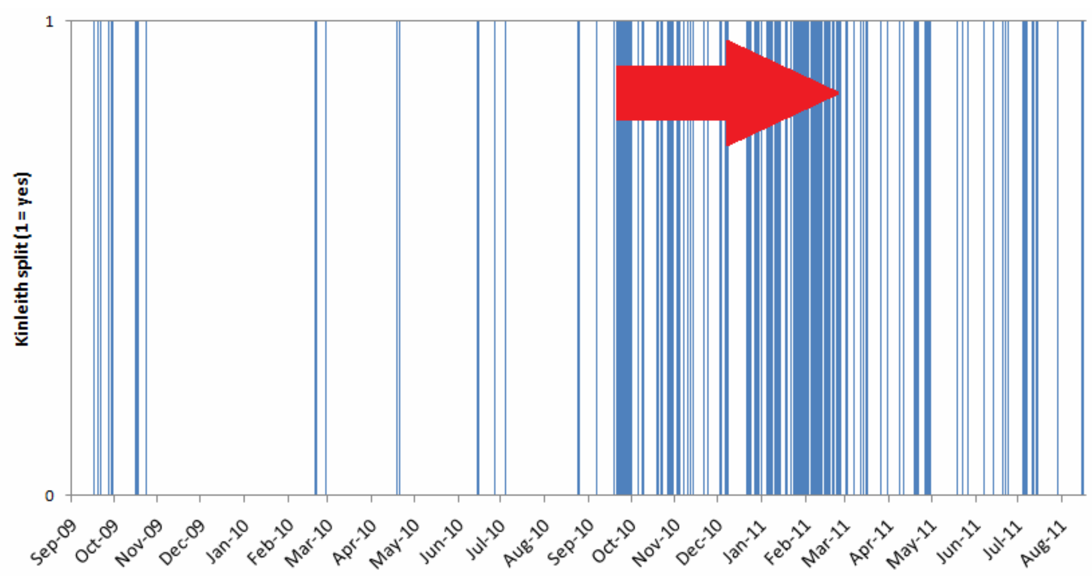
Appendix E Impact of Kinleith split

E.1 The system operator has increasingly used the split at Kinleith to manage the 110kV binding constraints on the Kinleith-Tarukenga lines for a trip of the Hamilton-Whakamaru line. Figure 13 provides an illustration of the increased frequency of usage of the split at Kinleith since September 2010.

E.2 Implementing the split at Kinleith alleviates the post-contingency overloads on the Kinleith-Tarukenga circuits due to a trip of the 220kV circuits. This reconfiguration enables additional transfer across the 220kV system into the UNI region. However, it potentially reduces the security of supply to loads at Kinleith, particularly when the Kinleith co-generation is on outage. The preference of the system operator was to split the system at Arapuni, however some additional work was needed before this could be implemented.

E.3 Transpower have indicated that the split at Arapuni will relieve the need for the system operator to declare grid emergencies and split the system at Kinleith (in order to manage the 110kV transmission constraints between Tarukenga, Kinleith, Arapuni and Hamilton). This would improve the security of supply to the loads at Kinleith, provided some minimum level of generation is offered from Arapuni at the ARI1101 market node.

Figure 13 Indication of system splits implemented at Kinleith (Sep 09 – Aug 11)



Source: Wholesale Information Trading System (WITS)

Appendix F Additional letter from Genesis

11 Chews Lane
PO Box 10568
The Terrace
Wellington 6143
New Zealand

Genesis Power Limited
trading as Genesis Energy

Fax: 04 495 6363

19 September 2011

John Clarke
General Manager Grid Development
Transpower Limited
96 The Terrace
WELLINGTON

By email: john.clarke@transpower.co.nz

Dear John

Market Implications of Arapuni Reconfiguration

Thank you for your response of 30 August 2011 to our concerns regarding Transpower's proposal to implement a permanent bus split at Arapuni. In our initial letter, we wrote the following:

> At this stage, we encourage Transpower to explicitly address the market implications of the proposed Arapuni split and to investigate whether there is an alternative approach that would achieve Transpower's security objectives without compromising competition.

In response, you pointed to the challenges of quantifying competition benefits in the wholesale market. We acknowledge that quantifying competition benefits would be challenging; however we consider that it should be relatively straightforward for Transpower to develop a market impact analysis that helps stakeholders to develop an informed view of the merits of various options. To assist with this, we asked Castalia to prepare the attached paper that illustrates how such an analysis could be developed.

As well as illustrating how a market impacts analysis could be approached, Castalia's analysis indicates that the proposed bus split in Arapuni would place Mighty River Power in a pivotal position with respect to the Kinleith and Lichfield grid exit points at least 15% of the time. At these times, Mighty River Power would have the ability to unilaterally set prices in that market. Regardless of whether Mighty River Power chooses to make use of this ability, the heightened risk should be expected to have a dampening effect on retail and hedge competition in that market and this should be expected to raise prices.

Transpower has assessed the benefit of the Arapuni bus split at around $2.3 million based on an assumption that thermal generation north of Arapuni will be displaced by generation that is around $20 per MWh cheaper. In contrast, if Mighty River Power were to raise its offers by $500 per MWh when it was pivotal, then this would raise wholesale purchasing costs by $8.6 million. This is without considering the additional opportunities provided by virtue of Arapuni operating under block dispatch. Mighty River Power would only need to raise its offers when pivotal by $134 per MWh to offset the benefits that Transpower has assessed. Clearly, market impacts have the potential to outweigh other considerations.

We remain very concerned with the proposed bus split and with Transpower's process. We do not consider that the full range of affected parties is being provided with clear information that would enable them to appreciate the relative merits of the various options available.

Given our concerns, we intend to develop and promote a Code change that would require Transpower to pursue a more robust process in future. We consider that this process should have the following features:

- *complete and accessible information* – Transpower's analysis fails to provide sufficient information to allow stakeholders to understand the tradeoffs between different options. There is no discussion of the potential market implications of the various options and it is not clear that a full range of options has been presented. The analysis that Transpower has completed appears largely targeted at a technical audience and would not be accessible to most stakeholders; and

- *open and transparent process* – the current process has relied on Transpower's "customer advice notice" channel to reach affected parties in the first instance. Transpower's process subsequently seems to have focussed on a self-selected group of interested parties with limited ongoing communication with other stakeholders. Transpower invited feedback on its initial analysis but has not published any of the feedback it received.

We are disappointed that Transpower has not so far been willing to treat the market impacts of its proposed changes seriously. We encourage Transpower to present stakeholders with better information and to fully consider whether it can devise an alternative option that avoids significantly adverse market impacts in Kinleith, Lichfield and Tokoroa.

If you would like to discuss any of these matters further, please contact me on 04 495 6353.

Yours sincerely

Malcolm Alexander

General Manager Corporate Affairs

Copy to:

Carl Hansen, Chief Executive, Electricity Authority

Kieran Devine, General Manager System Operations

Framework for Considering Market Impacts of Grid Changes

September 2011

1 Introduction

This note presents a framework for considering the market impacts of changes in New Zealand's transmission grid—specifically grid reconfigurations and investments. The framework recognises that grid changes will have impacts in competitive markets for supplying electricity, and that these changes should be considered as part of any decision to make a grid change. We use Transpower's current proposal to reconfigure the grid at Arapuni to show how the framework can be used to identify and describe market impacts.

Market impacts and competitive dynamics are inherently difficult to model and estimate. The actual impacts of grid changes will depend on the conduct of market participants and the strategic interactions between market participants. The framework presented here does not attempt to model these strategic interactions. In our view, the best approach is to describe how market dynamics could be altered as a result of the grid change, and to consider changes in simple market metrics—such as the proportion of time that any one market participant is able to set prices. This will help interested stakeholders identify the trade-offs involved in proposed grid changes, and provide meaningful comments on grid change proposals.

2 How Grid Changes Alter Competitive Markets

The transmission grid is widely acknowledged to alter the dynamics in competitive markets for the supply of power (wholesale spot and hedge markets, and retail markets). There are three dimensions to competitive markets that can change as a result of a change in the grid:

- **Market geography.** The transmission grid allows generators to compete to supply load at certain locations. A change in the grid can enable generators to compete in new areas, and can restrict the ability of generators to compete at certain locations.
- **Timing.** Market impacts arising from grid changes can be more or less pronounced at different times of the day, during different seasons, and under different hydrological conditions.
- **Functional markets.** Market impacts from changes in the grid are not limited to the wholesale spot market. Hedge and retail markets can also be affected if the level of risk involved in competing in those markets changes as a result of the grid change.

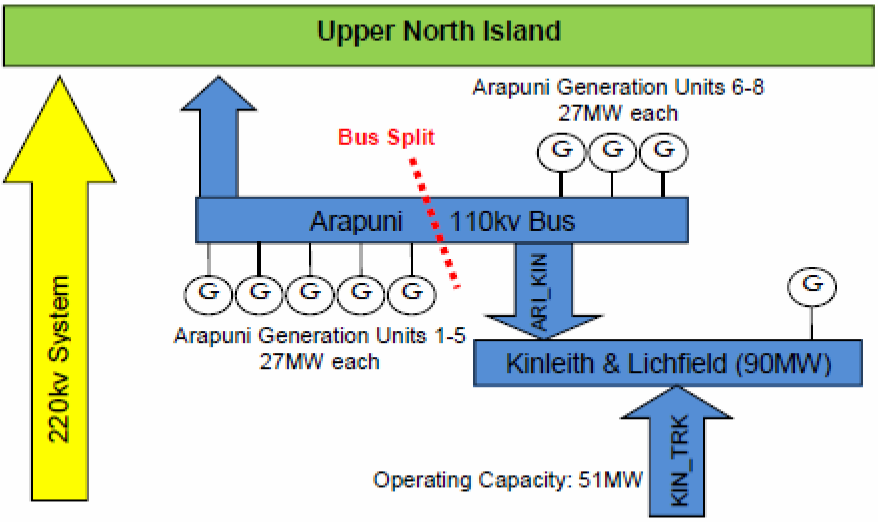
Considering proposed grid changes against these three dimensions of competitive markets provides a template for assessing any market implications arising from a grid change proposal.

3 Example: Arapuni Bus Split

Transpower has proposed to reconfigure the 110kV system by splitting the Arapuni 110kV bus. The purpose of this reconfiguration is to enable more northward transmission on the 220kV system with additional generation from Mighty River Power's Arapuni power station. Splitting the bus will mean that five Arapuni units will be connected to the northbound 110kV circuits, and the remaining three units will be connected to the southbound ARI_KIN circuit.

The effect of the proposed grid reconfiguration is shown in Figure 3.1 (a simplified representation of the high voltage transmission system around Kinleith). The 220kV (yellow) system runs in parallel to the 110kV system (blue) to supply demand in the upper North Island. Currently, Kinleith and Lichfield can be supplied from Bay of Plenty via the Kinleith to Tarukenga 110kV circuits (KIN_TRK) or from the north via the Arapuni to Kinleith 110kv circuits (ARI_KIN). There is also 40MW of local generation at the Kinleith Mill to supply demand in Kinleith and Lichfield. This generation typically follows the mill's processes (and hence demand) and is consumed entirely by the mill.

Figure 3.1: Overview of Grid Change at Arapuni



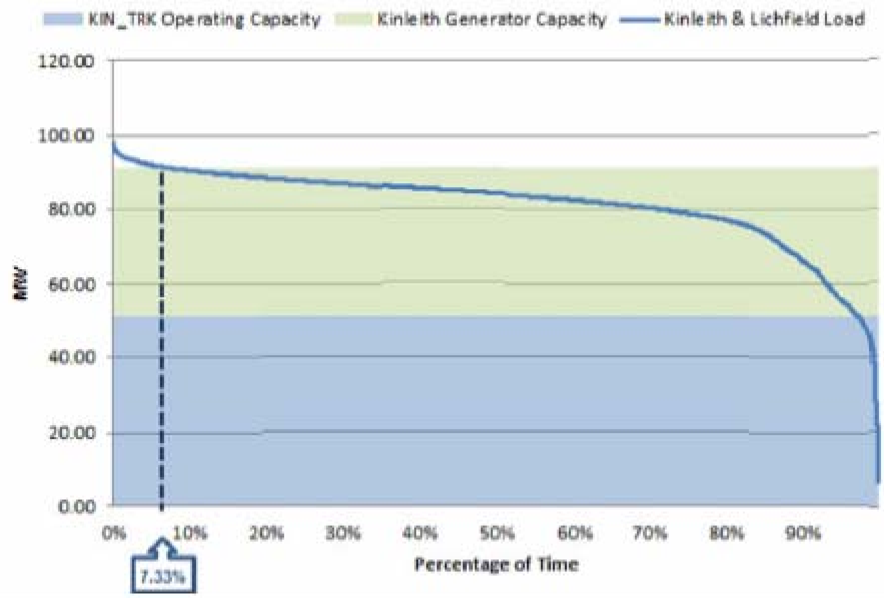
Implementing the split would result in an immediate change in market dynamics.

- **Status quo.** Arapuni does not currently have any ability to set the price at Kinleith and Lichfield under normal power grid conditions because generators in the upper North Island can supply these locations via the 110kV system north of Arapuni. Arapuni generation is only pivotal to supplying Kinleith and Lichfield in rare circumstances when a significant amount of Bay of Plenty or upper North Island generation is unavailable. The System Operator is likely to reconfigure the grid in such scenarios to alleviate any severe supply issues.
- **After the bus split.** The Arapuni power station will be required to supply demand in Kinleith and Lichfield whenever demand is greater than the sum of the transfer capacity on KIN_TRK transmission line (51 MW) and the

maximum capacity of the local Kinleith generation (40 MW). This means that after the bus split, any demand at Kinleith and Lichfield exceeding 91MW will have to be supplied by the Arapuni power station.

Using demand data from 2010, Figure 3.2 shows that after the bus split the Arapuni power station will be able to set the wholesale spot price at Kinleith and Lichfield 7.3 percent of the time. This assumes that transmission and local generation capacity are available 100 percent of the time, and can therefore be considered as a lower bound on the ability of the Arapuni power station to set the price at Kinleith and Lichfield.

Figure 3.2: Load Duration Curve at Kinleith and Lichfield in 2010



During 2010, the Kinleith power station was unavailable in approximately 8.6 percent of trading periods. This significantly reduces the amount of supply independent of Arapuni generation. Without any local generation, Carter Holt Harvey can either continue running the mill as usual, or can choose to reduce its demand. The mill reduced its demand during around 12 percent of the outages in 2010. Arapuni generation was required to meet the mill's demand for the remaining 88 percent of outages, or 7.6 percent of trading periods in 2010.

Assuming similar behaviour after the bus split, we estimate that the Arapuni power station would be able to set the price 14.9 percent of the time.

4 Description of Market Implications of Arapuni Bus Split

The changes in the market dynamics as a result of the Arapuni bus split are summarised in Table 4.1across the three dimensions of competitive markets described above.

Table 4.1: Description of Market Implications of Arapuni Bus Split

Dimension	Description	Impact of Arapuni Bus Split
Market geography	▪ Changes in grid configuration can change the ability for market participants to compete at different locations ▪ Grid investments can change the ability for market participants to compete at different locations	▪ Will relieve constraints on the northbound 110kv system from Arapuni, as well as the parallel northbound 220kv system. This will enable more transmission of low-cost generation to the upper North Island and improve competition in that region. ▪ Will significantly reduce competition for supply to Kinleith and Lichfield. When the combined load at these locations exceeds the capacity from other supply points (91MW), Mighty River Power will be able to set the wholesale price unilaterally.
Timing	▪ Market impacts arising from changes to grid configuration or grid investments can be more or less pronounced at different times, seasons, and under different hydrological conditions	▪ Market impacts will occur during peak consumption periods, typically over winter. At these times, the Arapuni station is more likely to be pivotal to supplying Kinleith and Lichfield after the split. Using 2010 data, we estimate that Arapuni generation would be required to meet demand in Kinleith and Lichfield at least 7.3 percent of the time. When the local generator at Kinleith is unavailable, Arapuni is more likely to be pivotal (actual position will depend on demand response at Kinleith). Although planned outages typically take place when demand is low, forced outages can occur any time. Using 2010 data, we estimate that Arapuni generation would be required to meet demand at least 14.9 percent of the time (assuming the same demand response at Kinleith).
Functional markets	▪ Market impacts from changes in grid configurations and grid investment are not only limited to the wholesale market. The hedge and retail markets are also affected.	▪ Mighty River Power's Arapuni station can set wholesale spot price in Kinleith and Lichfield for significant periods in a year. This reduces competition in the hedge market because other hedge sellers face significant price risks. ▪ Retail competition is also reduced. Mighty River Power's ability to set spot prices at Kinleith and Lichfield provides them a distinct competitive advantage in the region. Competitors will not want to be a net purchaser of energy at Kinleith and Lichfield.

4

In addition to these observations on the bus split, there are some unique considerations that arise in this case because the Arapuni power station is one of eight hydro stations owned by Mighty River Power that operate under block dispatch. This could expand the opportunities provided by the Arapuni bus split for Mighty River Power to set prices.

5 Accessibility

Information about the market implications of grid changes is relevant to a range of stakeholders, many of whom would not have the resources to interpret complex technical information. As such, from a process point of view, it would be desirable to present information about market implications in a clear and accessible form.

The framework developed here should support this objective. Ideally, it should be possible to develop a one or two page summary sheet template that includes the following information:

- **Grid schematic.** This should be in a simplified form similar to Figure 3.1 and should allow people to easily understand the relevant geography the subsequent market impact analysis.
- **Market participant analysis.** In the Arapuni case, it would be useful to identify the affected generator, any major users (Fonterra and Carter Holt Harvey), and the participants in the local retail market. Retail market information could be presented as a pie chart to provide an indication of existing retail market concentration.
- **General market implications analysis.** This could be presented in a form similar to Table 4.1, with more detailed supporting analysis provided separately.
- **Unique considerations.** Information such as whether the affected generator operates under block dispatch should also be provided.

Appendix G Letter from Vector

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23 September 2011

Graeme Ancell
Planning and Development Manager
Transpower
WELLINGTON

cc John Clarke
General Manager Grid Development
Transpower
WELLINGTON

cc Carl Hansen
Chief Executive
Electricity Authority
WELLINGTON

Dear Graeme,

Bus split at Arapuni

1. Vector has some comments about the bus split at Arapuni, and the net benefit test Transpower has undertaken to justify the split. No part of letter is confidential and we are happy for it to be publicly released.

2. Vector fully supports Transpower's initiative to resolve constraints that limit the amount of power that can be supplied from the south of the Upper North Island to meet Auckland and Northland demand. This, as Transpower has noted, should have positive impacts on competition in the Auckland region.

3. Vector is concerned though that competition impacts have not been identified or considered in the net benefit analysis. Vector believes the competition benefits identified by Transpower for the Auckland region, and the negative impact Genesis and Castalia suggest for Tokoroa and surrounding areas should be taken into consideration.

4. Vector would expect that any net benefit test should take into account all material costs and benefits, including those associated with the increase or decrease in the competitiveness of the electricity market. Transpower should attempt to identify options that avoid or mitigate any adverse competition impacts, where practicable. Transpower should only introduce options that have adverse competition impacts where these are shown to have the highest net benefit. The net benefit test will not be meaningful if it does not take into all material costs and benefits of Transpower's proposal.

5. While clause 12.117(2) of the Electricity Industry Participation Code does not explicitly require competition benefits to be taken into account, it does not preclude them from being taken into account in the net benefit test either.

6. We appreciate that competition impacts can be difficult to calculate, however the analysis provided by Castalia, in its Framework for Considering Market Impacts of Grid Changes, September 2011, provides a useful framework. Transpower should also be mindful that it may want or need to factor in competition benefits when it is seeking investment approval from the Commerce Commission under sections 54R and S of the Commerce Act. It would be desirable for Transpower to ensure a consistent approach to investment analysis.

7. This issue highlights that it may be desirable for the Electricity Authority to amend clause 12.117 (subpart (2), in particular) to remove any doubt that competition impacts, to the extent they are relevant, and any other material impacts, must be taken into account in any net benefit tests, not just the direct costs and benefits (such as fuel costs).

8. We trust that this letter is helpful. Vector would like to ensure the electricity market is operated in such a way that competition can be relied on, to the extent possible, to promote the long-term interests of consumers. Transpower as an access provider for generators and load has a strong interest in encouraging such outcomes.

9. If Transpower has any queries regarding Vector's views or would like further information please contact Robert Allen, Senior Regulatory Advisor, on 04 803 9036 or robert.allen@vector.co.nz.

Kind regards

RBGirdwood

Bruce Girdwood
Regulatory Affairs Manager

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
Authority	Electricity Authority
CAN	Customer Advice Notice
Code	Electricity Industry Participation Code 2010
Genesis	Genesis Power Limited (trading as Genesis Energy)
GXP	Grid exit point
MRP	Mighty River Power Limited
Regulations	Electricity Industry (Enforcement) Regulations 2010
SPD	Scheduling, Pricing and Dispatch
UNI	Upper North Island