SYSTEM OPERATOR

Manawatu wind generation

Observed impacts on the scheduling and dispatch processes

Second revision
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TRANSPOWER

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Executive Summary

1.1 Background

The integration of large scale wind generation into power systems is a challenge facing regulators, system operators and grid owners worldwide. Wind and other forms of intermittent generation have quite different characteristics to the forms of generation around which power system operation and electricity markets have been designed. In addition, the challenge of integrating large scale wind generation into New Zealand power system is compounded by three factors:

- The New Zealand power system has no interconnections to other power systems and can not draw upon other power systems' resources.
- The long and stringy nature of the New Zealand power system (generation and load are connected by long transmission lines).
- The nature of the wind resource in New Zealand (gusty and concentrated in certain areas rather than even flows and diversely spread across the country).

The Electricity Commission has instigated two initiatives to meet the challenge of integrating large scale wind generation. These are:

1. *The Wind Generation Investigation Project (WGIP).*
   The objective of the WGIP is to
   - identify and quantify the technical and electricity market impacts of wind generation upon the New Zealand power system over the next ten years;
   - Recommend (if and as required) amendments to the Electricity Governance Rules and other relevant arrangements / processes to ensure power system security and market outcomes are achieved that are consistent with the Government Policy Statement on Electricity Governance (GPS) and Commission's Principal Objectives and Outcomes; and
   - Recommend an implementation plan for proposed changes, to the extent that this is required.

   This is a long term project and as a result the rule changes identified by the WGIP are expected to take two years to implement.
2. *The Tactical Project*.
   The Tactical Project has two objectives. The first objective is an assessment of the impact of the Manawatu wind generation on scheduling and dispatch. The second objective is to identify and recommend any necessary rule changes required to accommodate the integration of wind generation into the New Zealand power system for the interim period before the WGIP is completed.

The process for the first part of the Tactical Project (for which this report is the culmination) has been to:

- assess the impact of Manawatu Wind Generation on scheduling and dispatch for November and December 2004 and publish a report. This report was published in March 2005,
- continue the analysis for the period January to April 2005,
- consult informally with Meridian Energy Limited and Trustpower on the outcome of analysis,
- publish a revised report in September 2005. (This report).

The process for the second part (to identify any necessary rule changes for the interim period) is to:

- request information (via the Electricity Commission consultation framework) to identify possible rule changes. This consultation was carried out in July-August 2005,
- identify the necessary rule changes and propose recommendations to the Electricity Commission. This is expected to be completed in October 2005.

1.2 The integration of large scale wind generation into power systems

Wind and other forms of intermittent generation are quite different to the forms of generation around which power systems have evolved. Conventional hydro and thermal generation plant has the ability to control its output by adjusting its fuel input. Such generating units can maintain a set level of power output by adjusting the fuel input. The power output of conventional hydro and thermal generation is largely predictable and constant.

Wind generation can not control its power output in such a way – it is dependent on the wind that is blowing at the time. This has some implications for power system and electricity market operation which has been designed around predictable and constant generation.

When the level of wind generation penetration is small, the effects of its unpredictability and variability make little impact on the power system. However, with increasing amounts of wind generation connected to the power system, there comes a point where the impacts of unpredictability and variability of wind generation become significant for the operation of the power system.

This report analyses the impact that the unpredictability and variability of the Manawatu wind generation output has had upon the operation of the New Zealand power system and upon scheduling and dispatch during the period between November 2004 and April 2005.

1.3 Scope of this report

The analysis of the impact of the Manawatu Wind Generation on scheduling and dispatch has been limited to the areas of:

- quantifying the physical impact upon the operation of the frequency keeping ancillary service
- quantifying the impact on the accuracy of wind generation and load forecasts
- quantifying the impacts of changes in power flows across the grid following a change in wind generation output, and
- a discussion of possible mitigating measures.

The assessment of market costs relating to Manawatu wind generation variability and the effect of the wind generation on electricity prices and participant behaviour are not in the scope of this report.

The report only considers impacts on the power system that have been observed to date. There are other power system issues (which have been observed elsewhere) that will need to be further investigated. These issues include:

- the effect of wind farms on the dynamic behaviour of the power system (e.g. possible impacts arising from the reduction in system inertia and the extent to which the impact of wind farms on the dynamic performance of the power system can be modelled);
- the effect on voltage control of the grid when large scale wind farms substitute for conventional generation; and
- possible impacts arising from reduction in fault levels, particularly on the operation of the HVDC link.

1.4 Manawatu Wind Generation

There are two existing wind farm sites in the Manawatu region – Tararua wind farm owned by Trustpower Limited and Te Äpiti wind farm owned by Meridian Energy Limited. Figure E.1 shows the lower North Island and the Manawatu region. The Tararua wind farm is embedded behind the Linton and Bunnythorpe grid exit points and has been in operation since 1999. The Te Äpiti wind farm is connected to the grid near Woodville and was fully commissioned in late 2004. The combined installed capacity of the two wind farms is over 150 MW (around 90% of the total installed wind generation capacity in New Zealand).

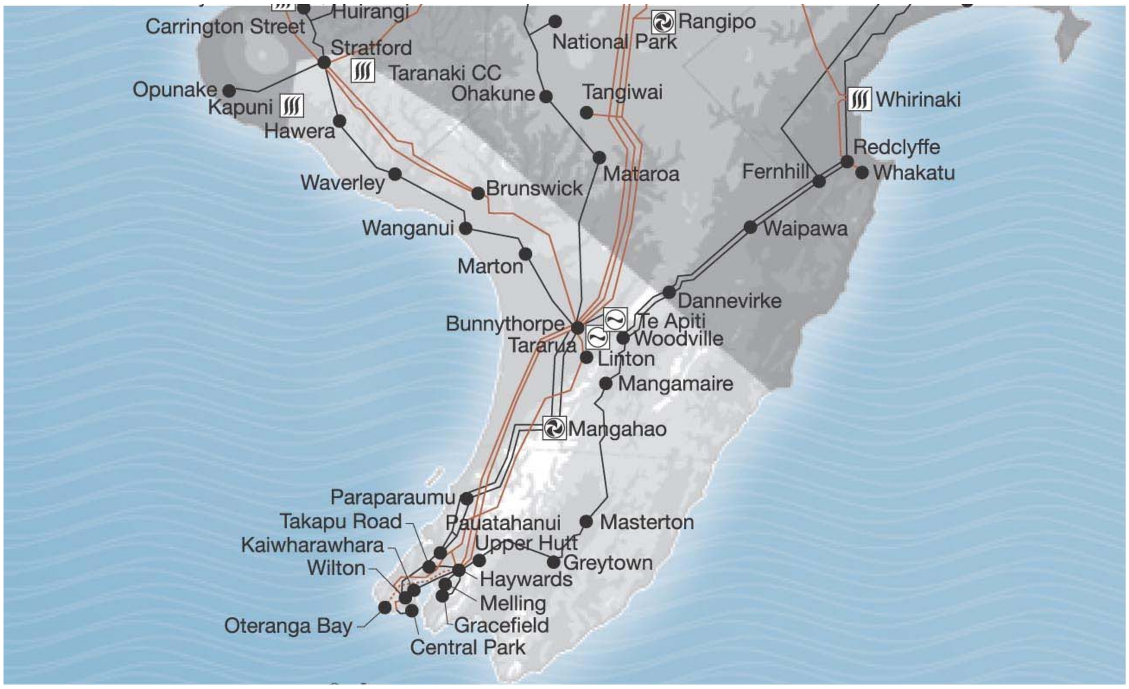

Figure E.1 – Lower North Island

This report focuses on the impact of the combined Manawatu wind generation for the period between November 2004 and April 2005.

1.5 Manawatu Wind Generation Output variability

The amount of generation output from the two wind farms in the Manawatu region has been observed to vary significantly over a day. This variability makes the forecasting of future amounts of wind generation difficult. There have also been a number of large generation changes within short time periods. Managing these large changes in output in real time can pose operational difficulties.

Figure E.2 shows the number of observed changes in combined Manawatu wind generation output of above 25 MW over five minutes for the period December 2004 to March 2005, plus events greater than 50 MW over five minutes for November 2004. It should be noted that six months is not long enough to observe all events that might occur. Further observation is required to confirm the probability of the occurrence of sudden large events in Manawatu wind generation output.

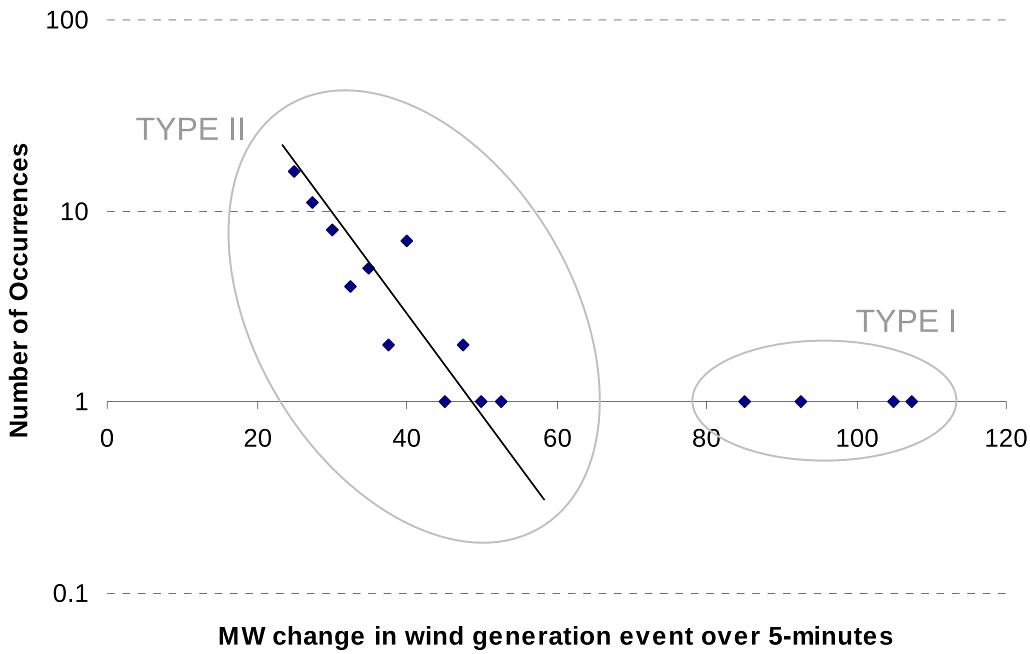

Figure E.2 – Number of observed changes in Manawatu wind generation output as a function of size (MW)

Figure E.2 suggests that there are two apparent types of sudden change in the amount of generation output. The first type of sudden change (Type I) seems to occur during certain specific weather conditions, which are discussed in detail in Section 3.1.2 in the main body of the report. The average size of these events is around 100 MW which is roughly equivalent to 66% of the currently installed wind generation capacity in the Manawatu region. Based on observations to date, it is expected that around 10 events of this type will occur each year. It is possible that this type of change is a result of weather conditions unique to the location of wind farms in the Manawatu region.

The second type of sudden change (Type II) is smaller in size and seems to show a correlation between the number of occurrences of an event and size of the sudden change in generation. It is possible that these events may reflect the natural variability of wind speeds (and hence wind generation output) in the region. Based on observations to date, it is expected that around 12 events of a change of 50 MW (33% of currently installed wind capacity) in five minutes will occur each year.

The analysis in this report indicates that the Manawatu wind generation does impact on the operation of the power system and electricity market. Of course, the behaviour of other generation and load also impacts upon the operation of the power system and electricity market. This behaviour is generally understood and accounted for in the operation of the power system and electricity market. The impact of the variability of the existing amount wind generation farms is significant and as yet not well understood. The impact of the variability of the amount of future wind generation proposed to be connected to the power system will require changes to power system operation and the electricity market.

The impacts of 150 MW of installed wind generation capacity in the Manawatu region are being already observed. There are currently 670 MW of wind generation projects in the North Island which have already gained consents or for which consents are currently being sought. The amount of wind generation capacity installed in the North Island in three to five years time could potentially be in the range of 850 MW to 1300 MW (see Section 1.10.2 later in the report).

1.6 Large changes in Manawatu wind generation output

A number of sudden large changes in the combined Manawatu wind generation output were observed during the period from November 2004 to April 2005. Analysis of the impact upon power system operation of some of these events (i.e. those where an increase or decrease of greater than 50 MW in a five minute period occurred) has been carried out.

There are two reasons why this size of event has been examined:

- A 50 MW change in five minutes equates to the minimum required frequency keeper[1] response rate of 10 MW per minute, and
- ±50 MW is the size of the dispatched frequency keeping band.

Six such events (a change of greater than 50 MW over five minutes) have been identified. These are listed in Table E.1.

Event Number	**Date and Time**	**Approximate output change and interval**
1	15 Nov 2004, 01:00 to 02:00	140MW in 13 minutes increase (105MW in 5 minutes)
2	23 Nov 2004, 23:50 to 24:00	110MW in11 minutes increase (85MW in 5 minutes)
3	30 Dec 2004, 16.45 to 17.00	130MW in 12 minutes increase (93MW in 5 minutes)
4	14 Feb 2005, 11:30 to 12:00	70MW in 12 minutes increase (53MW in 5 minutes)
5	14 Feb 2005, 14:30 to 14:45	120MW in 10 minutes increase (109MW in 5 minutes
6	25 Mar 2005, 10:50 to 11:05	70MW in 8 minutes increase (50MW in 5 minutes)

Table E.1 - List of events during November 2004 to April 2005 where there was a change of greater than 50 MW over five minutes.

[1] See Section 1.7.1.

1.7 Impacts on power system operation

1.7.1 Frequency Keeping

The System Operator manages power system frequency (nominally 50 Hz) by procuring the frequency keeping ancillary service. This ancillary service is provided by a generating station which is contracted and dispatched for that purpose. The frequency keeping station (the “frequency keeper”) in each island changes output to match changes in other generation and load in order to maintain power system frequency between 49.8 Hz and 50.2 Hz (the normal band). There is usually one frequency keeper in each island. Sudden changes in the level of Manawatu wind generation output are largely compensated by the frequency keeper until re dispatch of other generation occurs.

During each of the six events in Table E.1, the impact of the sudden change in wind generation output on the frequency keeper was analysed. It is evident that the frequency keeper compensates for this rapid change in wind generation output in each of these events.

Figure E.3 shows the effect of a sudden large event occurring on 15 November 2004 starting at around 01.00 hours on the North Island frequency keeper and on North Island frequency. The dispatched frequency keeping (band) limits are shown to illustrate when the frequency keeper has had to go outside the dispatched band (±50 MW) in an effort to maintain the island frequency.

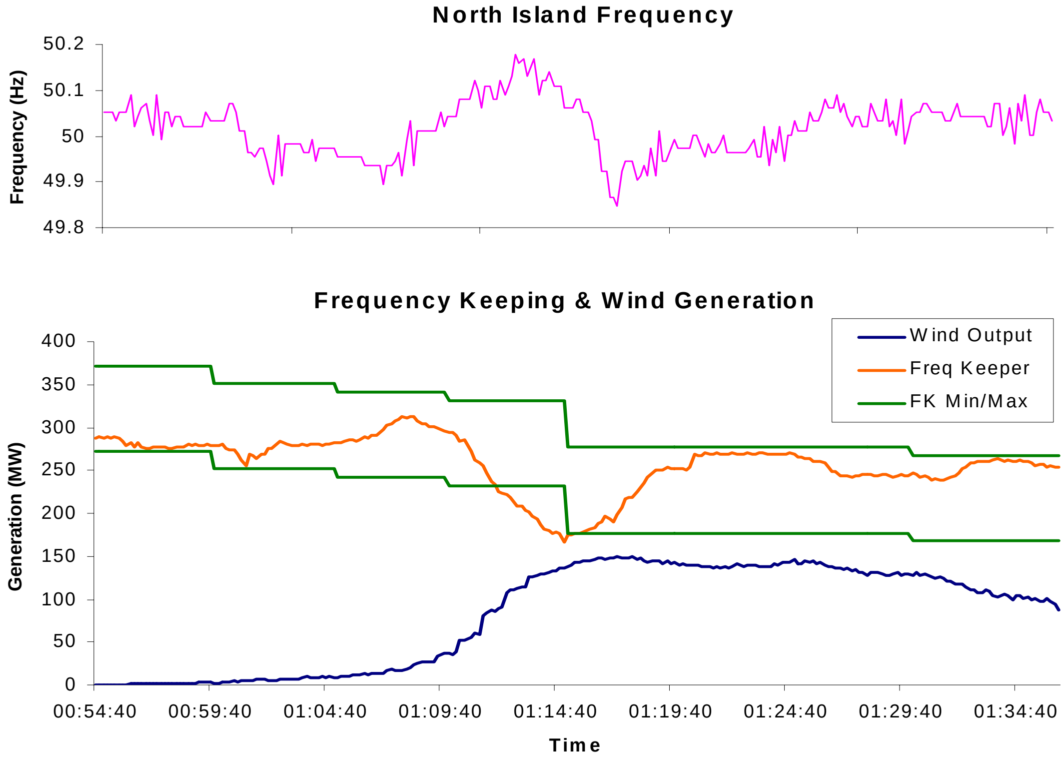

Figure E.3 -North Island frequency, frequency keeping generation (and frequency bands) in response to the event on 15 November 2004

Figure E.3 shows a rapid increase in Manawatu wind generation output from around 01:00. During this event the total wind generation output increased by 105 MW over 5 minutes and 150 MW in 20 minutes. From Figure E.3, it is evident that in the initial period nearly all of this increase in generation is offset by the frequency keeper which reduced output in response to the increase in the North Island frequency. During this time the frequency keeper moves below the dispatched frequency band and the North Island frequency moves 0.3 Hz to a peak near 50.2 Hz, the upper limit for normal frequency band.

For two of the six events (15 November 2004 and 25 March 2005) the sudden change in wind generation output resulted in the frequency keeper going outside their dispatched MW frequency keeping band. These events have an impact on North Island frequency, and on one occasion (23 November 2004) the North Island frequency moved outside the normal frequency band. Two of the events (15 November 2004 and 14 February 2005) had rates of change of output that were twice the contracted frequency keeper response rate (of 10 MW per minute), and were twice the size of the dispatched frequency keeping response band (±50 MW) at the time.

It should be noted that during five of these events frequency keeping was being provided by a hydro generation station. This type of generation plant has a high response rate in terms of frequency keeping. The high response rate of the frequency keeper combined with the response of other generating plant connected at the time meant that the impact of wind generation output increase was able to be managed with minimal impact on the power system. Thermal generation units used for frequency keeping in the North Island do not respond as quickly as hydro plant nor (normally) have adequate capacity to cover such a rapid change in generation.

More frequent re-dispatch of generation will help mitigate the impact of sudden large changes in wind generation output. In the short term, automation of the issuing of dispatch instructions (currently a manual process) can be investigated as an interim measure until a permanent solution is implemented. The need for a permanent solution is urgent given the considerable amount of wind generation that is proposed to be connected to the power system within the next three years. A high priority needs to be placed on putting in place the framework whereby a permanent solution (e.g. some form of AGC solution) can be agreed and implemented.

1.7.2 Transmission constraints

The sudden increase in wind generation output in the Manawatu region combined with a corresponding reduction in generation output by the frequency keeper causes a change in power flow within the circuits that make up the transmission grid. This change in power flow has the potential to cause some transmission circuits to exceed their stated rating until the System Operator is able to dispatch other generators to compensate for the change. Reduced power system capability limits may need to be put in place to avoid assets exceeding stated capability during a sudden change in wind generation output.

Two scenarios have been identified where the change in power flow, following a change in Manawatu wind generation output, has an effect on power system capability limits:

- High North transfer through the North Island.
  A sudden increase in Manawatu wind generation output can cause power system capability limits to be exceeded during high power transfer to the north of Bunnythorpe. The limitation is on the Tokaanu - Whakamaru circuits.
- HVDC South transfer.
  Power system capability limits can be exceeded during high power transfer to the south of Bunnythorpe during a sudden decrease in Manawatu wind generation output. The limitation is on the Brunswick - Stratford circuits and applies while summer ratings are in effect.

Further information on the effect of Manawatu wind generation on power system capability limits has been included in the July 2005 Amendment to the System

Security Forecast (http://www.transpower.co.nz/?id=4464). The deployment of automatic systems to limit or reduce win generation output when assets are at risk (i.e. runbacks or inter-trip schemes) by wind generators and the grid owner could negate the need to reduce power system limits

1.8 Impacts on the electricity market

1.8.1 Forecast accuracy

Wind generation (and other forms of intermittent generation) is not offered[2] into the electricity market in the same manner as other types of generation are offered. As part of the wind generation offer, a forecast of the amount of wind generation in a trading period is provided to the System Operator. The accuracy of the provided forecast is dependent on the wind generator's ability to predict the amount of wind generation in advance.

As part of the scheduling process, the System Operator schedules offered generation to meet forecast load. The forecasts provided by wind generators are used in the scheduling process. Inaccuracy in wind generation forecasts means that generation that is actually dispatched in a trading period can be quite different to the generation that was scheduled earlier. This has two impacts.

Impact on power system security

The System Operator uses the scheduling process to identify possible power system security issues (e.g. not enough generation offered in a particular trading period). Inaccurate wind generation forecasts can mean that generation dispatched in a trading period is quite different to the generation that was scheduled and for which power system security analysis was carried out. This increases the risk that power system security issues emerge during dispatch. This affects the System Operator's ability to manage the power system securely.

The current level of wind generation forecast accuracy is manageable within the current scheduling and dispatch processes (although the effects of forecast inaccuracy are being observed). As increasing amounts of wind generation capacity is installed, there will come a point where the inaccuracy in the wind generation (or other intermittent generation) is so large that power system security can not be safely managed using the current processes and software tools.

One option to improve the accuracy of wind generation forecasts is to consider the use of a common centralised wind generation forecast in the scheduling and dispatch process as has been implemented in other countries.

[2] It should be noted that the output of Te Apiti is the only wind generation currently offered into the electricity market. The output of Tararua North and South wind generation will be offered in the near future.

Impact on market outcomes

Pre-dispatch Generation schedules produced in the scheduling process provide information to market participants who can then adjust their offers of generation and bids of load in response to the forecast prices in the schedules. This allows generators to optimise the efficiency of their generating units and to plan starting and stopping of their plant. Price forecasts are used by purchasers to adjust their bids, for example, reducing the amount of electricity they intend to consume during future trading periods where the price is high.

Inaccuracy in wind generation forecasts affects the accuracy of the generation schedules. Generators and purchasers who use the information in the pre-dispatch schedules to plan their offers and bids will find that the actual dispatch in some trading periods is quite different to the schedule around which they based their offers and bids. This difference will result in increased plant operating costs and opportunity costs (e.g. where generators did not offer their plant based on low forecast prices but where the final prices were high).

1.8.2 Te Äpiti Forecast Accuracy

Figure E.4 shows the cumulative distribution of the two hour Te Äpiti forecast generation error for the period November 2004 to April 2005. The two hour forecast is significant in the scheduling and dispatch process as generators are not permitted to change their offers in the two hours before dispatch except for certain defined circumstances.

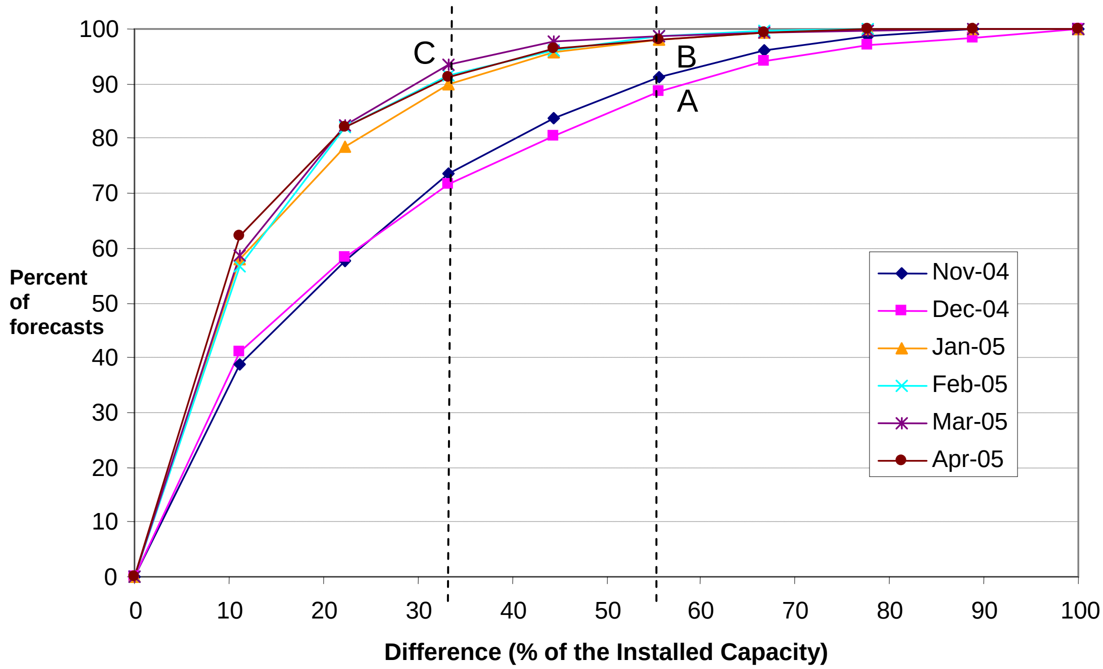

Figure E.4 - Cumulative distribution of the Te Äpiti two hour forecast generation error (for months November 2004 to April 2005).

The accuracy of Te Äpiti's two hour forecasts has improved markedly since the start of 2005. In November and December 2004, 90% of forecasts had an error of less than 55% of the installed capacity of Te Äpiti wind farm (point A on the graph). From January 2005 this has improved to 98% of forecasts (point B). However, 10% of the improved forecasts still have an error greater than 33% of the installed capacity (point C).

The pre-dispatch schedules provide important information for market participants and are used by the System Operator to assess power system security. Security assessments are carried out four times a day. Participants are notified of identified security issues enabling them to respond to such warnings and revise their bids or offers. The longer range forecasts (such as twelve hours out) are important for standby generation availability given it can take thermal units over eight hours to commit. The shorter range forecasts (such as six hours out) are important as participants will revise their offers and bids to in response to notified security issues.

While the two hour forecasts of Te Äpiti wind generation output have improved, the six and twelve hour forecast errors for Te Äpiti wind generation have not improved since the analysis carried out in November and December 2004.

1.8.3 Must Run Generation

The output of some generating units is offered into the electricity market at zero prices. The reason for doing this can be because the fuel source for the generation can not be stored (e.g. run of the river hydro generation) and the fuel must be used at the time it is available. Alternatively, the generator may prefer that the generating unit stays connected throughout the day as costs of starting and stopping the generating unit are high.

Under the current dispatch rules in the EGRs, generators wishing to offer zero priced generation into the market must first bid into a must-run dispatch auction held daily by the Clearing Manager. Where a generator's bid is successful, the generator is authorised to offer a quantity of electricity at zero price for the relevant trading period. Any generation not cleared in the must-run dispatch auction must offer its output at $0.01/MWh. Generation successfully bid into the must-run dispatch auction will be dispatched (at zero price) ahead of the unsuccessful generation which will be dispatched at a price of $0.01/MWh.

Wind generation is a form of "must run" generation in that generation only occurs when the wind is blowing. Wind generation is treated as a zero priced generator in the dispatch process and is effectively a must run generator even though it is not bid into the must-run dispatch auction. This arrangement was a temporary measure implemented to allow Te Äpiti to be incorporated into the dispatch process until more permanent rules could be developed.

At certain times (e.g. low load conditions) the amount of zero priced generation offered in one island can exceed the island demand. The excess generation is not dispatched. The result is that potential electricity generation is lost (e.g. water is spilled) or thermal plant is dispatched off with high costs. Wind generation has two effects on the amount of zero priced generation.

First, wind generation is effectively treated as being must-run generation but is not bid into the must-run dispatch auction. This increases the likelihood of too much zero priced generation being offered as the current design of the must-run auction process takes no account of the zero priced wind generation.

Second, increasing amounts of wind generation connected to the power system increases the pool of generation that is offered or that generators may wish to offer at zero price. An excess of zero priced generation at certain times (e.g. low system loading) requires that some of this generation is not dispatched.

The overall effect of wind generation on must run generation is that the likelihood of some other forms of must run generation not being dispatched is increased (with the result that water is spilled by must run hydro or high starting and stopping costs are incurred by thermal plant). One option for mitigating these effects is to change the process by which must run generation is dispatched. The efficient and equitable inclusion of wind generation in the ‘must run’ generation dispatch process will help ensure that:

- any necessary “spilling” of fuel resource at times when must run generation is in excess of total system demand is done in a manner that best meets the government policy objectives for the Electricity sector,
- other types of must run generation from renewable sources are treated on the same basis as wind generation.

1.9 Options for mitigating the impacts

The observed impacts to the power system of the combined Manawatu wind generation are manageable under the current Electricity Governance Rules (EGRs). The connection of further wind generation (either in the Manawatu region or elsewhere) will increase variability in the power system. This may require changes to the way in which the operation of the power system and electricity market is managed. The effects of variability in the output of wind generation could be mitigated by a number of means.

1.9.1 Ramp rate controls

Ramp rate controls on wind turbines have been suggested as a means to reduce the impact of sudden changes in wind generation output and avoid the need for wider frequency keeping bands and increased frequency keeping costs. The ramp rate restriction has been analysed to determine the amount of time per event that generation would need to be restricted, and the total energy lost due to the restriction. The EGRs currently place no specific obligations for intermittent generation to have ramp rate control.

1.9.2 Improvements in Forecasting Accuracy

Inaccurate forecasts affect participants in the electricity market and the ability of the System Operator to meet the Principal Performance Obligations set out in Part C of the EGRs. Inaccuracy in forecasting affects participants by increasing uncertainty in trading outcomes. The security impact of greater inaccuracy in the schedule is the increased risk of transmission-constrained dispatch ‘surprises’ in real time. It is understood that the MetService, in conjunction with wind farm owners, is developing methods to improve the wind farm forecasts.

The centralised forecasting of wind generation output may be more accurate than forecasts provided by individual wind generators. This is an area that will be investigated in the Electricity Commission’s Wind Generation Investigation Project or that could be implemented by wind generators collectively as an initiative prior to the completion of the Wind Generation Investigation Project.

1.9.3 More frequent re-dispatch of generation

More frequent re-dispatch of generation will help mitigate the impact of sudden large changes in wind generation output. In the short term, automation of the dispatch process to produce dispatch instructions every five minutes and at any time when the wind generation output has changed materially away from the dispatched amount can be investigated. Such automation can help mitigate the effect of sudden large changes in wind generation output and also has benefits for the frequency keeper and for other generating plant as generation is re-dispatched more quickly to meet the changed power system conditions relieving the need for the frequency keeper and other generating plant to compensate for the sudden change in wind generation output.

The more frequent dispatch of generation using current processes is but an interim solution. A permanent solution may be required within a relatively short time frame. A high priority needs to be placed on investigating and implementing a permanent solution (such as Automatic Generation Control) as soon as possible. A high priority needs to be placed on putting in place the framework whereby a permanent solution (e.g. some form of AGC solution) can be agreed and implemented.

1.9.4 Changes to Frequency Keeping Management

The highest rates of change observed in the output of Manawatu wind generation are greater than the current minimum requirements for frequency keeping stations (i.e. 10 MW per minute). While some frequency keepers can provide a more rapid rate of change, frequency keepers are contracted to provide only the minimum rate of change. In addition, the magnitude of some changes (around 100 MW) exceeds the contracted and dispatched MW frequency keeping band (50 MW).

Options immediately available to the System Operator include increasing the minimum requirements for frequency keeping service providers and increasing the amount of frequency keeping procured. This is likely to increase the costs of the frequency keeping service. Another option is a requirement for ramp rate controls on wind turbines (which has been discussed previously). The implementation of Automatic Generation Control is another option.

1.9.5 Revision of transmission constraints

Changes in power flows across the grid following sudden large changes in Manawatu wind generation output may require revision of power system capability limits. It may also be necessary to revise operational policies to ensure that transmission circuits do not exceed stated capability if Manawatu wind generation output was to rapidly increase during a contingent event.

A variety of measures can be used to manage the risk of exceeding power system capability limits when there are changes in wind generation. This includes operators of wind generation arranging with Transpower for automatic schemes to monitor transmission capacity and wind generation output and modify the output of their wind generation. In the absence of any other controls applied collectively by asset owners, constraints to ensure that assets within the power system are kept within their stated capability will need to be applied in power system operation. Constraints can be used to:

- Dispatch generation so that the circuits in question will not exceed stated capability for a sudden increase in Manawatu wind generation output or constrain off Manawatu wind generation at the times when there is a risk of these circuits exceeding stated capability.
- Restrict the rate at which wind generating units change output.

1.9.6 Changes to dispatch of must run generation

Wind generation is effectively treated as zero priced generation in the scheduling and dispatch process. Wind generation is currently not bid into nor accounted for in the current must-run dispatch process. This increases the likelihood that some must-run generation is not dispatched with consequent spilling of water or the incurring of high starting and stopping costs). Interim rule changes to either the must run auction process or the way in which wind generation is treated by SPD will be considered. This is an area that will also be investigated in the Electricity Commission's Wind Generation Investigation Project. See also earlier comments in section 1.8.3 on this matter.

1.10 Increased installed wind generation capacity in the Manawatu region and the North Island

1.10.1 Manawatu Region

The first part of the analysis in this report illustrates the current effect of wind generation in the Manawatu region on the power supply of New Zealand. Consents for further wind generation in the Manawatu region have been sought and some have been gained. It is likely, that the new wind generation in the Manawatu region may show a similar correlation to the strong correlation observed between the Tararua and Te Äpiti wind farms.

There is currently over 150 MW of installed wind generation capacity in the Manawatu region (Te Äpiti and the Tararua North and South wind farms). Resource consents have been gained for the Tararua III wind farm (93 MW) and the Te Rere Hau wind farm (48.5 MW). As a result, it is likely that there will be an additional 140 MW of installed wind generation capacity in the Manawatu region in the future. There is likely to be 300 MW of installed wind generation capacity in close proximity to the Manawatu gorge.

If this is the case, the size (MW change in five minutes) of the Type I events will be expected to increase proportionally as more wind generation capacity is added. Hence events that are 66% of the current capacity of the wind farms will increase from 100MW to 200MW if the output of the wind farms were to increase from 150MW to 300MW. The analysis has shown that this type of event would be expected to occur around 10 times each year.

The size of the Type II events would also be expected to increase with the addition of further wind generation capacity in the Manawatu region. If the new wind generation was strongly correlated with the existing wind generation then this type of variability would be expected to increase proportionally. Hence the 12 forecast Type II events each year of a change of around 33% of installed wind capacity in five minutes can be expected to increase from 50 MW in size to 100 MW if the output of wind generation in this area were to double. If the new wind generation is not strongly correlated then an increase in this type of variability would still be expected, but to a lesser degree.

1.10.2 North Island

There is currently just less than 170 MW of installed wind generation capacity in the entire North Island. Resource consents for another 210 MW of wind generation in the North Island have been granted. Resource consents for an additional 560 MW of wind generation have been applied for. Responses from the Request For Information on wind generation (put out in July 2005) indicate that a further 370 MW of wind generation beyond that already consented or in the consent process is being considered.

It is likely that the amount of installed wind generation in the North Island will at least double within the next two years as the consented wind generation is commissioned. The amount of wind generation capacity installed in the North Island in three to five years time could potentially be in the range of 850 MW to 1300 MW.

The correlation between changes in wind generation output in different regions has not yet been determined. However, it seems likely for installed North Island wind generation capacity in the range 850 MW to 1300 MW that:

- Sudden large changes in North Island wind generation output of between 200 MW to 400 MW over five minutes might be expected to occur on a monthly basis. This is based on characteristics of the Type II (non weather condition related) events observed at Te Äpiti and is consistent with information provided by a wind generator for wind speeds at sites in a number of regions across New Zealand. Changes of this size will have significant implications for the management of frequency and transmission circuit loadings and potentially voltage management and other power quality issues.

- The inaccuracy in the total of the forecasts for wind generation output in the North Island could be greater than 250 MW for 10% of the time. This assumes that 10% of forecasts will have an error of greater than 33% of installed capacity (similar to Te Äpiti forecast accuracy) but that some of the errors will cancel out.

In formulating interim rule changes, the Tactical Project will consider what rule changes will be required to manage the effects of the committed and existing wind generation along with that likely to be committed and operating within two years. The scope of the WGIP is to consider power system operation and market changes required to manage wind generation capacity that will be installed over the next 10 years.

1.11 Conclusions

Analysis of the variability of Manawatu wind generation indicates:

- Sudden large changes in wind generation output (of 50 MW or greater in five minutes) are likely to occur around 20 times[3] per year for the current amount of installed wind generation capacity in the Manawatu region.
- Large changes in wind generation output over a short period may cause power system frequency excursions.
- The observed rates of change in Manawatu wind generation are at times greater than the minimum ramp rates requirements for frequency keeping service providers.
- The size of the changes in Manawatu wind generation is at times greater than the typical frequency keeping MW band dispatched.
- An improvement in the accuracy of Te Äpiti's two hour forecasts has been observed since January 2005. There have been no improvements in the six and 12 hour forecasts.

In addition to the observed effect on power system frequency, sudden changes in Manawatu wind generation cause changes in power flow across the transmission grid which may cause assets to exceed their stated capability. Inaccuracy in provided forecasts of wind generation reduces the System Operator's ability to manage the power system securely and increases uncertainty for other generators in the planned dispatch of their plant.

It must be noted that some of the observed impacts (e.g. weather condition related sudden large changes and correlation between wind farm outputs) may be unique to Manawatu wind generation and may not occur with wind generation installations in other parts of New Zealand.

[3] Based on an extrapolation of the limited amount of data analysed in this report.

Overall, the current effects of Manawatu wind generation variability on the operation of the power system and the electricity market are manageable using the policies and means available to the System Operator set out in the policy statement in Part C of the EGRs. However, any increase in the amount of Manawatu generation means that the System Operator will have to review the policies and means in the policy statement along with the dispatch rules in Part G.

The System Operator will be identifying and proposing rule changes, where required, as part of the next stage of the Tactical Project so that the impacts of additional wind generation can be managed to ensure the integrity of the power system ahead of any further changes from the WGIP. The process of identifying and proposing any required rule changes is planned to be completed in October 2005 and submitted to the Electricity Commission for processing through its rule change processes.

2 Introduction

2.1 The context of the report

The integration of large scale wind generation into power systems is a challenge facing system operators, grid owners and regulators worldwide. Wind and other forms of intermittent generation have quite different characteristics to the forms of generation around which power system operation and electricity markets have been designed. In addition, the challenge of integrating large scale wind generation into New Zealand power system is compounded by three factors:

- The New Zealand power system has no interconnections to other power systems and can not draw upon other power systems' resources.
- The long and stringy nature of the New Zealand power system (generation and load are connected by long transmission lines).
- The nature of the wind resource in New Zealand (gusty and concentrated in certain areas rather than even flows and diversely spread across the country).

The Electricity Commission has instigated two initiatives to meet the challenge of integrating large scale wind generation. These are:

1. *The Wind Generation Investigation Project (WGIP).*
   The objective of the WGIP is to
   - Identify and quantify the technical and electricity market impacts of wind generation upon the New Zealand power system over the next ten years;
   - Recommend (if and as required) amendments to the Electricity Governance Rules and other relevant arrangements / processes to ensure power system security and market outcomes are achieved that are consistent with the Government Policy Statement on Electricity Governance (GPS) and Commission's Principal Objectives and Outcomes; and
   - Recommend an implementation plan for proposed changes, to the extent that this is required.

   This is a long term project and as a result the rule changes identified by the WGIP are expected to take two years to implement.

2. *The Tactical Project.*
   The Tactical Project has two objectives. The first objective is an assessment of the impact of the Manawatu wind generation on scheduling and dispatch. The second objective is to identify and recommend any necessary rule changes required to accommodate the integration of wind generation into the New Zealand power system for the interim period before the WGIP is completed.

The process for the first part of the Tactical Project (for which this report is the culmination) has been to:

- assess the impact of Manawatu Wind Generation on scheduling and dispatch for November and December 2004 and publish a report[4]. This report was published in March 2005,
- continue the analysis for the period January to April 2005,
- consult informally with Meridian Energy Limited and Trustpower on the outcome of analysis,
- publish a revised report in September 2005.

The process for the second part (to identify any necessary rule changes for the interim period) is to:

- request information (via the Electricity Commission consultation framework) to identify possible rule changes. This consultation was carried out in July-August 2005,
- identify the necessary rule changes and propose recommendations to the Electricity Commission. This is expected to be completed in October 2005.

This report focuses on the impact of Manawatu wind generation between November 2004 and April 2005. It does not investigate the effect of other generation and load behaviours on the operation of the power system and electricity market. These behaviours are generally understood and accounted for in the operation of the power system and electricity market. The impact of the variability of the existing amount wind generation farms is significant and as yet not well understood. The impact of the variability of the amount of future wind generation proposed to be connected to the power system will require changes to power system operation and the electricity market.

The two Manawatu wind generation impact reports and submissions to a Request For Information on wind generation from the Electricity Commission (submissions received on 22 July 2005) will also be used as input into the interim rule change process.

2.2 Background

There are two existing wind farm sites in the Manawatu region – Tararua wind farm owned by Trustpower Limited and Te Äpiti wind farm owned by Meridian Energy Limited. The Tararua wind farm is embedded behind the Linton and Bunnythorpe grid exit points and has been in operation since 1999. The Te Äpiti

[4] This report was published on the Electricity Commission's web site in March 2004. The report is titled "Impact of Manawatu wind generation on the scheduling and dispatch processes, 28 February 2005".

wind farm was connected to the grid near Woodville in late 2004. The combined installed capacity of the two wind farms is over 150 MW.

Wind and other forms of intermittent generation are quite different to the forms of generation around which power systems have evolved. Conventional hydro and thermal generation plant has the ability to control its output by adjusting its fuel input. Such generating units can maintain a set level of power output by adjusting the fuel input. The power output of conventional hydro and thermal generation is largely predictable and constant.

Wind generation can not control its power output in such a way – it is dependent on the wind that is blowing at the time. This has some implications for power system and electricity market operation which has been designed around predictable and constant generation.

When the level of wind generation penetration is small, the effects of its unpredictability and variability make little impact on the power system. However, with increasing amounts of wind generation connected to the power system, there comes a point where the impacts of unpredictability and variability of wind generation become significant for the operation of the power system.

This report analyses the impact that the unpredictability and variability of the Manawatu wind generation output has had upon the operation of the New Zealand power system and upon scheduling and dispatch during the period between November 2004 and April 2005.

At present, the installed capacity of wind generation on the New Zealand power system is small compared to the installed capacity of other types of generation and the effects of its unpredictability and variability have had limited impact on the power system. A significant amount of wind generation is likely to be connected to the New Zealand power system within the next two years. It is likely that a considerable amount will be added in the Manawatu region. The effects of the variability and unpredictability of this additional wind generation can not be predicted with certainty but are likely to be greater than the effects observed to date.

2.3 Structure of the analysis

This report presents analysis of the effect of wind generation in the Manawatu region on the power system and the electricity market in New Zealand. Section 3 discusses the effects of wind power variability in Manawatu region that affects the operation of the New Zealand power system and electricity market. The impacts on power system operation are then analysed in Section 4 with reference to frequency keeping and transmission constraints. Section 5 discusses the impacts on the electricity market. Assessment on options for mitigating the options is presented in Section 6. Section 7 covers a discussion on the effects of increased installed wind generation capacity in the Manawatu region and the North Island. Finally, Section 8 summarises recommendations and conclusions of the report.

The data used in the analysis carried out for this report has come from a variety of sources. Appendix 1 contains a detailed description of this data.

3 Manawatu Wind Generation Output Variability

The amount of generation output from the two wind farms in the Manawatu region has been observed to vary significantly over a day. This variability makes the forecasting of future amounts of wind generation difficult. There have also been a number of large changes in the amount of wind generation output within short time periods. Managing these large changes in output in real time can pose operational difficulties.

Figure 1 shows the number of observed changes in combined Manawatu wind generation output above 25 MW over five minutes for the period December 2004 to March 2005, plus events greater than 50 MW over five minutes for November 2004.

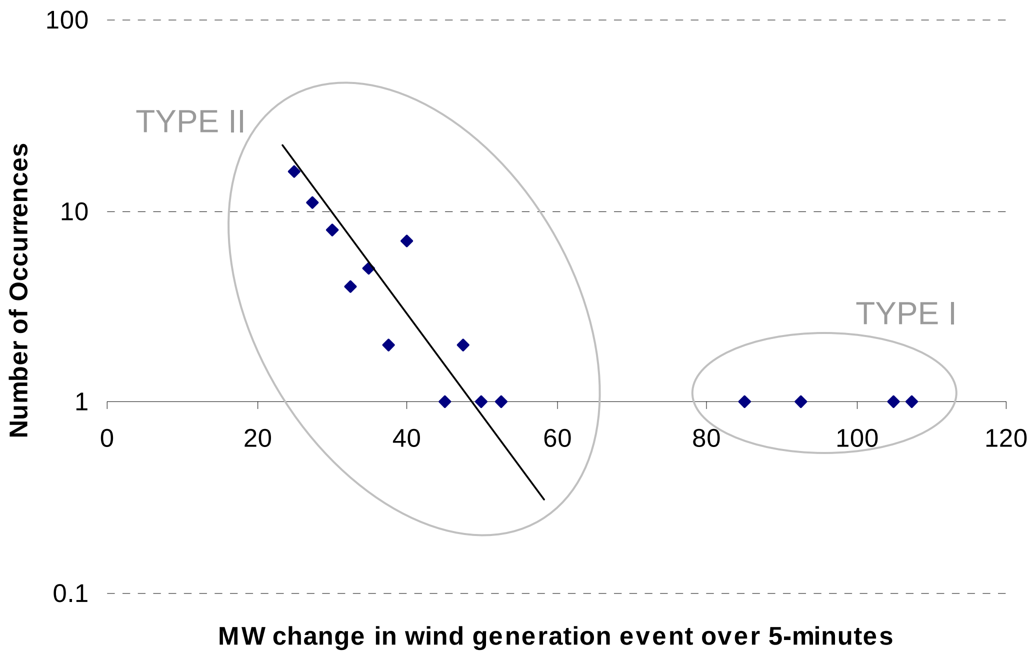

Figure 1 – Number of observed changes in Manawatu wind generation output as a function of size (MW)

Figure 1 suggests that there are two apparent types of sudden change in the amount of generation output. The first type of sudden change (Type I) seems to occur during certain specific weather conditions, which are discussed in detail in Section 3.1.2. The average size of these events is around 100 MW which is roughly equivalent to 66% of the currently installed wind generation capacity in the Manawatu region. Based on observations to date, it is expected that around 10 events of this type will occur each year. It is possible that this type of change is a result of weather conditions unique to the location of wind farms in the Manawatu region.

The second type of sudden change (Type II) is smaller in size and seems to show a correlation between the number of occurrences of an event and size of the sudden change in generation. It is possible that these events may reflect the natural variability of wind speeds (and hence wind generation output) in the region. Based on observations to date, it is expected that around 12 events of a change of 50 MW (33% of currently installed wind capacity) in five minutes will occur each year.

It should be noted that six months is not long enough to observe all events that might occur. Further observation is required to confirm the probability of the occurrence of sudden large events in Manawatu wind generation output.

3.1 Sudden large changes in Manawatu wind generation output

A number of sudden large changes in the combined Manawatu wind generation output were observed during the period from November 2004 to April 2005. Analysis of the impact upon power system operation of some of these events (i.e. those where an increase or decrease of greater than 50 MW in a five minute period occurred) has been carried out.

There are two reasons why this size of event has been examined:

- A 50 MW change in five minutes equates to the minimum required frequency keeper[5] response rate of 10 MW per minute, and
- ±50 MW is the size of the typically dispatched frequency keeping band.

Six such events (a change of greater than 50 MW over five minutes) have been identified. These are listed in Table 2.

Event Number	**Date and Time**	**Approximate output change, and interval**
1	15 Nov 2004, 01:00 to 02:00	140MW in 13 min increase (105MW in 5 minutes)
2	23 Nov 2004, 23:50 to 24:00	110MW in11 min increase (85MW in 5 minutes)
3	30 Dec 2004, 16.45 to 17.00	130MW in 12 min increase (93MW in 5 minutes)
4	14 Feb 2005, 11:30 to 12:00	70MW in 12 min increase (53MW in 5 minutes)
5	14 Feb 2005, 14:30 to 14:45	120MW in 10 min increase (109MW in 5 minutes)
6	25 Mar 2005, 10:50 to 11:05	70MW in 8 min increase (50MW in 5 minutes)

Table 2 - List of events during Nov 2004 - Apr 2005 where there was a change of greater than 50 MW over five minutes.

[5] See Section 4.1.

The most extreme five minute change in wind farm output was recorded for event 5 on 14 February 2005. Figure 2 shows the Tararua and Te Äpiti wind farm generation during the event. Plots for the other 5 events in Table 2 are given in Appendix 2.

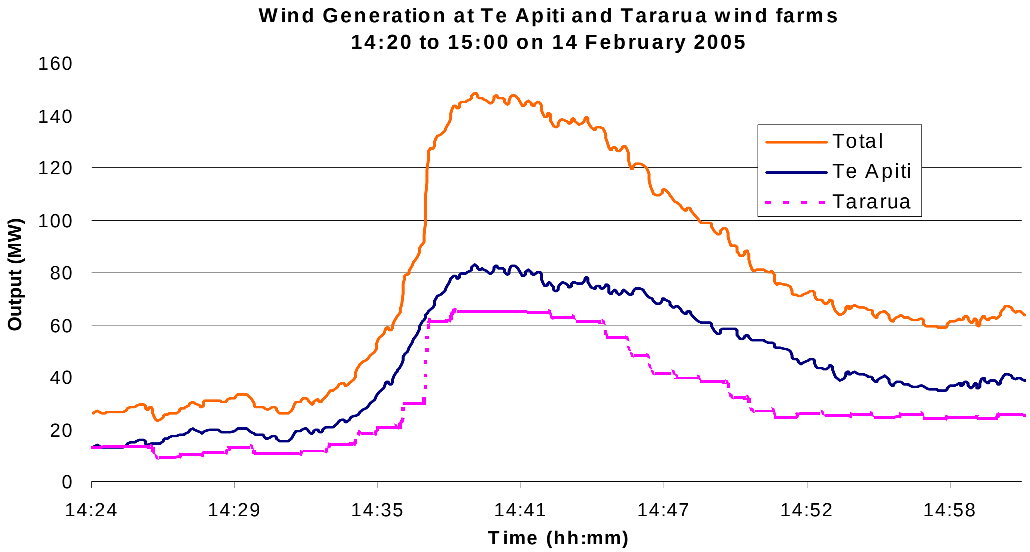

Figure 2- Rapid changes in Manawatu wind generation output

In a period of about five minutes the combined wind generation rose from 40 MW to a peak of about 150 MW. Generation output then fell back to 60 MW at a more gradual rate. Such rapid changes in wind generation output affect power system frequency in the North Island (see Section 4.1).

3.1.1 Correlation during events

Figure 2 also shows a strong correlation between the outputs of the two wind farms. The correlation between the Tararua and Te Äpiti wind farm generation output was analysed for the events in Table 2. The analysis from four of the events is included in Appendix 2. For these four events the wind generation changed by a minimum of 85 MW and a maximum of 109 MW in a five minute period.

The current high level of correlation observed between the output at Te Äpiti and Tararua wind farms during sudden changes would suggest the possibility of similar correlation for further wind generation installed in the Manawatu region. If this is the case then when a event similar to those in Table 2 occurs the size of the change in wind generation output would be expected to be even larger and the impact on the power system greater.

3.1.2 Meteorological circumstances of the large events

The Meteorological Services of New Zealand (MetService) has investigated the meteorological circumstances of the events where the change in the combined

Tararua and Te Äpiti wind generation was greater than 50 MW in five minutes for the period 1 November 2004 to 30 April 2005. This investigation has drawn some conclusions about the predictability and frequency of occurrence of such events.

The MetService findings show that the meteorological situations of all these events are essentially the same - a large, slow moving depression west of the South Island, and a frontal system moving eastwards across the southern part of the North Island. A change in the direction of the wind flow across the axis of the main North Island mountain ranges is an important contributing factor (e.g. a situation where the wind is first blowing from the east or northeast, and then blows from northwest or the west).

During the shift in wind direction from east through north to west there is a time when the wind direction is aligned with the main ranges and the wind speed is temporarily reduced. Later when the direction becomes more or less perpendicular with the axis of the ranges, there is a fairly sharp increase in wind speed. It is not clear if this is due to the particular stability structure of the frontal zone in a cold front or a dynamical effect of the interaction of the changing wind direction and the topography (shape of the terrain).

Summary details of the MetService findings are included in Appendix 3.

4 Impacts on power system operation

Sections 4.1 – 4.3 analyse the effect of the events in Table 2 on the operation of the power system. The analysis covers the effect on frequency keeping and transmission constraints.

4.1 Frequency keeping

4.1.1 Introduction

A mismatch between generation and load on the power system will cause the power system frequency to rise or fall. These mismatches occur constantly as demand on the power system is constantly varying. This results in changes in power system frequency which must be managed.

The System Operator manages power system frequency (nominally 50 Hz) by procuring the frequency keeping ancillary service. This ancillary service is provided by a generating station which is contracted and dispatched for that purpose. The frequency keeping station (the “frequency keeper”) in each island changes its output to match changes in other generation and load in order to maintain power system frequency between 49.8 Hz and 50.2 Hz (the normal band). There is usually one frequency keeper in each island. Sudden changes in the level of Manawatu wind generation output are largely compensated by the frequency keeper until re dispatch of other generation occurs.

Rapid generation changes can impact on the frequency keeper’s ability to provide frequency keeping. Problems caused by rapid changes in generation include:

- The rate of increase or decrease in wind generation output can exceed the capability of the frequency keeper to change its output to maintain island frequency within the normal frequency limits.
- A large increase or decrease in generation can be greater than the dispatched frequency keeping band, and may cause the frequency keeper to exceed its dispatched quantities of frequency keeping.

4.1.2 Analysis of Large wind events

During each of the six events in Table 2, the impact of the sudden change in wind generation output on the frequency keeper was analysed. It is evident that the frequency keeper compensates for this rapid change in wind generation output in each of these events before generation is re-dispatched.

Figure 3 shows the effect of a sudden large event occurring on 15 November 2004 starting at around 01.00 hours on the North Island frequency keeper and on North Island frequency. The dispatched frequency keeping (band) limits are shown to illustrate when the frequency keeper has had to go outside the band in an effort to maintain the island frequency.

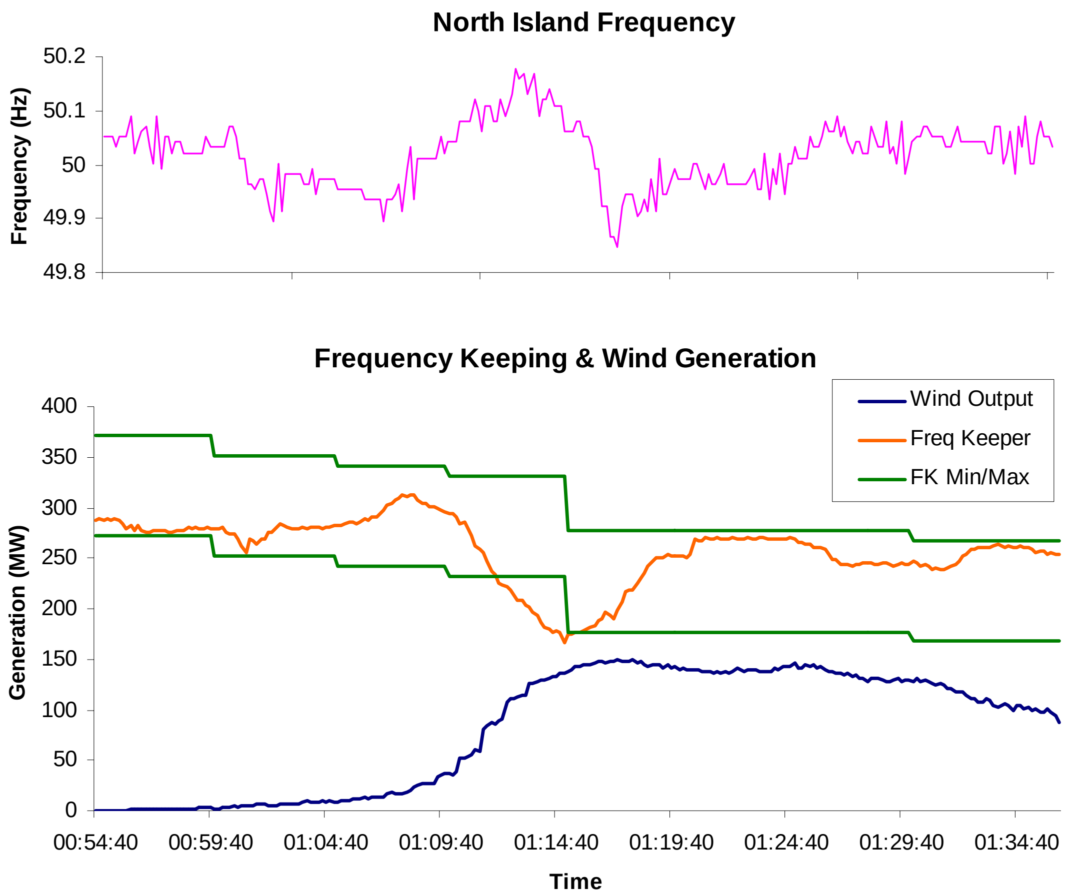

Figure 3 - North Island frequency, frequency keeping (and frequency bands) in response to event 1 (15 November 2004)

Figure 3 shows a rapid increase in Manawatu wind generation output from around 01:00. During this event the total wind generation increased by a maximum of 105 MW over 5 minutes and 150 MW in 20 minutes. From Figure 3, it is evident that nearly all of this increase in generation is offset by the frequency keeper which reduced output in response to the increase in the North Island frequency. During this time the frequency keeper moves outside the frequency band and the North Island frequency moves 0.3 Hz to a peak near 50.2 Hz, the upper limit for normal frequency band.

Similar analysis for the other events in Table 2 has been carried out (see Appendix 5 for details) and the results are summarised in Table 3.

Event	Date	Trading periods	Five Minute MW Change	Frequency or frequency keeping station outside band.	Comments
1	15/11/04	3 & 4	105	Yes	
2	23/11/04	48	85	Yes	
3	30/12/04	34	93	No	
4	14/02/05	24	53	Yes	Frequency keeper was already out side band
5	14/02/05	30	109	Yes	Frequency keeper was already out side band
6	25/03/05	22	50	Yes	Frequency keeper was changed during the steep increase in wind generation

Table 3 - Observed large changes in wind farm generation events greater than 50 MW (November 2004 to April 2005).

For two of the six events in Table 2 (15 November 2004 and 25 March 2005) the sudden change in wind generation output resulted in the frequency keeper going outside its dispatched MW frequency keeping band. These events have an impact on North Island frequency, and on one occasion (23 November 2004) the North Island frequency moved outside the normal frequency band. Two of the events (15 November 2004 and 14 February 2005) had rates of change of output that were twice the contracted frequency keeper response rate (of 10 MW per minute), and were twice the size of the dispatched frequency keeping response band (±50 MW).

It should be noted that during five of these events frequency keeping was being provided by a hydro generation station. This type of generation plant has a high response rate in terms of frequency keeping. The high response rate of the frequency keeper combined with the response of other generating plant connected at the time meant that the impact of wind generation output increase was able to be managed with minimal impact on the power system. Thermal generation units used for frequency keeping in the North Island do not respond as quickly as hydro plant nor (normally) have adequate capacity to cover such a rapid change in generation.

One option to mitigate the impact of sudden large changes in wind generation output is the automation of the issuing of dispatch instructions. This is currently a manual process. The automated issuing of dispatch instructions every five minutes and also when wind generation output has materially varied from the dispatched amount will improve power system security and help manage sudden large changes in wind generation output.

4.2 Transmission Constraints

The System Operator dispatches generation every five minutes to achieve secure, optimal and economic power flow. The secure dispatch ensures that power system capability limits are not exceeded for an outage. The sudden increase in wind generation output in the Manawatu region combined with a corresponding reduction in generation output by the frequency keeper causes a change in power flow within the circuits that make up the transmission grid. This change in power flow has the potential to cause some transmission circuits to exceed their stated rating until the System Operator is able to dispatch other generators to compensate for the change. Power system capability limits may need to be put in place to avoid assets exceeding stated capability during a sudden change in wind generation output.

Two scenarios have been identified where the change in power flow, following a change in Manawatu wind generation output, has an effect on power system capability limits:

- High North transfer through the North Island.
  A sudden increase in Manawatu wind generation output can cause power system capability limits to be exceeded during high power transfer to the north of Bunnythorpe. The limitation is on the Tokaanu - Whakamaru circuits.
- HVDC South transfer.
  Power system capability limits can be exceeded during high power transfer to the south of Bunnythorpe during a sudden decrease in Manawatu wind generation output. The limitation is on the Brunswick - Stratford circuits and applies while summer ratings are in effect.

Further information on the effect of Manawatu wind generation on power system capability limits has been included in the July 2005 Amendment to the System Security Forecast (http://www.transpower.co.nz/?id=4464).

5 Impacts on the electricity market

5.1 Forecast Accuracy

5.1.1 Introduction

Wind generation (and other forms of intermittent generation) is not offered[6] into the electricity market in the same manner as other types of generation are offered. As part of the wind generation offer, a forecast of the amount of wind generation in a trading period is provided to the System Operator. The accuracy of the provided forecast is dependent on the wind generator's ability to predict the amount of wind generation in advance.

As part of the scheduling process, the System Operator schedules offered generation to meet forecast load. The forecasts provided by wind generators are used in the scheduling process. Inaccuracy in wind generation forecasts means that generation that is actually dispatched in a trading period can be quite different to the generation that was scheduled earlier. This has two impacts.

Impact on power system security

The System Operator uses the scheduling process to identify possible power system security issues (e.g. not enough generation offered in a particular trading period). Inaccurate wind generation forecasts can mean that generation dispatched in a trading period is quite different to the generation that was scheduled and for which power system security analysis was carried out. This increases the risk that power system security issues emerge during dispatch. This affects the System Operator's ability to manage the power system securely.

The current level of wind generation forecast accuracy is manageable within the current scheduling and dispatch processes (although the effects of forecast inaccuracy are being observed). As increasing amounts of wind generation capacity is installed, there will come a point where the inaccuracy in the wind generation (or other intermittent generation) is so large that power system security can not be safely managed using the current processes and software tools.

One option is to improve the accuracy of wind generation forecasts, perhaps through the introduction of centralised wind generation forecasts as has been implemented in other countries.

[6] It should be noted that the output of Te Apiti is the only wind generation currently offered into the electricity market.

Impact on market outcomes

Pre-dispatch Generation schedules produced in the scheduling process provide information to market participants who can then adjust their offers of generation and bids of load in response to the forecast prices in the schedules. This allows generators to optimise the efficiency of their generating units and to plan starting and stopping of their plant. Price forecasts are used by purchasers to adjust their bids, for example, reducing the amount of electricity they intend to consume during future trading periods where the price is high.

Inaccuracy in wind generation forecasts affects the accuracy of the generation schedules. Generators and purchasers who use the information in the pre-dispatch schedules to plan their offers and bids will find that the actual dispatch in some trading periods is quite different to the schedule around which they based their offers and bids. This difference will result in increased plant operating costs and opportunity costs (e.g. where generators did not offer their plant based on low forecast prices but where the final prices were high).

5.1.2 Te Äpiti Generation Forecast Accuracy

Meridian receives a MetService forecast for Te Äpiti at around 09:00 and 15:00 hours each day. For the period November 2004 to mid January 2005 Meridian used this information to create a day-ahead generation offer from midnight that day to midnight the next day. The Te Äpiti generation offer for the next two hours was generated by a persistence forecast using the 10 minute average from the current trading period. The persistent forecast was updated twice during each trading period. Since mid January 2005, this process has been modified; the MetService forecasts are now used to generate a day-ahead forecast covering the period three hours ahead to midnight the next night. The persistence forecast has been extended and used as the Te Äpiti offer for the next three hours.

The pre-dispatch schedules provide important information for market participants and are used by the System Operator to assess power system security. Security assessments are carried out four times a day. Participants are notified of identified security issues enabling them to respond to such warnings and revise their bids or offers. The longer range forecasts (such as twelve hours out) are important for standby generation availability given it can take thermal units over eight hours to commit. The shorter range forecasts (such as six hours out) are important as participants will revise their offers and bids to in response to notified security issues.

The Te Äpiti generation forecast offers for the trading periods 2, 6 and 12 hours ahead have been analysed for the months November 2004 through to March 2005. The details are included in Appendix 6. Figure 4 shows the cumulative distribution of the Te Äpiti two hour forecast generation error for months November 2004 to April 2005.

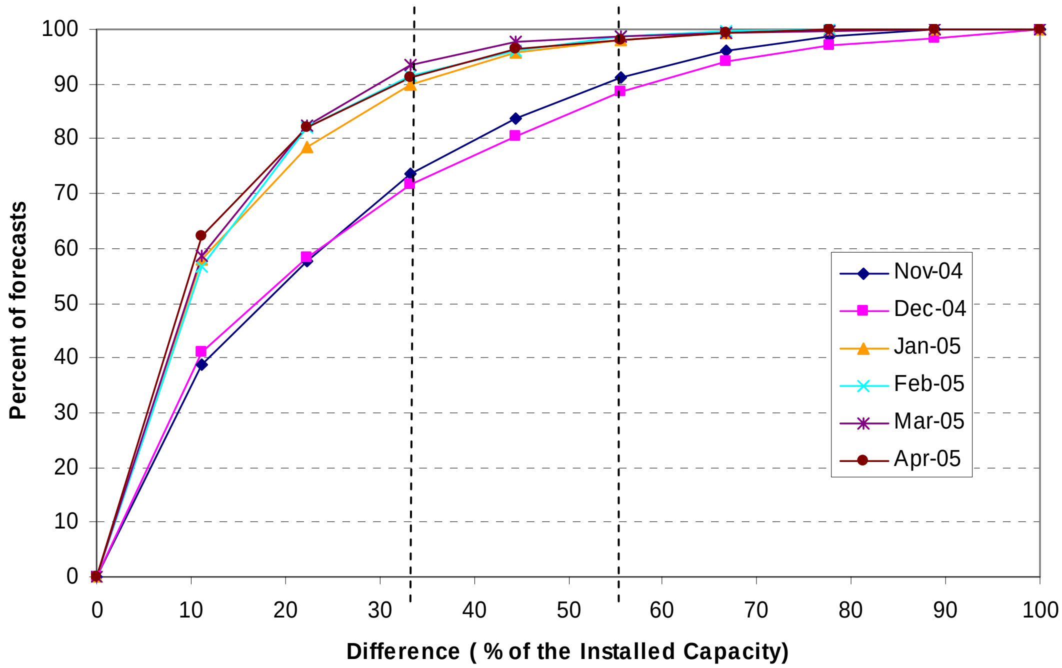

Figure 4- Cumulative distribution of the Te Äpiti two hour forecast generation error (for months November 2004 to April 2005).

Figure 4 shows an obvious improvement in the two hour ahead forecast as a result of the extension of the persistent forecasts in January 2005. In November and December 2004 about 10% of the 2 hour forecasts had an error of greater than 55 % of the installed capacity. From January 2005 the number of errors of this size has reduced to 2% or less of the forecasts. While the two hour forecasts of Te Äpiti wind generation output have improved, the six and twelve hour forecast errors for Te Äpiti wind generation have not improved since the analysis carried out in November and December 2004.

5.1.3 Tararua Generation Forecast Accuracy

The Tararua wind farm forecasts are submitted to the System Operator every six hours. Analysis was carried out on the two hour forecasts for November 2004. Consequently only about 100 forecasts were analysed for the month, but the results indicate a higher degree of forecast error than observed in the Te Äpiti forecasts (see Figure 5 and Figure 6).

Around 50% of the Tararua forecasts had an error of greater than 16% of the installed wind farm capacity. Around 18% of the forecasts had an error of greater than 50% of the installed wind farm capacity.

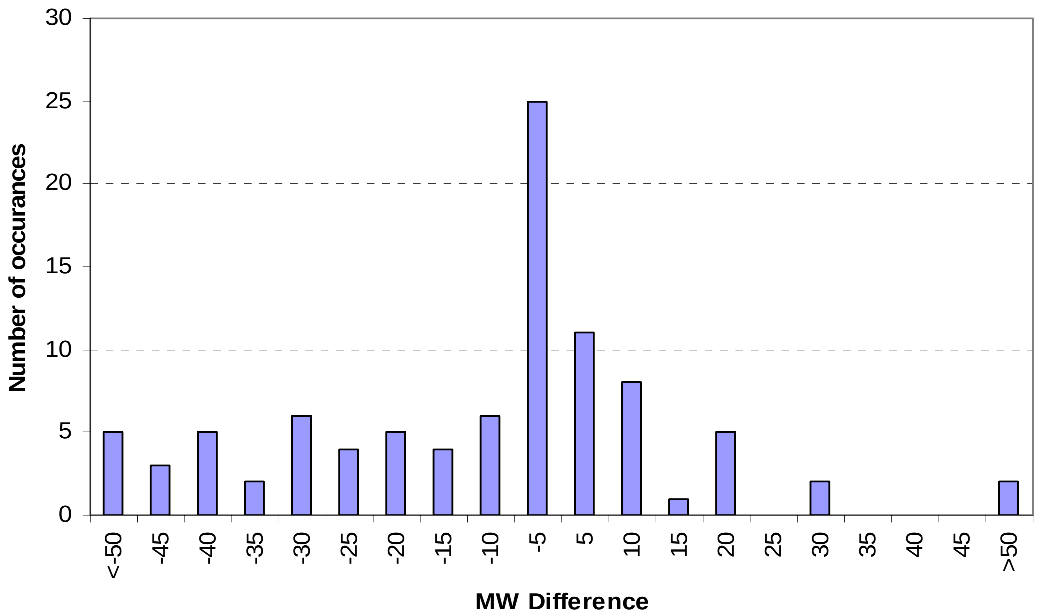

Figure 5 - Frequency distribution of the Tararua two-hour forecast error for November 2004.

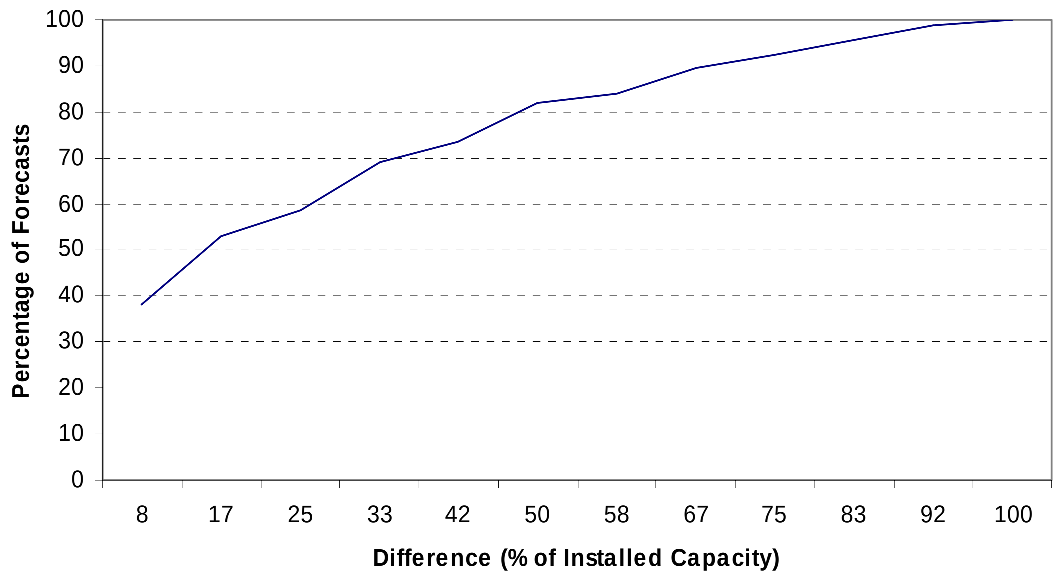

Figure 6 - Cumulative distribution of the error of the Tararua two-hour forecast for November 2004.

5.1.4 Must Run Generation

The output of some generating units is offered into the electricity market at zero price. The reasons for doing this can be because the fuel source for the generation can not be stored (e.g. run of the river hydro generation) and the fuel must be used at the time it is available or because the generation prefers to stay connected throughout the day as costs of starting and stopping the generation are high.

Under the current dispatch rules in the EGRs, generators wishing to offer zero priced generation into the market must first bid into a must-run dispatch auction held daily by the Clearing Manager. Where a generator's bid is successful, the generator is authorised to offer a quantity of electricity at zero price for the relevant trading period. Any generation not cleared in the must-run dispatch auction must offer its output at $0.01/MWh. Generation successfully bid into the must-run dispatch auction will be dispatched (at zero price) ahead of the unsuccessful generation which will be dispatched at a price of $0.01/MWh.

Wind generation is a form of "must run" generation in that generation only occurs when the wind is blowing. Wind generation is treated as a zero priced generator in the dispatch process and is effectively a must run generator even though it is not bid into the must-run dispatch auction. This arrangement was a temporary measure implemented to allow Te Äpiti to be incorporated into the dispatch process until more permanent rules could be developed.

At certain times (e.g. low load conditions) the amount of zero priced generation offered in one island can exceed the island demand. The excess generation is not dispatched. The result is that potential electricity generation is lost (e.g. water is spilled) or thermal plant is dispatched off with high costs. Wind generation has two effects on the amount of zero priced generation.

First, wind generation is effectively treated as being must-run generation but is not bid into the must-run dispatch auction. This increases the likelihood of too much zero priced generation being offered as the current design of the must-run auction process takes no account of the zero priced wind generation.

Second, increasing amounts of wind generation connected to the power system increases the pool of generation that is offered or that generators may wish to offer at zero price. An excess of zero priced generation at certain times (e.g. low system loading) requires that some of this generation is not dispatched.

The overall effect of wind generation on must run generation is that the likelihood of some must run generation not being dispatched is increased (with the result that water or wind is spilled or high starting and stopping costs are incurred). One option for mitigating these effects is to change the process by which must run generation is dispatched.

5.2 Generation Scheduling and Nodal Prices

The System Operator prepares two generation schedules for the market, the Pre-Dispatch and the Schedule of Dispatch Prices & Quantities[7]. Generators offer generation into the schedules. A hydro or thermal generator will manage their stations so that any offered and dispatched generation is met. In contrast, the wind generation forecasts used in the preparation schedules may be quite different from the actual wind generation output in the trading period.

Should the wind farm generation output vary from forecast; the difference will be offset over the trading period by other generators. If the wind farm generation output is greater than its forecast by 100 MW, other generators will be dispatched for 100 MW lower than what was forecast for them. One impact of this is that some generators will be uncertain in advance of their dispatched quantity for a trading period and hence may not be able to run their plant at a desired efficiency.

Inaccuracies in forecast wind generation output may result in differences between forecast final prices and the prices that are finally cleared. Uncertainty in forecast prices will reduce the ability of generation and load to efficiently respond to the forecast prices.

7 Load is determined for each of the trading periods into the future by either demand side bids (for the Pre-Dispatch Schedule), or forecast load from the Load Forecast application (for the Schedule of Dispatched Prices and Quantities).

5.2.1 *Effect of wind forecast on final prices*

The scheduling process creates generation schedules that clear the offered generation based on the least solution cost accounting for losses to meet the forecast load. At dispatch, the lowest priced generation is dispatched to meet the system load and losses at the time. The last generation offer cleared (the marginal generator) and dispatched sets the price (with other generation prices being close to this price but nodal accounting for losses). Wind generation is zero priced and is always fully dispatched to their present output level.

Consider the example where wind generation is forecast to be 50 MW and that the offer of the marginal generator is $40 per MWh. If the amount of wind generation during the dispatch period is zero then 50 MW of other generation will be dispatched. The cost of this additional generation will be at least $40 per MWh and more if a new generation offer (at a higher price) is required to be dispatched. Likewise, if the amount of wind generation in the trading period is 100 MW then the marginal generator will be backed off and possibly not dispatched (and the price may be lower).

There are many factors that will cause the forecast prices in the generation schedules to differ from final prices. For example, generators and purchasers have the ability to revise their offers and bids at any time prior to two hours before dispatch.

An indication of how wind generation forecast inaccuracy might affect final prices can be determined by comparing the final prices for a particular trading period with what would have been the final prices if Te Apiti had generated its forecast amounts, and assuming that all other generation offers stayed the same.

Trading periods at the time of the four largest wind generation events observed between November 2004 and March 2005 were analysed. The analysis indicated that difference in final prices (between actual wind generation output in the period and the forecast amounts at 12 hours and six hours out) is between -$15 to $5 per MWh. The difference at two hours out is between -$3 and $5 per MWh. Note that there was no change in final price for some trading periods analysed. These differences affect the total cost of generation dispatched by up to around 75 thousand dollars for a single trading period.

6 Options for mitigation

The observed impacts to the power system of the combined Manawatu wind generation are manageable under the current EGRs. The connection of further wind generation (either in the Manawatu region or elsewhere) will increase the amount of variable generation, and hence uncertainty, in the power system. This may require changes to the way in which the operation of the power system and electricity market is managed. The effects of variability in the output of wind generation could be mitigated by a number of means.

6.1 Ramp rate controls

Ramp rate controls on wind turbines have been suggested as a means to reduce the impact of sudden changes in wind generation output. In situations where the rate of change in generation is large, capping of the rate of change means that the variability in the power system is not as great. This enables the frequency keeping station to better match the change and stabilise power system frequency. It is most common to use ramping constraints when generation is increasing. Therefore the analysis in this section focuses on ramp up events only.

The ramp rate restriction has been analysed to determine the amount of time per event that generation would need to be restricted, and the total energy lost due to the restriction. Figure 7 illustrates the influence of a 5, 10 and 20 MW ramp control on the combined Te Äpiti and Tararua wind farm generation for the event observed on the 23 November 2004. During this event the combined wind farm generation increased by about 110 MW over 11 minutes.

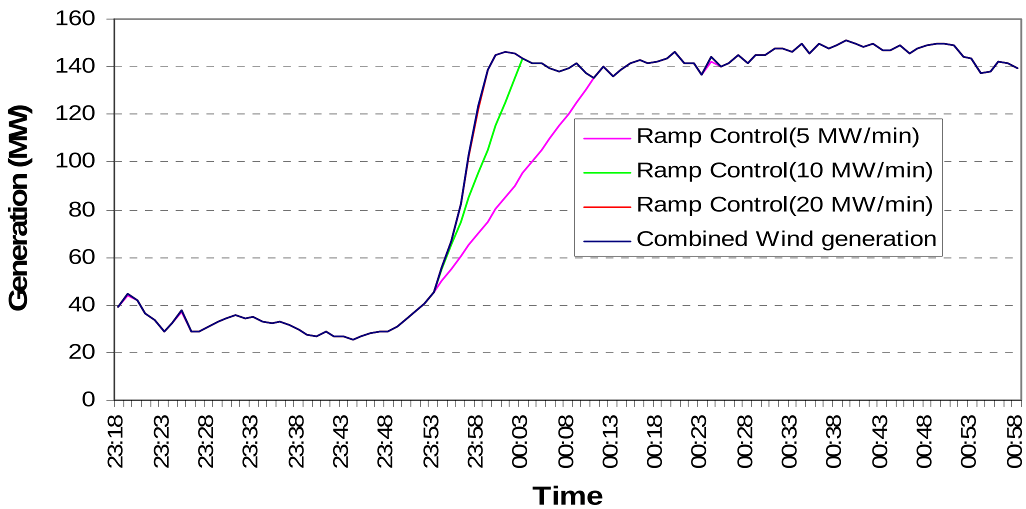

Figure 7 - Combined Te Äpiti and Tararua wind generation illustrated with maximum ramp up restrictions of 5, 10 and 20 MW per minute on 23 November 2004.

Similar analysis was conducted for the other events in Table 2 where positive increase in windfarm generation is greater than 50MW per minute during the period November 2004 to April 2005. Results from this analysis are summarised in Table 4. The figures illustrating the influence of the ramp rate control for these events are included in Appendix 7.

Date and time of the event	**Duration generation is constrained due to ramp control (in minutes)**			**Energy that would be lost due to ramp control (in MWh)**		
	For 5 MW/min	**For 10 MW/min**	**For 20 MW/min**	**For 5 MW/min**	**For 10 MW/min**	**For 20 MW/min**
15th Nov 2004, 01:00 to 02:00	22	11	11	18	6	0.7
23rd Nov 2004, 23:50 to 24:00	18	9	9	10	3	0.04
30 Dec 2004 16:45 to17:00	24	8	2	15	3	0.2
14th Feb 2005 11:30 to 12:00	13	4	0	4	0.3	0
14th Feb 2005 14:30 to14:45	14	8	4	11	5	1.3
25th March 2005 10:50 to11:05	13	4	0	3	0.3	0
Total loss over the 6 events	104	44	26	61	16.6	2.2

Table 4 - Summary of the ramp rate restriction of 5, 10 and 20 MW per minute on the combined Te Äpiti and Tararua wind generation for the six large events observed between November 2004 and April 2005.

Table 4 shows that for the event on the 23 November 2004, a ramp rate of 5 MW per minute will restrict the Te Äpiti and Tararua generation for 18 minutes with a total loss of 10 MWh. The total energy lost for the observed six events during the November 2004 to April 2005 period, is 61, 16.6, and 2.2 MWh for ramp rate restrictions of 5, 10 and 20 MW per minute respectively.

Ramp rate controls during wind events help the frequency keeping station to work within its capability margins. However, the benefit of stabilising the power system will result in a loss of wind energy during those events.

The EGRs currently place no specific obligations for intermittent generation to have ramp rate control. The WGIP will investigate what, if any, Asset Owner Performance Obligations (such as ramp rate controls) should apply to wind generation.

6.2 Improvements in Forecasting Accuracy

Inaccurate forecasts affect participants in the electricity market and the ability of the System Operator to meet the Principal Performance Obligations set out in Part C of the EGRs. Inaccuracy in forecasting affects participants by increasing uncertainty in trading outcomes. The security impact of greater inaccuracy in the schedule is the increased risk of transmission-constrained dispatch 'surprises' in real time.

Meridian has improved the accuracy of the Te Äpiti two hour ahead forecast since the previous report issued on 28 February 2005 (details on the forecasting methodology is contained in Section 5.1.3). It is understood that the MetService in conjunction with wind farm owners are developing methods to improve the wind farm forecasts.

The centralised forecasting of wind generation output may be more accurate than forecasts provided by individual wind generators. This is an area that will be investigated in the Electricity Commission's Wind Generation Investigation Project or that could be implemented by wind generators collectively as an initiative prior to the completion of the Wind Generation Investigation Project.

6.3 Improvements in automated dispatch processes

Automation of the dispatch process to produce dispatch instructions every five minutes and at any time when the wind generation output has changed materially away from the dispatched amount can help mitigate the effect of sudden large changes in wind generation output. Such automation also has benefits for the frequency keeper and for other generating plant as generation is re-dispatched more quickly to meet the changed power system conditions relieving the need for the frequency keeper and other generating plant to compensate for the sudden change in wind generation output.

6.4 Changes to Frequency Keeping

The highest rates of change observed in the output of Manawatu wind generation are greater than the current minimum requirements for frequency keeping stations (i.e. 10 MW per minute). While some frequency keepers can provide a more rapid rate of change, frequency keepers are contracted to provide only the minimum rate of change. In addition, the magnitude of some changes (around 100 MW) exceeds the contracted and dispatched MW frequency keeping band at this time (50 MW).

Options immediately available to the System Operator include increasing the minimum requirements for frequency keeping service providers and increasing the amount of frequency keeping procured. This is likely to increase the costs of the frequency keeping service. Another option is a requirement for ramp rate controls on wind turbines (which has been discussed previously). The implementation of Automatic Generation Control is another option.

6.5 Transmission Constraints

Power system capability limits can be revised in light of the observed rapid increases in wind generation output. It may also be necessary to revise operational policies and the means to ensure that transmission circuits do not exceed stated capability if Manawatu wind generation output was to rapidly increase during a contingent event.

A variety of measures can be used to manage the risk of exceeding power system capability limits when there are changes in wind generation. This includes automatic schemes to monitor transmission capacity and wind generation output and modify the output of wind generation (i.e. runback and inter-trip schemes). In the absence of any other controls applied by asset owners, constraints will need to be applied in power system operation. Constraints can be used to:

- Dispatch generation so that the circuits in question will not exceed stated capability for a sudden increase in Manawatu wind generation output or constrain off Manawatu wind generation at the times when there is a risk of these circuits exceeding stated capability.
- Restrict the rate at which wind generating units change output.

6.6 Changes to dispatch of must run generation

Wind generation is effectively treated as zero priced generation in the scheduling and dispatch process. Wind generation is currently not bid into nor accounted for in the current must-run dispatch process. This increases the likelihood that some must-run generation is not dispatched with consequent spilling of water or the incurring of high starting and stopping costs). Interim rule changes to either the must run auction process or the way in which wind generation is treated by SPD will be considered as part of interim Rule changes. This is an area that will also be investigated in the Electricity Commission's Wind Generation Investigation Project.

7 Increased installed wind generation capacity in the Manawatu region and North Island

The first part of the analysis in this report illustrates the current effect of wind generation in the Manawatu region on the power supply of New Zealand. Consents for further wind generation in the Manawatu region have been sought and some have been gained. It is likely, that the new wind generation in the Manawatu region may show a similar correlation to the strong correlation observed between the Tararua and Te Äpiti wind farms.

There is currently over 150 MW of installed wind generation capacity in the Manawatu region (Te Äpiti and the Tararua North and South wind farms). Resource consents have been gained for the Tararua III wind farm (93 MW) and the Te Rere Hau wind farm (48.5 MW). As a result, it is likely that there will be an additional 140 MW of installed wind generation capacity in the Manawatu region in the future. There is likely to be 300 MW of installed wind generation capacity in close proximity to the Manawatu gorge.

7.1 Effect on Wind Power Variability

The number of five minute changes of magnitude 25 to 50 MW for the months of December 2004 through to March 2005, and the number of five minute changes greater than 50 MW for the months of November 2004 through to March 2005 are summarised by month in Table 5. The five minute changes of magnitude 25 to 50 MW are categorised into increases or decreases in combined wind farm generation.

The total number or 25 to 50 MW events recorded was 56 over the 4 month period.

Month	Number of increasing 25-50MW events	Number of decreasing 25-50MW events	Number of >50MW events
November 2004	Not investigated	Not investigated	2
December 2004	11	11	1
January 2005	5	0	0
February 2005	7	7	2
March 2005	9	6	1

Table 5 - The number of 25 to 50 MW and greater than 50 MW five minute generation events for the combined Te Äpiti and Tararua generation

This information is shown in Figure 8 (this graph is also contained in Section 3, variability, as Figure 1). An explanation of the events is also contained in Section 3.

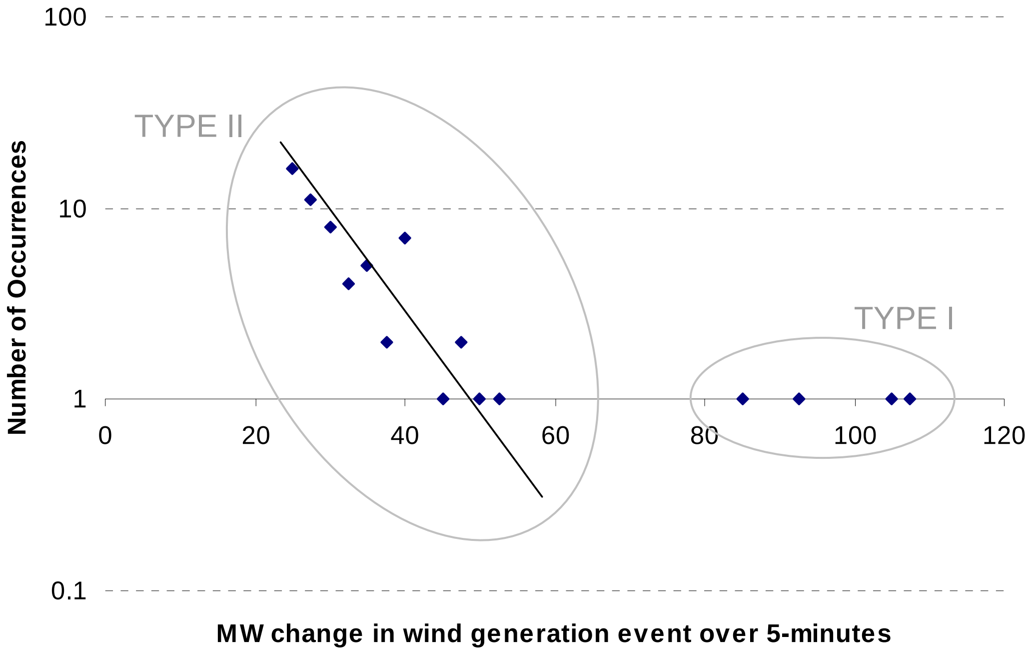

Figure 8- The number of 5 min changes greater than 25 MW

If a similar correlation is expected between the existing generation and new generation as is currently observed between the two existing wind farms, the size (MW change in five minutes) of the Type I events will be expected to increase proportionally as more wind generation capacity is added. Hence events that are 66% of the current capacity of the wind farms will increase from 100MW to 200MW if the output of the wind farms were to increase from 150MW to 300MW. The analysis has shown that this type of event would be expected to occur around 10 times each year.

The size of the Type II events would also be expected to increase with the addition of further wind generation capacity in the Manawatu region. If the new wind generation was strongly correlated with the existing wind generation then this type of variability would be expected to increase proportionally. Hence the 12 forecast Type II events each year of a change of around 33% of installed wind capacity in five minutes can be expected to increase from 50 MW in size to 100 MW if the output of wind generation in this area were to double.

If the new wind generation is not strongly correlated then an increase in this type of variability would still be expected, but to a lesser degree.

7.2 Effect on power system operation

If the amount of installed wind generation in the Manawatu region were to double, it is likely that increases in wind generation output of over 200 MW in five minutes will be observed (two events of greater than100MW in five minutes were observed in this analysis). Changes of this speed and magnitude would exceed the capability of most frequency keepers and the ability of the System Operator to re-dispatch in time to prevent a sizeable frequency excursion. The number of generators able to offer frequency keeping services with a higher band of 100 MW around its set point is limited. In reality there is likely to be only one possible provider, not a desirable outcome in a competitive market situation.

Changes to the way in which frequency keeping reserves are managed and costs allocated are likely to be required to ensure that government objectives set out the Government Policy Statement are met. The cost of constraining on/off a frequency keeping station to maintain the normal frequency band (49.8 to 50.2 Hz) is an additional cost to the industry.

7.2.1 North Island

There is currently just less than 170 MW of installed wind generation capacity in the entire North Island. Resource consents for another 210 MW of wind generation in the North Island have been granted. Resource consents for an additional 560 MW of wind generation have been applied for. Responses from the Request For Information on wind generation (put out in July 2005) indicate that a further 370 MW of wind generation is being considered.

It is likely that the amount of installed wind generation in the North Island will more than double within the next two years as the consented wind generation is commissioned. The amount of wind generation capacity installed in the North Island in three to five years time could potentially be in the range of 850 MW to 1300 MW.

The correlation between changes in wind generation output in different regions has not yet been determined. It would be reasonable to assume that the addition of further wind generation capacity in the North Island will lead to an increase in the frequency of occurrence and magnitude of sudden large changes in wind generation output. It is also reasonable to assume that the accuracy of the forecasts of the new wind generation output will be similar to the accuracy of the Te Äpiti forecast.

It is possible that the Type I events (sudden large changes in Manawatu wind generation output that occur during specific weather conditions) are unique to the region and the location of the wind farms. If this is the case then new wind generation outside of the Manawatu region will not add to the size of frequency of occurrence of these events.

It is likely that new wind generation output will demonstrate variability similar to the Type II events observed in the Manawatu region. If it is assumed that the new wind generation output variability is similar to what has been observed in the Manawatu then sudden large changes in North Island wind generation output of between 200 MW to 400 MW over five minutes might be expected to occur on a monthly basis if the installed wind generation capacity in the North island was in the range 850 MW to 1300 MW. This is based on characteristics of the Type II events observed at Te Äpiti (sudden changes of around 30% of installed capacity occurring 12 times a year). This is consistent with information provided by a wind generator for wind speeds measured at the same times for sites in a number of regions across New Zealand. Changes of this size will have significant implications for the management of frequency and transmission circuit loadings and potentially voltage management and other power quality issues.

If it is assumed that the forecast accuracy of new wind generation output was similar to that of Te Äpiti then the inaccuracy in the total of the forecasts for wind generation output in the North Island could be greater than 250 MW for 10% of the time. This assumes that 10% of forecasts will have an error of greater than 33% of installed capacity (similar to Te Äpiti forecast accuracy) but that some of the errors will cancel out. A forecast inaccuracy of 250 MW is equivalent to the size of a Huntly Power Station generating unit. Forecast uncertainties of this size are likely to have a significant impact on the offers and bids made by generators and participants.

In formulating interim rule changes, the Tactical Project will consider what rule changes will be required to manage the effects of the committed and existing wind generation along with that likely to be committed and operating within two years. The scope of the WGIP is to consider power system operation and market changes required to manage wind generation capacity that will be installed over the next 10 years.

8 Conclusions

Analysis of the variability of Manawatu wind generation indicates:

- Sudden large changes in wind generation output (of 50 MW or greater in five minutes) are likely to occur around 20 such events per year for the current installed wind generation capacity in the Manawatu region.
- Large changes in wind generation output over a short period may cause power system frequency excursions.
- The observed rates of change in Manawatu wind generation are at times greater than the minimum ramp rates requirements for frequency keeping service providers.
- The size of the changes in Manawatu wind generation is at times greater than the typical frequency keeping MW band dispatched.
- An improvement in the accuracy of Te Äpiti's two hour forecasts has been observed since January 2005. . There have been no improvements in six and 12 hour forecasts.

In addition to the observed effect on power system frequency, sudden changes in Manawatu wind generation cause changes in power flow across the transmission grid which may cause assets to exceed their stated capability. Inaccuracy in provided forecasts of wind generation reduces the System Operator's ability to manage the power system securely and increases uncertainty for other generators in the planned dispatch of their plant.

It must be noted that some of the observed impacts (e.g. weather condition related sudden large changes and correlation between wind farm outputs) may be unique to Manawatu wind generation and may not occur with wind generation installations in other parts of New Zealand.

Overall, the current effects of Manawatu wind generation variability on the operation of the power system and the electricity market are manageable using the policies and means available to the System Operator set out in the policy statement in Part C of the EGRs. However, any increase in the amount of Manawatu generation means that the System Operator will have to review the policies and means in the policy statement along with the dispatch rules in Part G.

The System Operator will be identifying and proposing rule changes, where required, as part of the next stage of the Tactical Project so that the impacts of additional wind generation can be managed to ensure the integrity of the power system ahead of any further changes from the WGIP. The process of identifying and proposing any required rule changes is planned to be completed in October 2005 and submitted to the Electricity Commission for processing through its rule change processes.

Appendices

Appendix 1 Data series used in the study

This section describes the data used in study.

(a) Wind Generation output data used in this study

The study used 10 second SCADA output data from Te Äpiti, and Tararua wind farms. Note that the Tararua wind farm series has been aggregated from a “Tararua North” and “Tararua South” data series. For most analyses the generation data from these three series was combined to form a 10 second total wind generation series.

The Tararua generation data is collected in 10 second samples. However as this information is sourced from a 60 second value, each 10-second generation value is repeated a further five times.

(b) Meridian offers of Te Äpiti generation

Meridian offers Te Äpiti generation into the Electricity Market. The Te Äpiti offers at 12, 6 and 2 hours prior to the current trading period were analysed in this study. Offers are half-hour averages. These offers were compared with metered generation at Te Äpiti for the same half-hour.

(c) Trustpower forecasts of Tararua generation

As the Tararua wind farm is embedded, Trustpower was not required to offer in Tararua wind farm forecasts. However as an interim arrangement until their forecasts could be offered to the market (and the appropriate modifications made to the Load Forecast application), Trustpower submitted Tararua forecasts to the System Operator (as an email attachment) four times per day. These forecasts are half-hour averages and were compared with metered generation at Tararua for the same half-hour.

The forecasts were analysed for November 2004 only due to the effort required to compile the various 6 hourly offer files over a monthly period. By analysing the November forecasts we are also able to compare the Tararua results against those already analysed for Te Äpiti.

(d) North Island frequency data

The North Island 10-second frequency data was used in investigating the influence of the large wind generation events on the North Island frequency and frequency keeper. Island frequency is measured in Hertz (Hz).

(e) Frequency Keeper and dispatch instructions

This information was sourced from the Transpower TPIX database. The dispatch instructions are time stamped at the time they are issued. The dispatched frequency keeper and frequency keeper band width is identified by trading period.

Appendix 2 Observed Large Events

For the period November 2004 to April 2005 there were six events where the combined Manawatu wind generation exceeded 50 MW in any five minute interval. These events are summarised in Table 6.

Date/Time	Greatest output change (MW) and time interval	Max rate of increase per 5-min (MW)	Max rate of increase per min (MW)	Max rate of decrease per min (MW)	No of mins rate of increase >10 MW	No of mins rate of decrease i >10MW
15 Nov/1:00	140MW in 13 mins	105	32.9	11.9	6	< 1
23 Nov/23:50	110MW in 11 mins	85				
30 Dec/16:45	130MW in 12 mins	93				
14 Feb/11:30	70MW in 12 mins	53	14.6	12.3	4	<1
14 Feb/14:30	120MW in 10 mins	109	47	12	4	<1
25 Mar/10:50	70MW in 8 mins	50	16.9	-	3	-

Table 6 - Summary of the combined Tararua and Te Äpiti wind generation events greater than 50 MW in five minutes, for the period 1 November 2004 to 30 April 2005.

Event 1 – 15 November 2004

This event occurred between 1:00 and 2:00 and consisted of a steep rise of about 140 MW in 13 minutes, followed by a more gradual fall. Figure 9 is a graph of the total power output of the Tararua and Te Äpiti wind farms during the event.

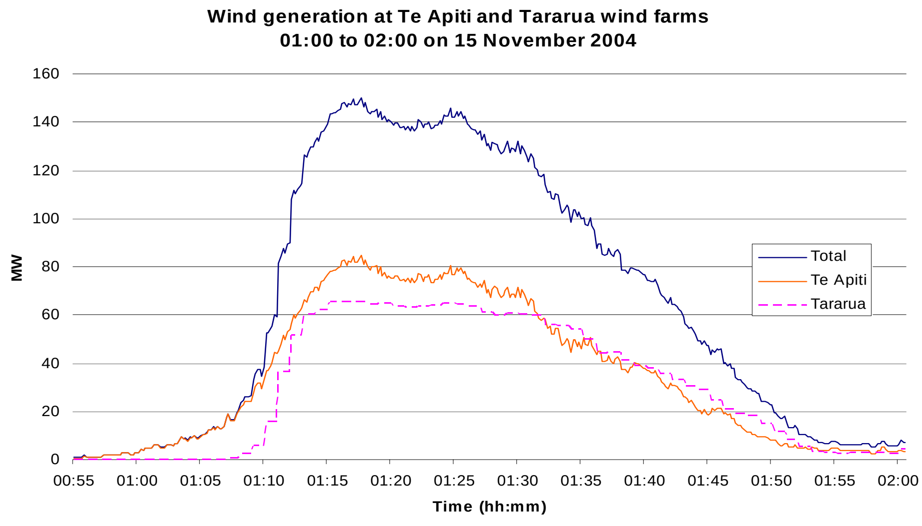

Figure 9 - Graph of the combined power output of Tararua and Te Äpiti wind farms between 00:43 and 2:09 on 15 November 2004.

Event 2 – 23 November 2004

This event occurred at 23:50 and consisted of a steep rise of about 110 MW in 11 minutes (see Figure 10).

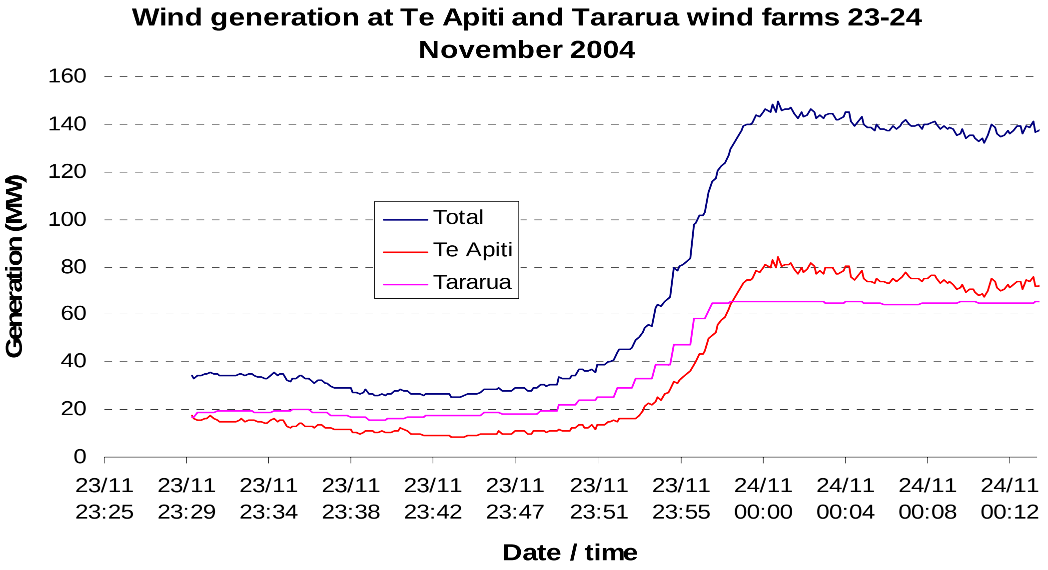

Figure 10 - Graph of the combined power output of Tararua and Te Äpiti wind farms on 23 November 2004

Event 3 – 30 December 2004

This event occurred at 16:45 and consisted of a steep rise of about 130 MW in12 minutes (see Figure 11).

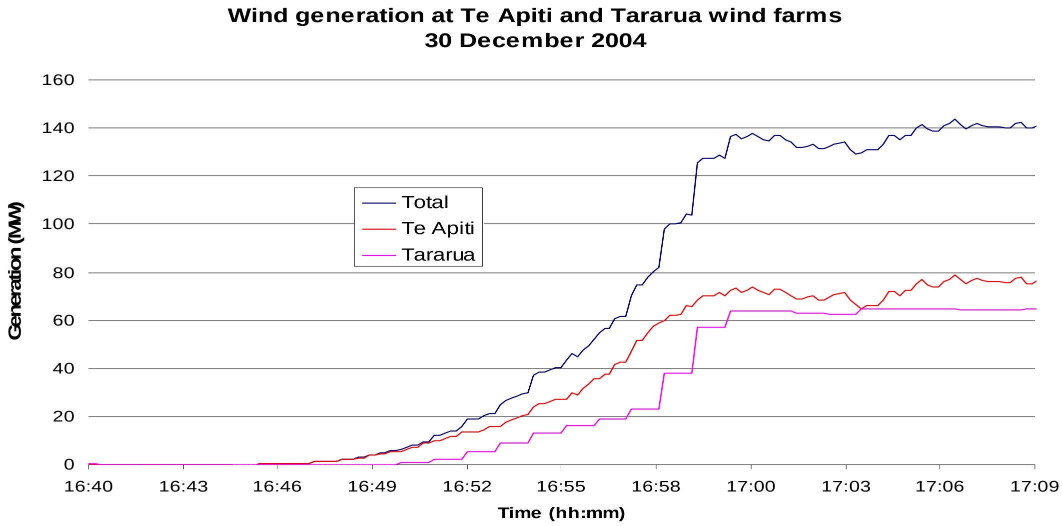

Figure 11 - Graph of the combined power output of Tararua and Te Äpiti wind farms on 30 December 2004.

Event 4 – 14 February 2005 at 11.30

This event occurred at 11:30 and consisted of a steep rise of about 70 MW in 12 minutes (see Figure 12).

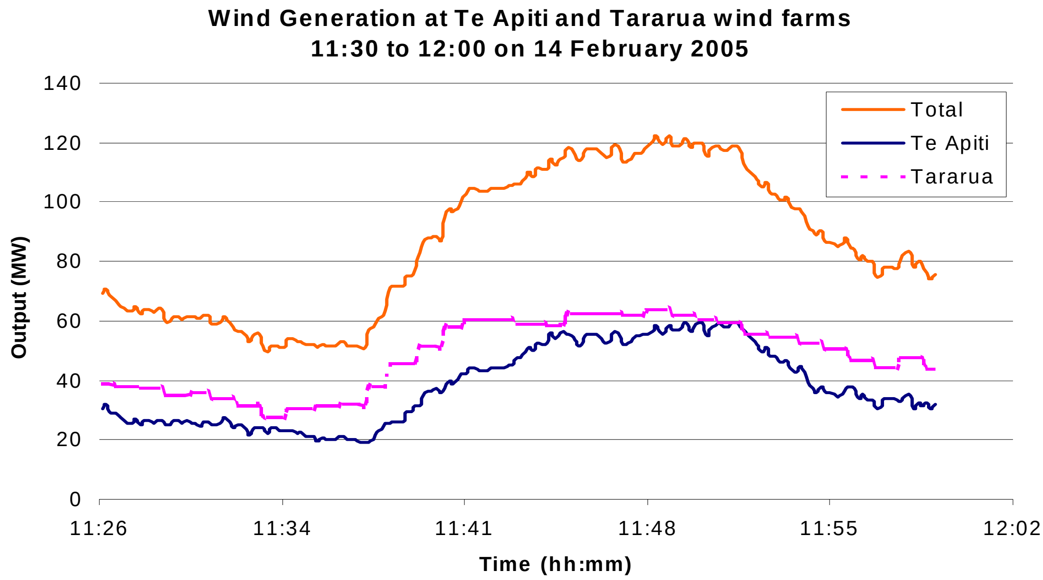

Figure 12 - Graph of the power output of Tararua and Te Äpiti wind farms on 14 February 2005 at 11:30

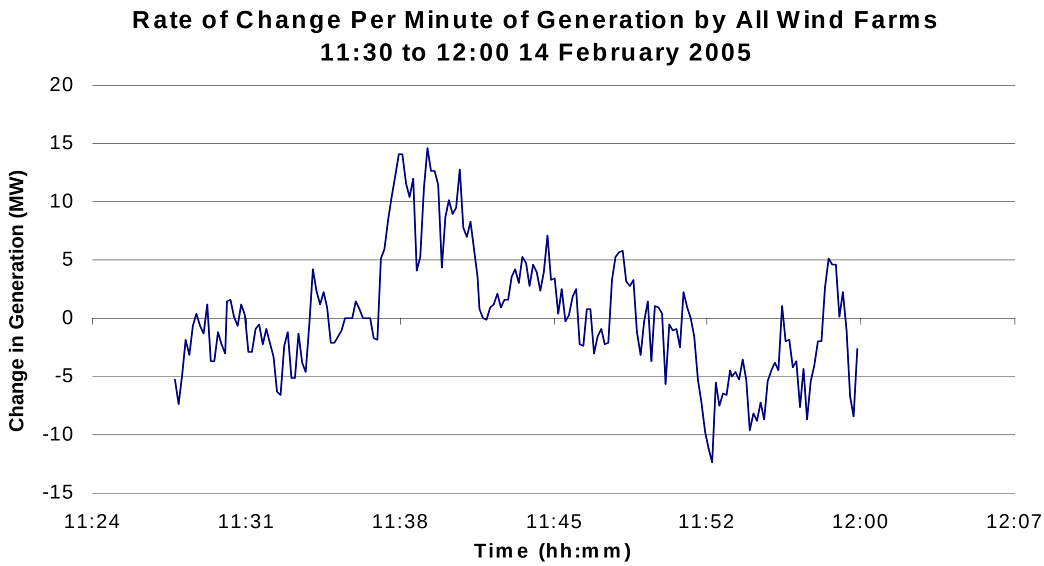

Figure 13 - Graph of the rate of change per minute of generation on 14 February 2005 at 11:30

The maximum five minute change for this event was a 53 MW ramp up followed approximately fifteen minutes later by a ramp down of 38 MW.

The combined generation ramp rate per minute reached a maximum value of 14.6 MW during this event and stays above 10 MW per minute on and off for approximately four minutes (see Figure 13). The average ramp up rate over 13 minutes is 4.2 MW per minute.

From the peak of the combined wind generation of 122 MW, the ramp down to 80 MW occurs over a period of 10 minutes. The maximum (down) ramp rate is 12.3 MW per minute, but the rate of change does not exceed 10 MW per minute for more than one minute.

Event 5 – 14 February 2005 at 14.30

This event occurred on the same day as Event 4 and occurred 3 hours later at 14:30. The event consisted of a steep rise of about 120 MW in 10 minutes, followed by a more gradual decrease (see Figure 14).

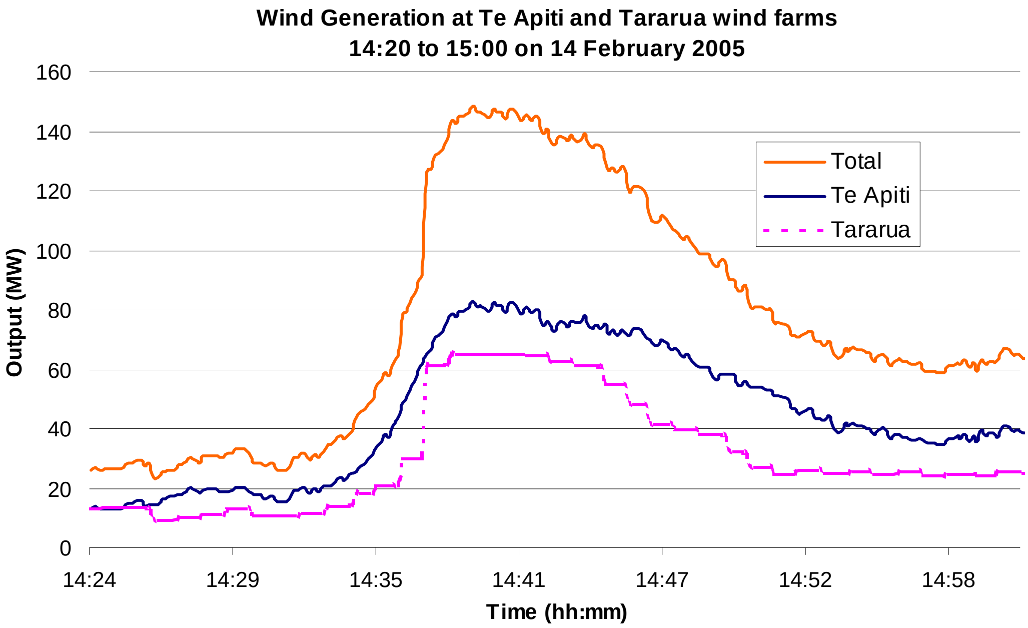

Figure 14 - Graph of the combined power output of Tararua and Te Äpiti wind farms on 14 February 2005 at 14:30.

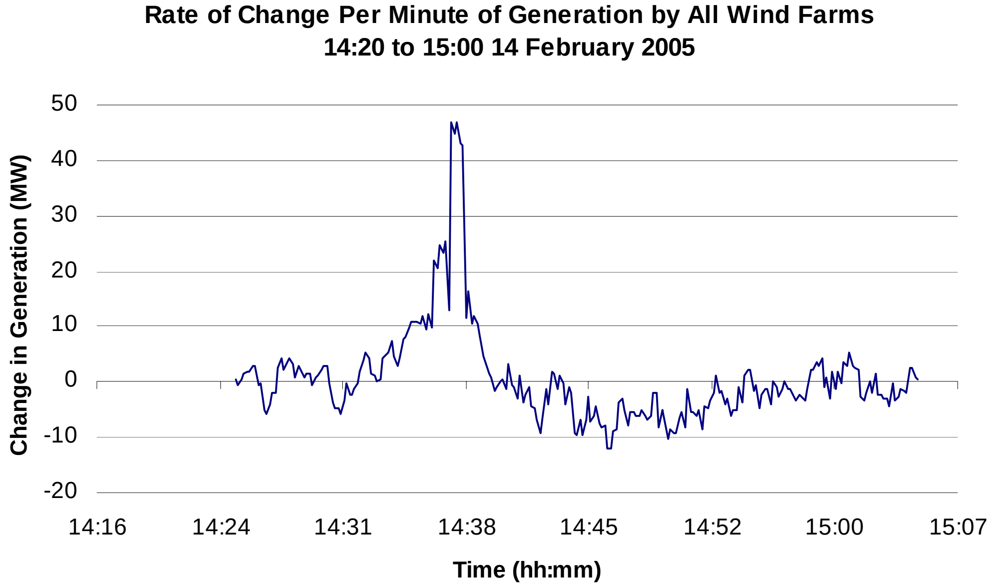

Figure 15 - Graph of the rate of change per minute of generation on 14 February 2005 at 14:30

The combined generation ramp rate per minute reached a maximum value of 47 MW during this event (see Figure 15). The ramp rate stays above 10 MW per minute for approximately four minutes and has an average ramp up of 13 MW per minute over seven minutes. This ramp up exceeds the minimum frequency response rate (of 10 MW per minute) and consequently the response capability of some frequency keepers.

From the combined wind farm peak generation of 148 MW, the ramp down to the final value of 60 MW occurs more gradually, over a period of 17 minutes (see Figure 14). The maximum (down) ramp rate is 12 MW per minute, but the rate of change does not exceed 10 MW per minute for more than one minute.

To maintain the North Island frequency the frequency keeper and / or other dispatched generation, would have had to reduce generation by 109 MW in five minutes, and then ten minutes later pick up 41 MW of generation in five minutes.

Event 6 – 25 March 2005

This event occurred at 10:50 and consisted of a steep rise of about 70 MW in 8 minutes (see Figure 16).

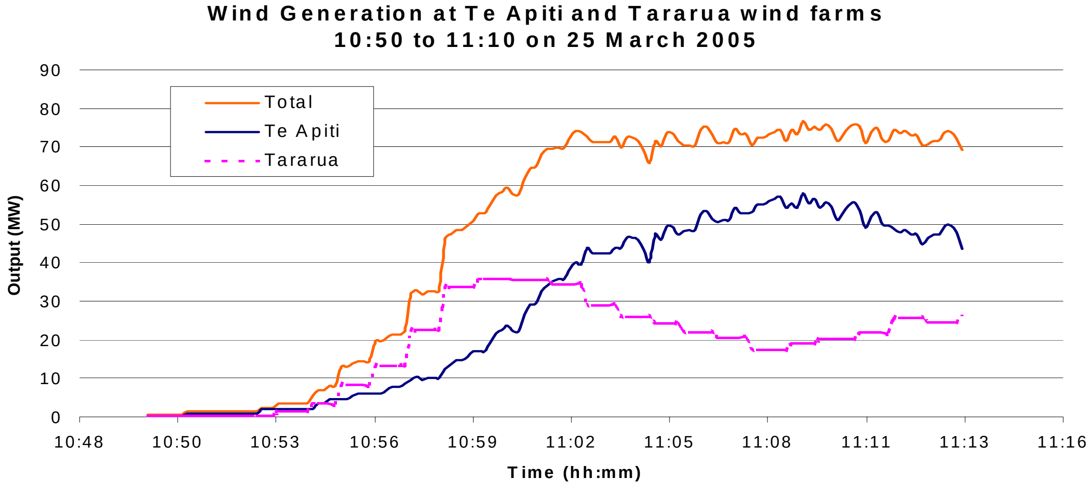

Figure 16 - Graph of the combined power output of Tararua and Te Äpiti wind farms on 25 March 2005

The correlation between the generation outputs of the wind farms is not as strong for this event as the correlation seen in the previous 2 events. For this event, the increase in wind speed occurs over a period of ten minutes and causes the combined wind farm outputs to increase from 1 MW to a peak of 74 MW.

The maximum five minute change during the event was a ramp up of 50.4 MW.

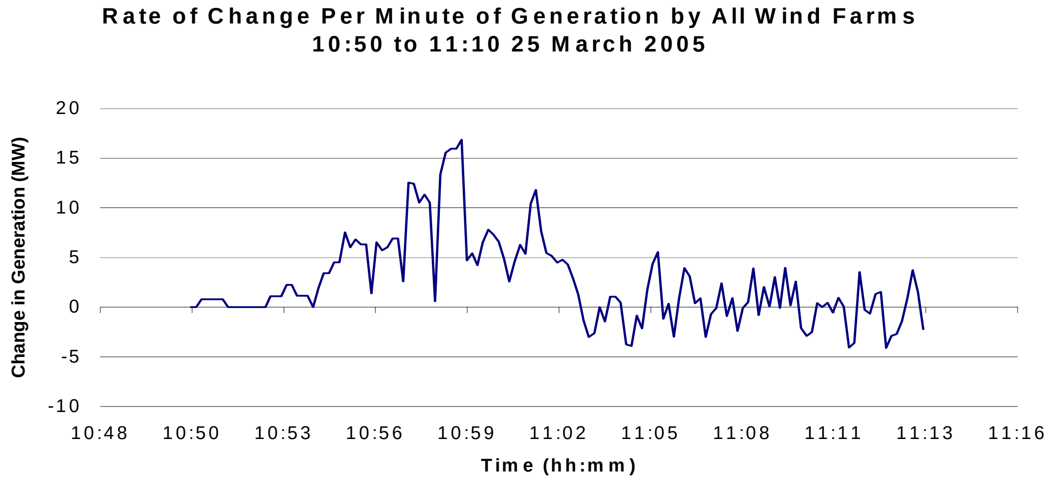

Figure 17 - Graph of the rate of change per minute of generation on 25 March 2005

The combined wind generation ramp rate per minute reached a maximum value of 16.9 MW during this event (see Figure 17). The ramp rate stays above 10 MW per minute for approximately three minutes, with another brief peak of 11.8 MW per minute at 11:01, and has an average ramp up of 6.2 MW per minute over ten minutes.

Appendix 3 Metrological Circumstances of the Wind Generation Surges

Introduction

Transpower requested the New Zealand Metrological Service (MetService) to investigate certain wind events observed at the Tararua and Te Äpiti wind farms. There was interest in the meteorological circumstances of these selected events, whether such events can be anticipated, the time scale of their predictability, and the frequency of occurrence.

The Events

Transpower identified six recent events which are listed in Table 7 for investigation.

Event Number	Date and Time	Approximate output change, and interval
1	15 Nov 2004, 01:00 to 02:00	140MW in 13 min increase (105MW in 5 minutes)
2	23 Nov 2004, 23:50 to 24:00	110MW in11 min increase (85MW in 5 minutes)
3	30 Dec 2004, 16.45 to 17.00	130MW in 12 min increase (93MW in 5 minutes)
4	14 Feb 2005, 11:30 to 12:00	70MW in 12 min increase (53MW in 5 minutes)
5	14 Feb 2005, 14:30 to 14:45	120MW in 10 min increase (109MW in 5 minutes)
6	25 Mar 2005, 10:50 to 11:05	70MW in 8 min increase (50MW in 5 minutes)

Table 7 - List of Large events selected for investigation. Events 1 and 5 consist of an increase in output followed shortly by a decrease of about the same magnitude. The other events are all simple increases.

These events are described in this report, though Events 4 and 5 are considered together as they occurred only 3 hours apart.

Observations

The observations used to investigate these events are from two main sources:

1. MetService operated meteorological stations in the vicinity of the Te Äpiti and Tararua Wind Farms (Ohakea Aerodrome, Palmerston North Airport, Levin

and, Paraparaumu Airport). All of these stations are automatic weather stations except Ohakea where the observations are read by Air Traffic Control officers who maintain a 24 hour per day watch. The observations are made at hourly intervals on the hour, and the wind speeds and directions are 10-minute means over the 10 minute interval immediately before the hour. The anemometers at MetService stations are on meteorological standard 10-metre masts with generally good exposure. These stations are at low altitude. Ohakea is at 50 metres; Palmerston North is at 45 metres; and Paraparaumu and Levin are near sea level.

2. Meridian Energy has provided wind data from their two meteorological sites at Te Äpiti. The two sites are identified as TapM1 and TapM2, and are at 396 and 345 metres above sea level, respectively. The masts are a few hundred metres apart, and the anemometer heads are 70 metres above ground level which is approximately the hub height for the generator machines. The wind observations are at 10 minute intervals and are 10-minute mean wind directions and speeds.

In addition, Trustpower has also provided wind data from one mast located in the Tararua Wind Farm. This station is identified as Tararua. The anemometer height is about 40.5 metres above ground level, the same as the generator hub height.

Atmospheric Modelling

MetService operates an automated atmospheric prediction system[8] on various domains over and within New Zealand. During the period that these events occurred both Meridian and Trustpower were receiving hourly wind forecasts for a selected location in the vicinity of their respective wind farms at Te Äpiti and Tararua. For Te Äpiti the wind was forecast at heights of 15, 30, 45 and 75 metres above ground, and

[2] The prediction system is MM5, and the MetService implementation is known as CHAMP. The PSU/NCAR mesoscale model (known as MM5) is a limited-area, nonhydrostatic, terrain-following sigma-coordinate model designed to simulate or predict mesoscale atmospheric circulation. The model is supported by several pre- and post-processing programs, which are referred to collectively as the MM5 modelling system. The MM5 modelling system software is mostly written in Fortran, and has been developed at Penn State and NCAR as a community mesoscale model with contributions from users worldwide.

Mesoscale

The term mesoscale is a size scale referring to weather systems smaller than synoptic scale systems but larger than storm-scale systems. Horizontal dimensions generally range from around 50 miles to several hundred miles. Squall lines, Mesoscale Convective Complexes, and Mesoscale Convective Systems are examples of mesoscale weather systems.

Mesoscale can be further divided to subclasses

1. Meso-gamma 2-20 km, deals with phenomena like Thunderstorm convection, complex terrain flows (at the edge to micro-scale, also known as storm-scale)
2. Meso-beta 20-200 km deals with phenomena like sea breezes
3. Meso-alpha 200-2000 km fronts, deals with phenomena like low pressure systems, at the edge of synoptic scale

70 metres above ground at Tararua. These forecasts were derived from the output of the New Zealand 12 kilometre domain. This domain is known as "nz12kmN".

For this investigation the atmospheric prediction system was run over a 5 kilometre domain known as "wgiwrp5kmN" covering the area from north Taranaki and Hawkes Bay to Buller and the Kaikoura Coast.

It should be borne in mind that the atmospheric prediction system contains a representation of the real world and the laws of physics that apply to it. For example, even on a grid as fine as 5 kilometres the representation of terrain, and especially rugged terrain, is very approximate. Each station location is projected onto the approximation of the terrain in the model resulting in the model station altitude being different to the physical station altitude. Stations on ridges will have a lower model altitude than its actual station altitude, and stations in valleys or gullies will have a higher model altitude than its actual station altitude.

Summary of Events

Event 1: 15 November 2004

Soon after 01:00 on 15 November 2004 the wind speed spike, and consequent generation surge from the combined wind farms at Tararua and Te Äpiti was associated with the movement of a cold front over the area. The wind direction changed from east of the axis of the main North Island ranges to west of the axis.

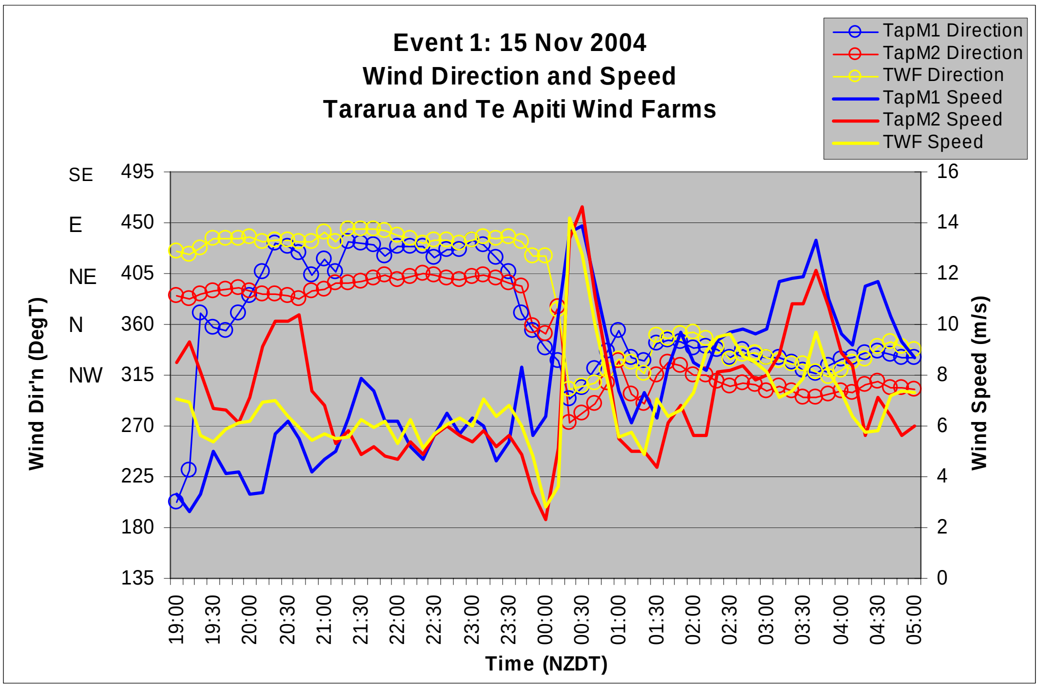

Figure 18 - Graph of wind observations from two anemometers at Te Äpiti (TapM1 and TapM2) and one at Tararua Wind farm. Wind speed is represented by the solid heavy lines and the right vertical scale, and direction is represented by the small circles joined by light lines and the left vertical scale. NOTE : The x-axis on in Figure A2.1 is shown as New Zealand Daylight savings Time (NZDT) which at this time of the year is 1 hour behind New Zealand Standard

Time (NZST) – the actual clock time which is time on which the rest of the report has been based.

Referring to Figure 18, the initial dip in wind speed is probably because the wind at that time is blowing parallel to the Ruahine Ranges to the north-northeast of the wind farms. The sudden increase and following decrease coincident with the passage of the cold front is probably caused by a combination of the wind direction becoming perpendicular to the alignment of the ranges, and a stability condition in the frontal zone. After the front has passed, the stability condition no longer exists in the vicinity of the wind farm, but the wind direction remains more or less perpendicular to the ranges.

The model run over the wgiwrp5kmN domain predicted the sequence of events and the timing remarkably well. This event shows the value of high time resolution wind speed forecasts and the possible use of a sequence of a wind field forecast chart to track the approach of significant changes in wind regime.

Event 2: 23 November 2004

Late in the evening on 23 November 2004 a sudden increase in the wind speed, and consequent generation surge from the combined wind farms at Tararua and Te Äpiti, was associated with the movement of a cold front over the area. The wind direction at low altitude stations changed from east of the axis of the main North Island ranges to west of the axis.

At the wind farm sites the sudden increase in wind speed occurred as the wind direction changed from blowing from the east of the main divide to blowing from the west. This increase was temporary, only lasting about an hour, but was part of a trend of increasing wind speed.

The atmospheric modelling system had a representation of a cold front crossing the southern North Island at approximately the right time. However, the details of the low wind speed ahead of the front, the temporary wind speed increase with the front, and strong westerlies behind the front were not well represented in the time series forecasts for individual stations either on the plains or at the wind farms.

Event 3: 30 December 2004

In the mid to late afternoon on 30 December 2004, the sharp increase in wind speed and the consequent surge in combined power output from the Tararua and Te Äpiti wind farms was caused by the cold front which moved eastwards across the lower North Island. As the front passed, the wind direction changed from east of the axis of the main North Island ranges to west of the axis.

The forecast was about an hour and a half ahead of actual events and the detail of the wind direction changes and speed changes that were observed are evident in the charts of the model output. However, there is no indication of these changes in the time-series forecasts for the wind farm locations. For the location and height of the wind farms, this event was not well forecast.

Event 4 & 5: 14 February 2005

The two events of wind speed increases, and consequent combined power output surges were associated with the eastward movement of a cold front across the southern part of the North Island. In this case the wind direction was from west of the axis of the main ranges throughout.

While the model indicates that there is a change in the wind speed (the gradual increase between 13:00 and 17:00.), the detail of the wind speed spikes at 11:30 and at 14:30 leading to the generation surges is absent.

Event 6: 25 March 2005

This surge in power generation was associated with the movement of a discontinuity of wind speed and direction across the southern part of the North Island.
In the operational charts this feature was marked as a cold front but there is little evidence supporting that classification.

Whatever the feature was, it was identified by the model. It was plainly depicted in the chart forms of the model output, and the time series forecasts conveyed a reasonably accurate forecast of the sequence and relative magnitude of the wind that was later observed. It is noted though that the forecast timing was somewhat ahead of actual events.

Conclusions and Discussion

All investigated events were associated with the movement of meso-scale meteorological features (such as cold fronts) over the wind farm areas. Two of the events were only a few hours apart and it was decided to treat them as parts of the same meteorological event. These features were discrete and coherent components of large-scale weather systems. That is, these events were all associated with recognisable features on the operational and published weather charts.

It is not known if all, or what types of meso-scale meteorological systems affect the near ground wind field in such a way that there are large fluctuations in total power output from these two wind farms.

The meteorological situations of all these events are essentially the same; large slow moving depression west of the South Island, and a frontal system moving eastwards across the southern part of the North Island.

A change in the direction of the wind flow across the axis of the main North Island mountain ranges is an important occurrence. For example, a situation where the wind is first blowing from easterly or northeast, and then blowing from northwest or westerly. As the direction gradually backs from east through north to west, when the wind direction is aligned with the main ranges the wind speed is temporarily reduced. Later when the direction becomes more or less perpendicular with the axis of the ranges, there is a fairly sharp increase in wind speed. It is not clear if this is due to the particular stability structure of the frontal zone in a cold front or a dynamical effect of the interaction of the changing wind direction and the topography (shape of the terrain). In fact it is probably a combination of both of these.

Early work for this report revealed that hourly time series atmospheric model data was inadequate to determine if the model had the potential to forecast the wind speed changes possibly leading to a power generation surge. Consequently higher resolution forecasts were sought. There was useful detail in wind forecast data at the higher time resolution of 10-minute intervals, but there some limitations with the forecast wind direction.

A chart (i.e. on a map) plot of the wind field is able to reveal relatively small changes in speed or direction that may be part of a coherent and persistent meteorological feature. A sequence of such plots, particularly if animated in a computer application is particularly useful for the detection of such changes, and to put a time series of forecast data for a location (or for several locations) into an area context.

Frequency of Occurrence

Daily weather charts for the year August 2004 to July 2005 were qualitatively inspected to determine an estimate of the frequency of occurrence of meteorological situations that may cause wind power generation surges at the combined wind farms at Tararua and Te Äpiti. The meteorological situation considered by the MetService to cause generation surges are those with a depression (low pressure centre) close to the west coast of the South Island, moving in a general southeast direction, and a cold front moving eastwards across the south of the North Island. It should be noted that all of the situations investigated in this report (that is the only ones that have been brought to the MetService's attention) have these characteristics. There may be other situations that cause rapid changes in wind speed on a space scale comparable with the size of the combined wind farms.

Table 8 lists the dates when the meteorological situation was similar to those in this report which caused wind power generation surges.

Month	**Dates**	**Comments**
August 2004	5, 6	
September 2004	2, 14, 28	
October 2004	5, 30	Also possibly 8, 18, 20, 25
November 2004	15, 23	Both discussed in this report
December 2004	18, 21, 30	30th discussed in this report
January 2005	None	
February 2005	14	Discussed in this report Also possibly 12
March 2005	25	Discussed in this report

April 2005	None	
May 2005	23, 30	
June 2005	22	
July 2005	15	

Table 8 - List of dates between August 2004 and July 2005 when the meteorological situation was similar to those that caused the wind power generation surges discussed in this report.

The meteorological situations that are known to cause power generation surges from the combined wind farms at Tararua and Te Äpiti occur fairly regularly once or twice per month.

Can these events be forecast?

The meteorological situations that cause these events are easily recognised and in general terms can probably be forecast with good success a day or two ahead of their occurrence by simple inspection of the freely published forecast weather charts. Precise timing and the estimation of the magnitude of these events is more difficult and requires high quality wind field, and specific point predictions. Even with these tools successful detection of a generation surge event is not always possible. In this analysis 3 out of the 5 events identified by Transpower where not at all well modelled with a model initialisation time as little as 12 hours ahead.

The MetService expects that with better modelling techniques being developed, better accuracy with the modelling of wind speed will be achieved. This will lead to greater success with the identification and timing of wind power surges.

Appendix 4 Correlation Analysis

The correlation between the Tararua and Te Äpiti wind farm generation was analysed for the sudden large events observed from November 2004 to March 2005. The four largest wind generation events (Type I events) have been investigated. Further, each which changed by at least 85 MW and up to 109 MW in five minutes.

The best fit line and corresponding correlation coefficient (r^2) were also determined from the 10-second generation data (Table 9). The r^2 value represents the (closeness of) fit between the two data series. An r^2 value of 1 would represent a perfect positive correlation between the two series and an r^2 value of 0 indicates no correlation between the two series. As summarised in Table 9, and as observed in Figure 19 to Figure 22 the correlation between the Tararua wind farm and Te Äpiti is very high during the four generation events analysed.

Event	**15 Nov 2004**	**23-24 Nov 2004**	**30 Dec 2004**	**14 Feb 2005**
r^2 value	0.92	0.99	0.91	0.91
Best fit line	Logarithmic (linear 0.85)	Logarithmic (linear 0.95)	linear	linear

Table 9- Correlation coefficient and best fit line for the large rapid wind generation events observed from November 2004 to March 2005

Figure 20 illustrates a close fit between the generation outputs of the two wind farms. The “levelling” at the top as observed in Figure 20 is caused due to the Tararua wind farm being at maximum output before that of Te Äpiti.

Figure 19, Figure 21 and Figure 22 illustrate a different relationship (fit) at the higher levels of generation. This may be due to the different physical characteristics of the respective plant, and / or wind exposure at the respective locations.

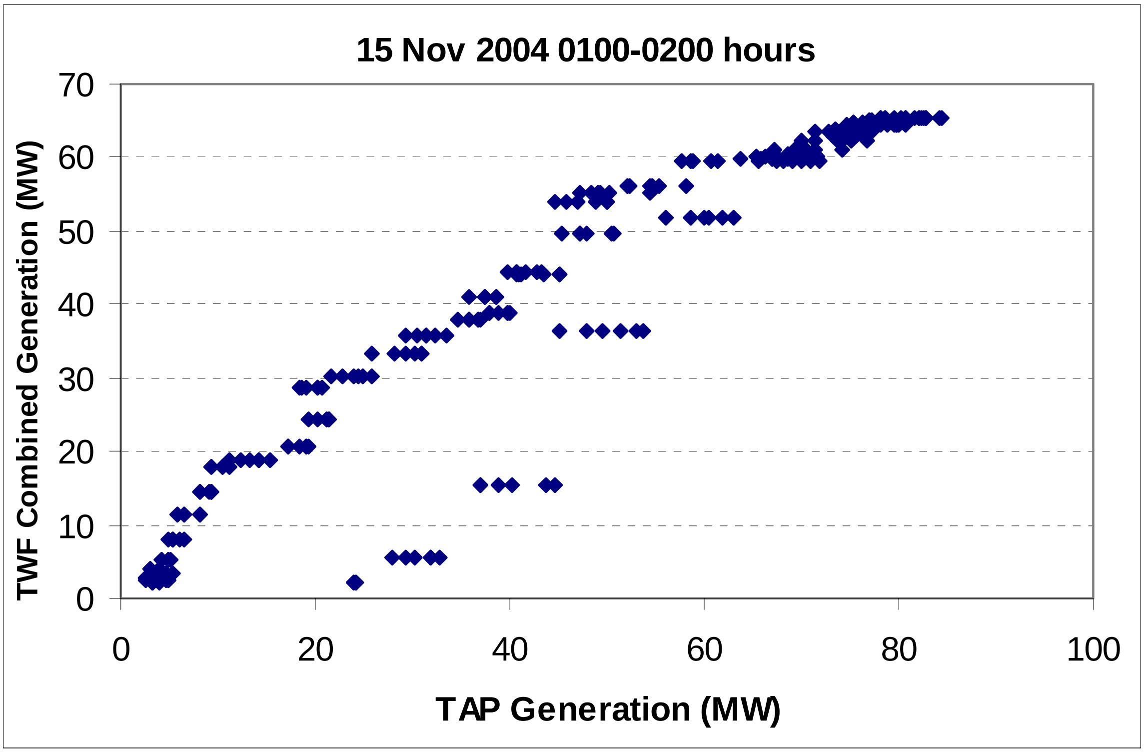

Figure 19 - Scatter plot for the Te Äpiti and Tararua wind generation illustrated for 15 November 2004.

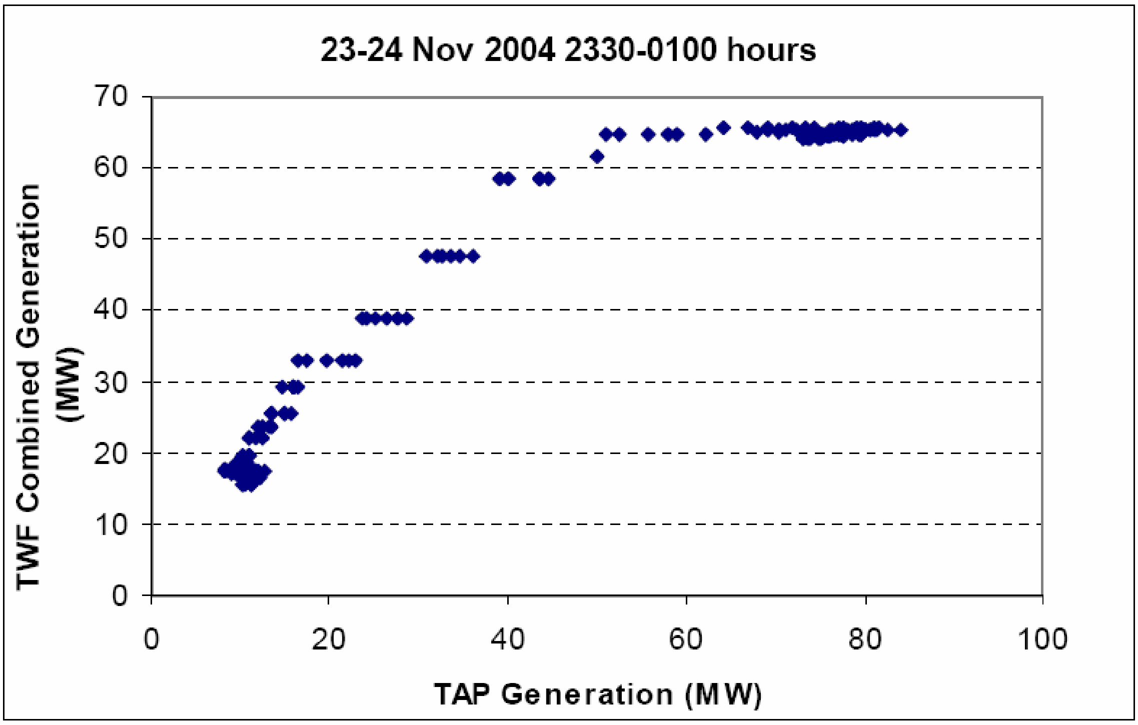

Figure 20 - Scatter plot for the Te Äpiti and Tararua wind generation illustrated for 23 November 2004

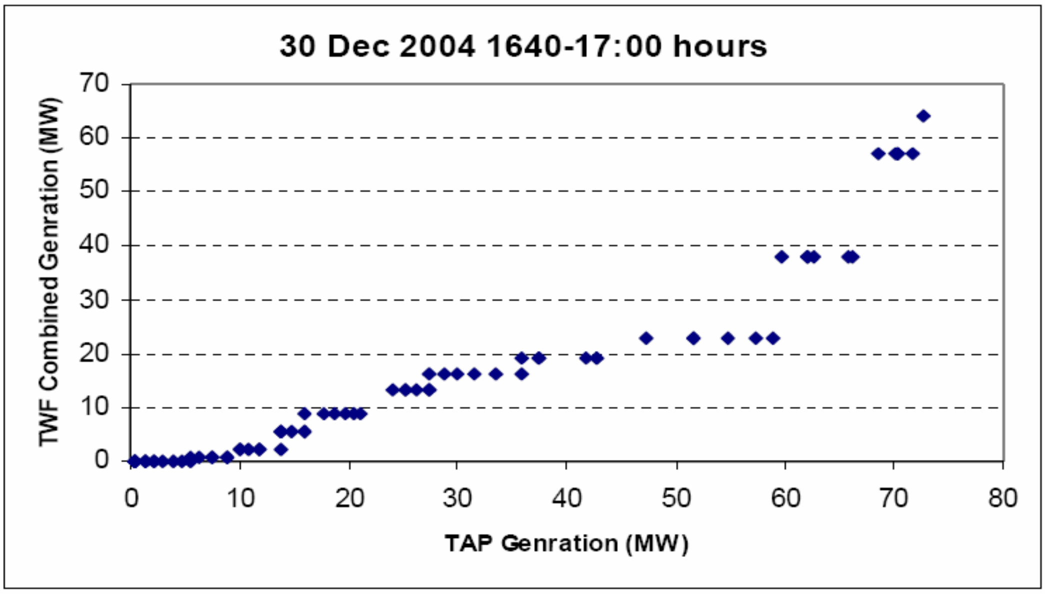

Figure 21 - Scatter plot for the Te Äpiti and Tararua wind generation illustrated for 30 December 2004.

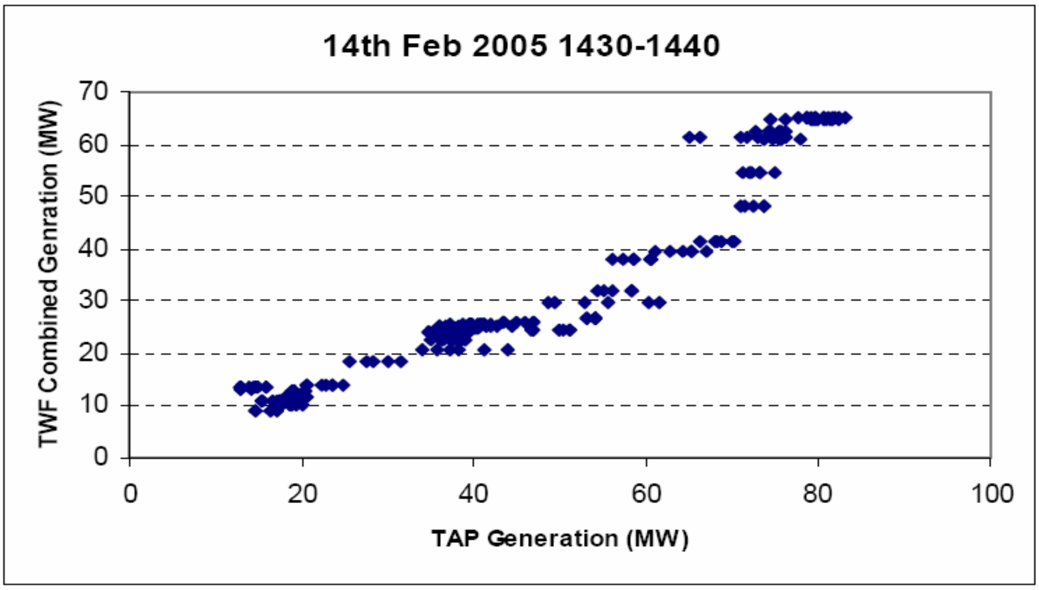

Figure 22 - Scatter plot for the Te Äpiti and Tararua wind generation illustrated for 14 February 2005. Note: As mentioned in the earlier Manawatu wind generation report the Tararua 10 second wind farm data is derived from 60 second values. In all the figures the influence of this anomaly is obvious by the "step" changes in the graphs. Thus the Te Äpiti generation changes every 10 seconds but the Tararua data remains unchanged for several time steps. A better fit of the data would be observed if the actual Tararua 10 second data was of better quality.

Appendix 5 Frequency Keeping Station response to Events

Event 1 – 15 November 2004

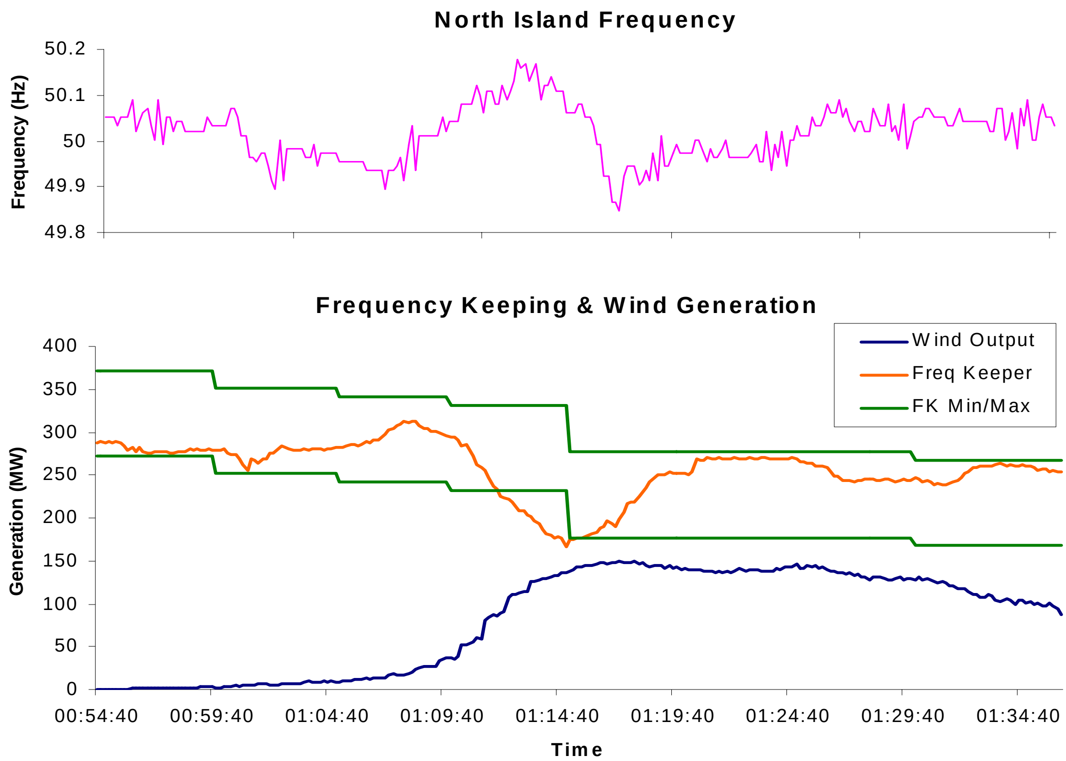

Figure 23 - North Island frequency, frequency keeping generation (and frequency bands) in response to the event on 15 November 2004

Figure 23 shows a rapid increase in wind generation on the 15 November 2004. During this event the total wind generation increased by a maximum of 105 MW over 5 minutes and 150 MW in 20 minutes. From Figure 23, it is evident that in the initial period nearly all of this increase in generation is offset by the frequency keeper which is reducing output in response to the increase in the North Island frequency. During this time the frequency keeper moves outside the frequency band and the North Island frequency moves 0.3 Hz to a peak near 50.2 Hz, the upper limit for normal frequency band. In addition, at the time of the increase in wind generation there is an increase is the frequency of dispatch instructions issued by the System Operator.

Event 2 – 23 November 2004

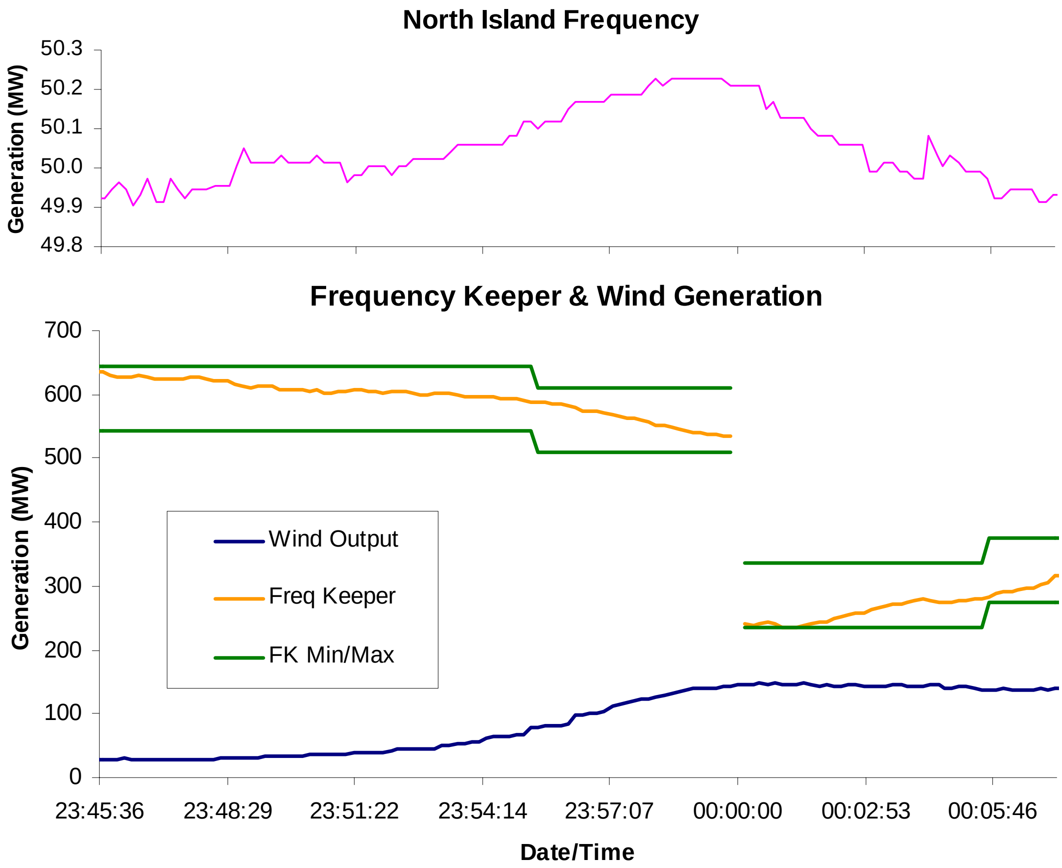

Figure 24 -North Island frequency, frequency keeping generation (and frequency bands) in response to the event on 23 November 2004

For the event starting at 23:50 hours on 23 November 2004, there is a change in frequency keeper at 00:00 on 24 November 2004, hence the discontinuity in the frequency keeping graph (see Figure 24). Again the increase in wind generation is offset by the decrease in the frequency keeper's output and the increase in North Island frequency. During the increase in wind generation the North Island frequency peaks over the normal operating limit of 50.2 Hz for almost three minutes.

Event 3 – 30 December 2004

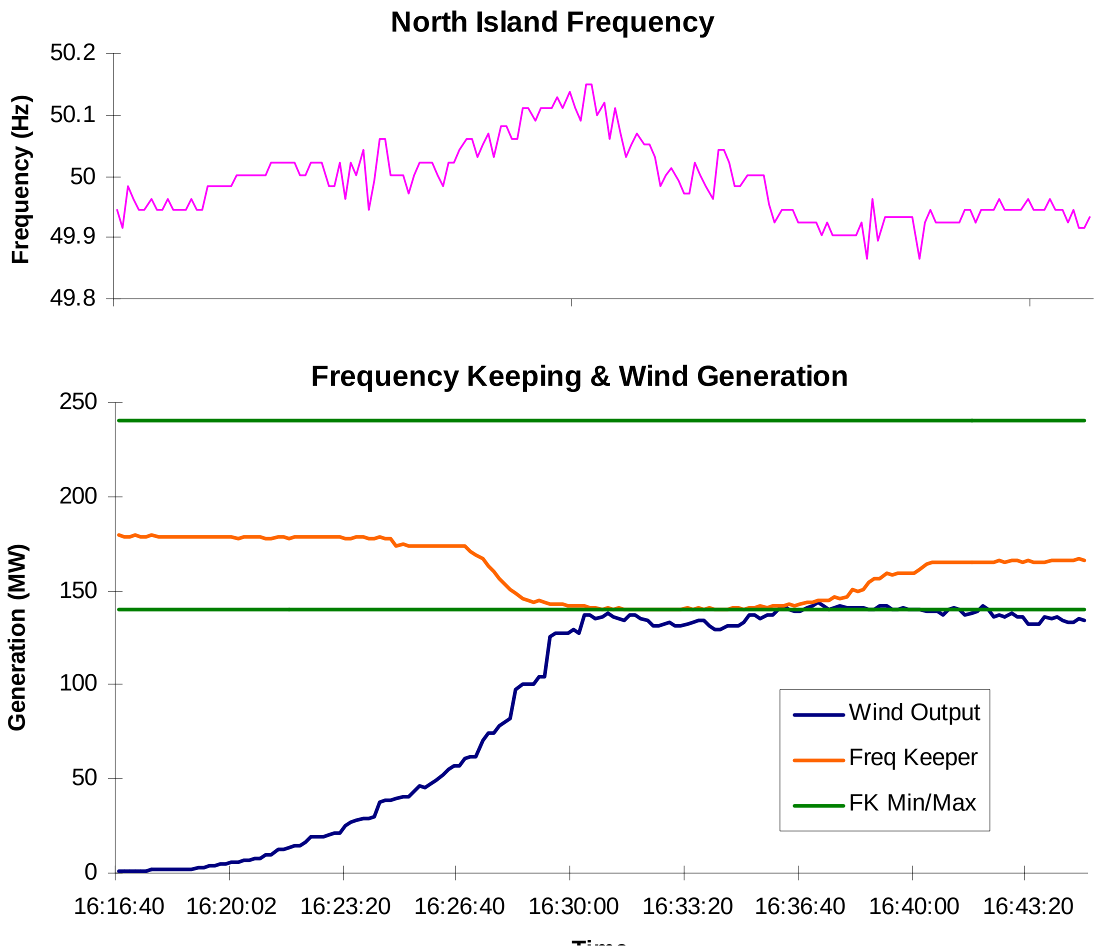

Figure 25 - North Island frequency, frequency keeping generation (and frequency bands) in response to the event on 30 December 2004

The large increase in Manawatu wind generation shown in Figure 25 is offset by the frequency keeper and by an increase in the North Island frequency. The frequency keeper moves down to the bottom of its frequency keeping band, at which point frequency is managed by the System Operator re-dispatching (less) generation to offset the increase in wind farm output. The frequency keeper is then brought back into its band.

Event 4 – 14 February 2005 at 11:30

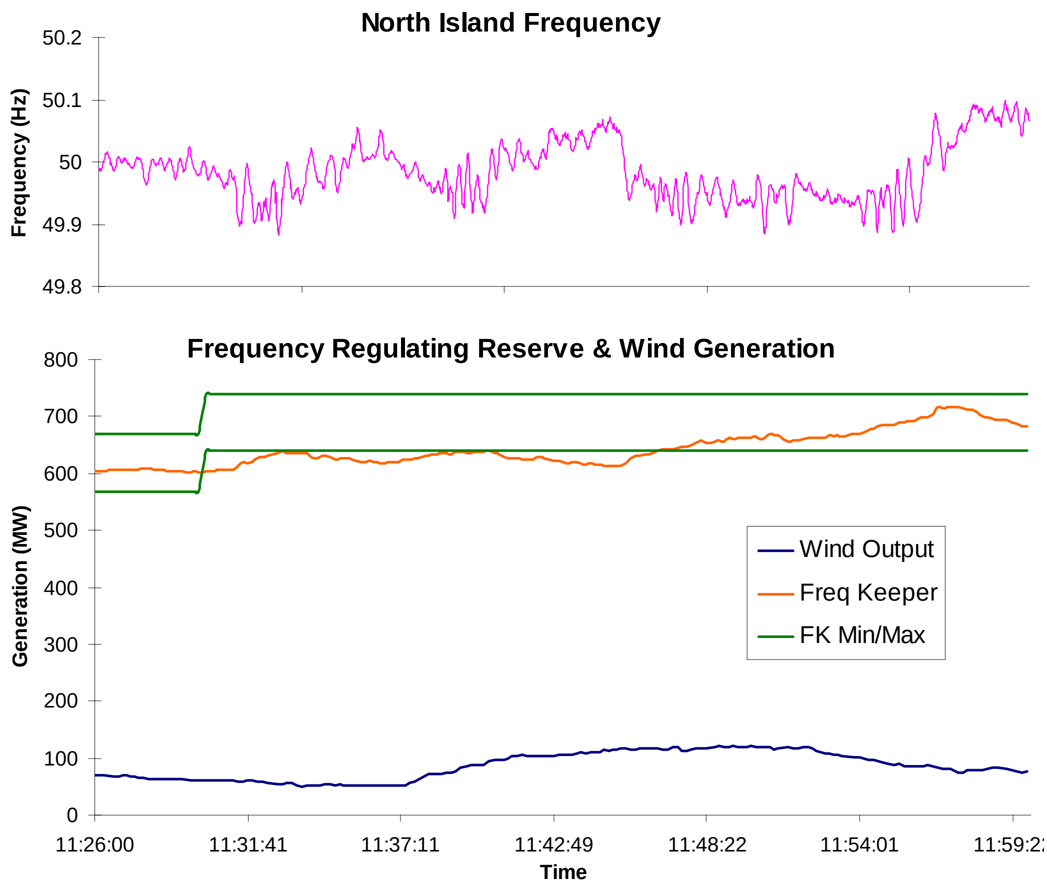

Figure 26- North Island frequency, frequency keeping generation (and frequency bands) in response to the first event on 14 February 2005

The first event on 14 February 2005 where wind generation increase 53 MW in 5 minutes is shown in Figure 25. This change in wind generation appears to be absorbed by the frequency keeper and by other generation, and by a slight increase in the North Island frequency. The frequency keeper's dispatch point has increased at the start of the 11:30 trading period, but in order to maintain the island frequency until the other generators adjust to the new dispatch instruction, the frequency keeper stays below the frequency keeping band.

Event 5 – 14 February 2005 at 14.30 hours

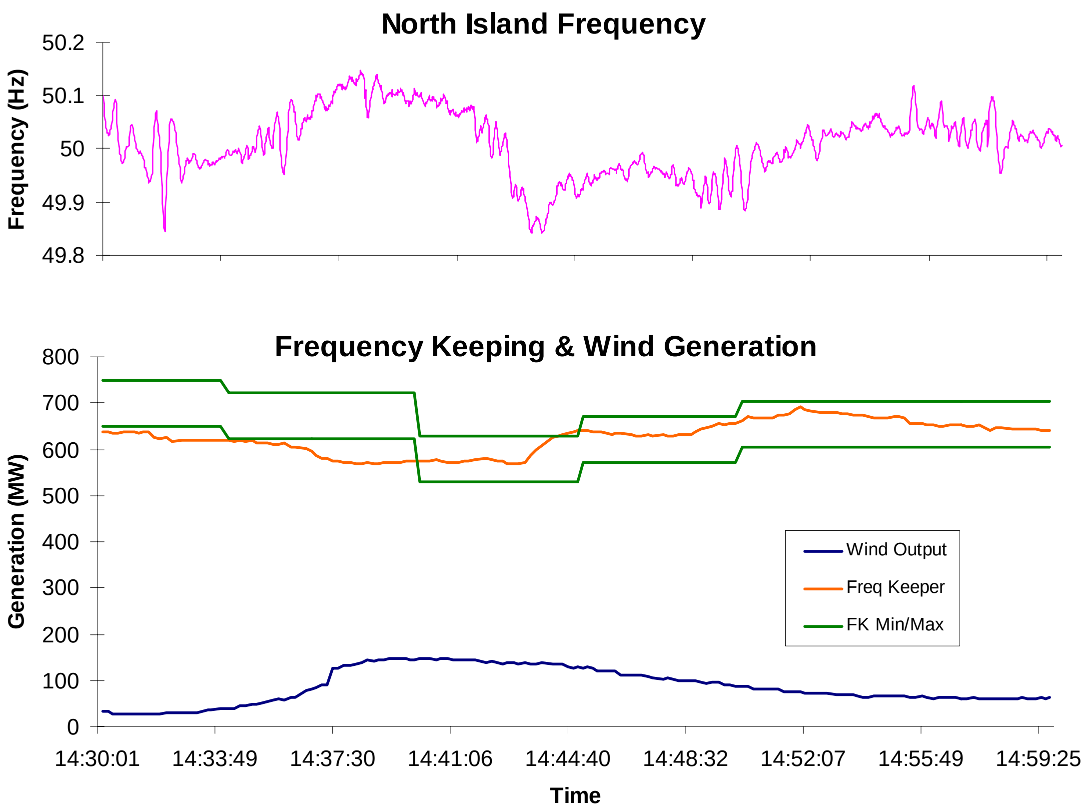

Figure 27 -North Island frequency, frequency keeping generation (and frequency bands) in response to the second event on 14 February 2005

At the start of the wind event on 14 February at 14:30, the frequency keeper is out of its frequency band. It then gets pushed further down as the wind generation and consequent North Island frequency increases (Figure 27). The System Operator is dispatching energy about every 5 minutes over this period. During the increase in wind generation the system frequency stays within normal operating limits.

Event 6 – 25 March 2005

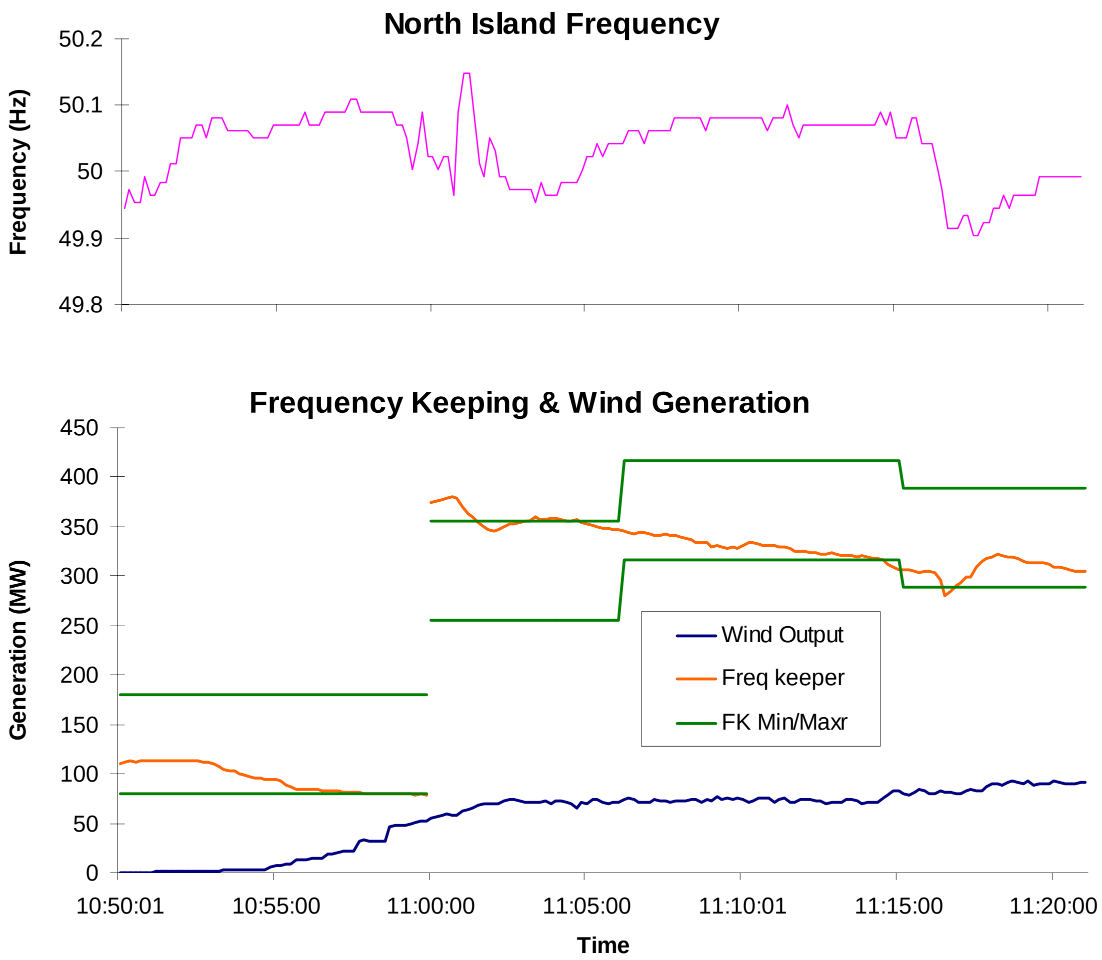

Figure 28 - North Island frequency, frequency keeping generation (and frequency bands) in response to the event on 25 March 2005

The discontinuity observed on the 25 March 2005 for the frequency keeper's generation, and dispatched frequency keeping bands, occurs during the change over of frequency keeper at 11:00 (Figure 28). Again the increase in the wind generation is absorbed by the frequency keeping station, and by dispatched generation. At 11:00, frequency keeper is outside its dispatched band, as it moves towards it new dispatch set point.

Appendix 6 Te Äpiti Generation Forecast Accuracy

Meridian receives a MetService forecast for Te Äpiti at around 09:00 and 15:00 each day. For the period November 2004 to mid January 2005 Meridian used this information to create a day-ahead generation offer from midnight that day to midnight the next day. The Te Äpiti generation offer for the next two hours was generated by a persistence forecast using the 10 minute average from the current trading period. The persistent forecast was updated twice during each trading period. Since mid January 2005, this process has been modified; the MetService forecasts are now used to generate a day-ahead forecast covering the period three hours ahead to midnight the next night. The persistence forecast has been extended and used as the Te Äpiti offer for the next three hours.

The Te Äpiti generation forecast offers for the trading periods 2, 6 and 12 hours ahead have been analysed for the months November 2004 through to March 2005 (see Figure 29 to Figure 31). The graphs show an obvious improvement in the two hour ahead forecast as a result of the extension of the persistent forecasts in January 2005. Table 10 shows how this improvement has resulted in a reduction in the forecast error.

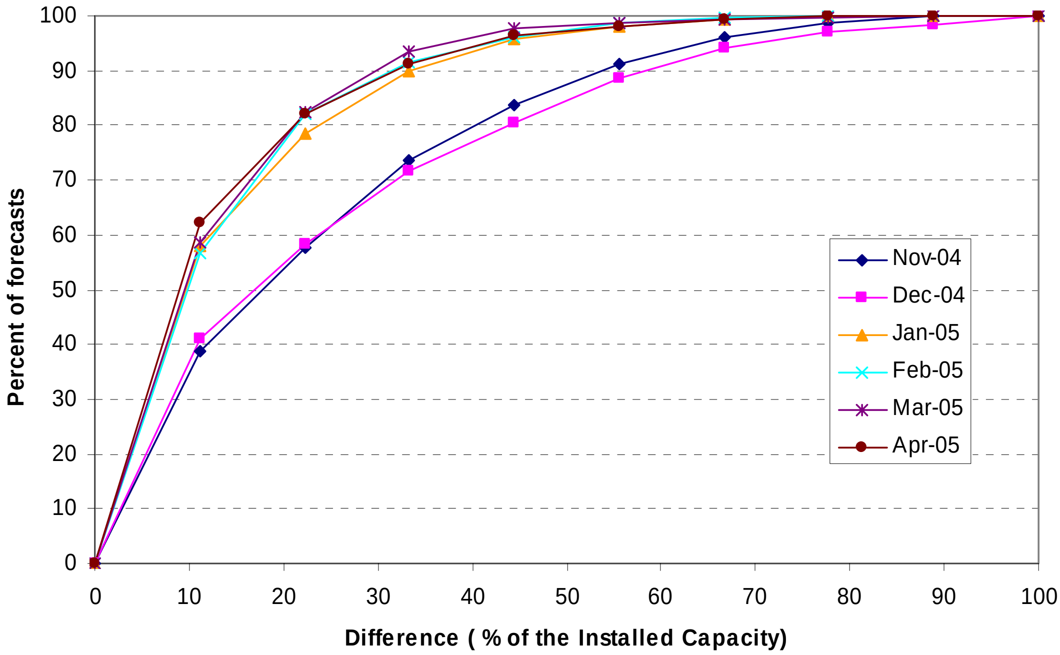

Figure 29 - Cumulative distribution of the Te Äpiti two hour forecast generation error (for months November 2004 to April 2005).

Error (MW)	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	Jan to Apr-05 Summary
0	0	0	0	0	0	0	0
10	39	41	58	57	59	62	59
20	58	58	79	82	82	82	81
30	74	72	90	91	93	91	92
40	84	81	96	96	98	97	96
50	91	89	98	99	99	98	98
60	96	94	99	100	99	99	99
70	99	97	100	100	100	100	100
80	100	98	100	100	100	100	100
90	100	100	100	100	100	100	100

Table 10 – Cumulative distribution of the Te Äpiti two-hour forecast error for November 2004 to April 2005.

In November and December 2004 about 10% of the 2 hour forecasts had an error of greater than 55 % of the installed capacity (50 MW). From January 2005 this has reduced to 2% or less of the 2 hour forecasts.

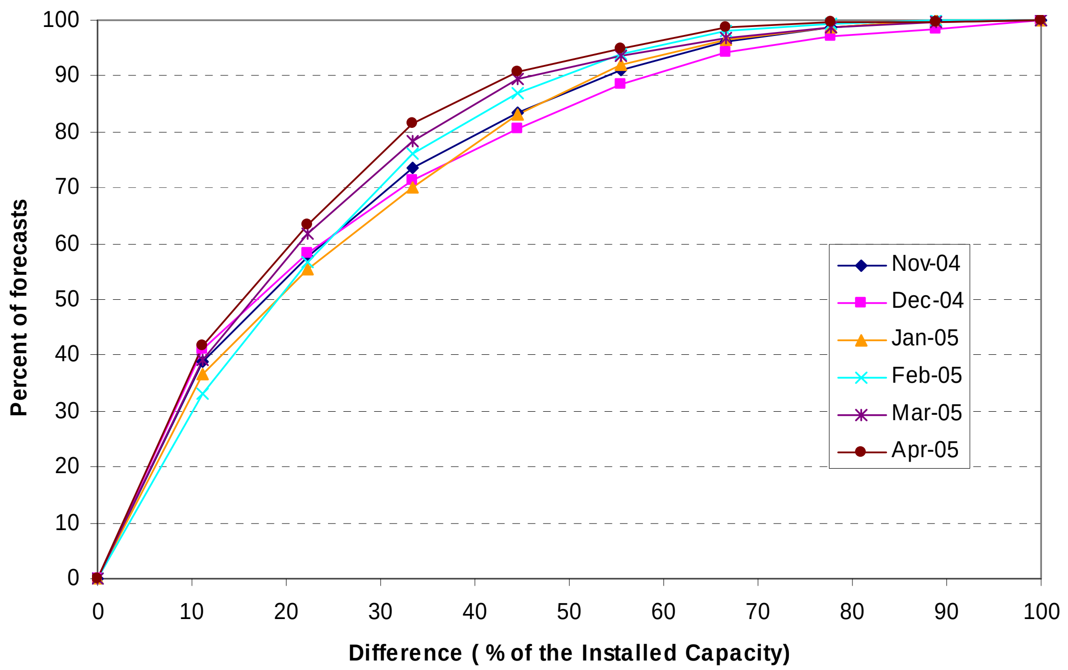

Figure 30- Cumulative distribution of the Te Äpiti six hour forecast generation error (for months November 2004 to April 2005).

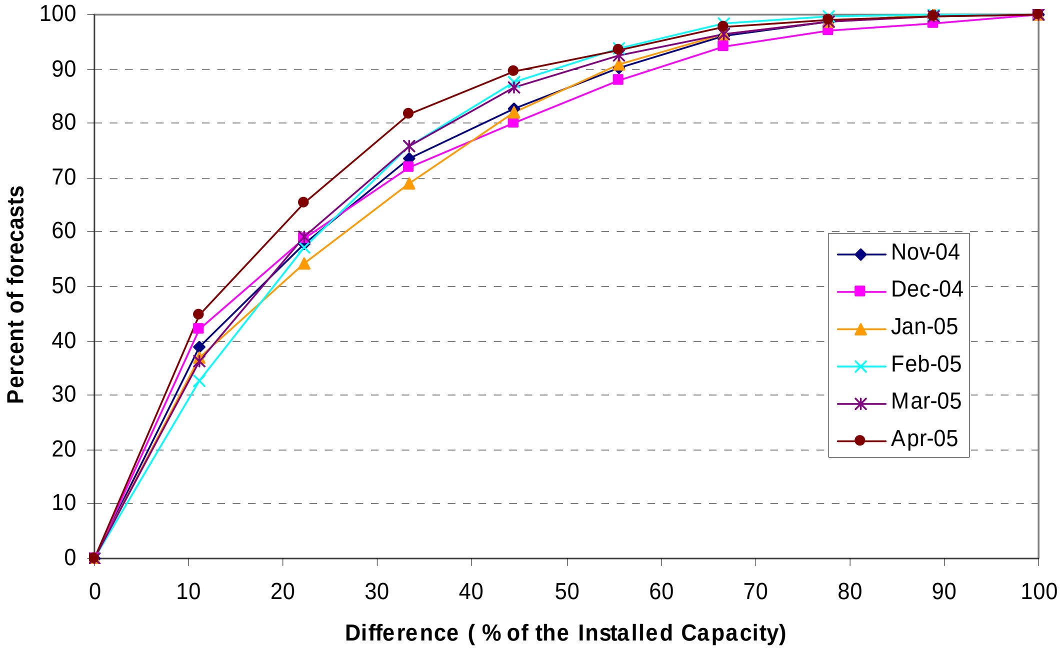

Figure 31 - Cumulative distribution of the Te Äpiti twelve hour forecast generation error (for months November 2004 to April 2005).

As the 6 and 12 hour forecast process remains unchanged, the forecast error remains at about the same level for the entire period analysed; the differences between the months probably reflecting the variability in general weather conditions.

Summary

Figure 32 shows the cumulative distribution of each of the 2, 6 and 12 hour forecasts in the period January to April 2005.

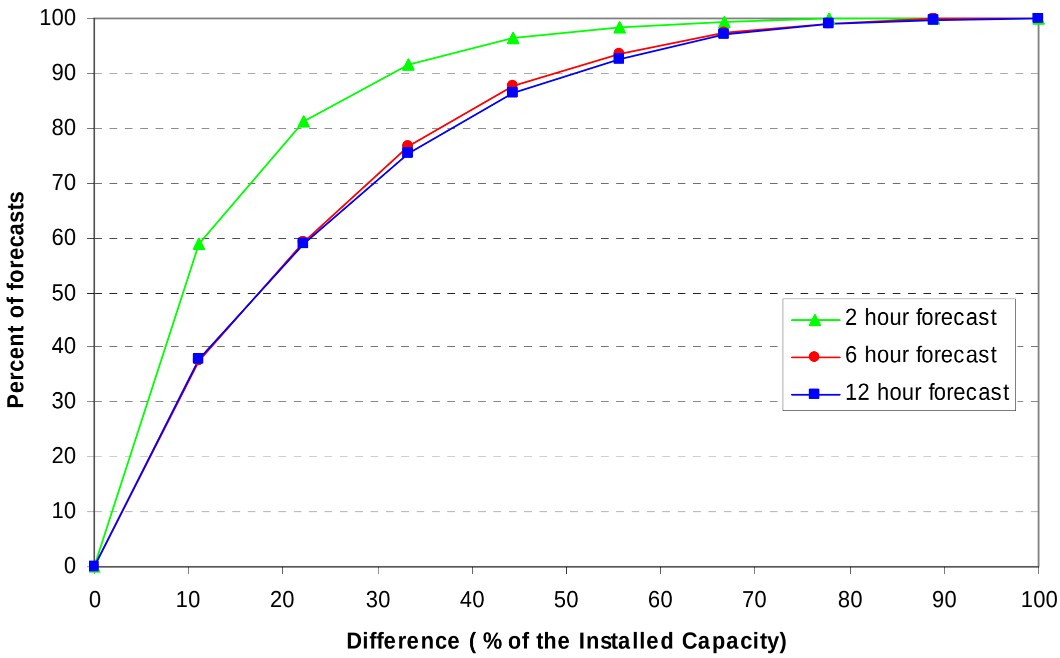

Figure 32 -Cumulative distribution of the Te Äpiti 2, 6 and 12 hour average forecast error for January 2005 to April 2005

This is represented in Table 11.

Error (MW)	2 Hour	6 Hour	12 Hour
0	0	0	0
10	59	38	38
20	81	59	59
30	92	77	76
40	96	88	86
50	98	94	93
60	99	98	97
70	100	99	99
80	100	100	100
90	100	100	100

Table 11 - Percentage of Te Äpiti two, six and twelve hour average forecast with MW errors for January 2005 to April 2005.

For the 2 hour forecasts, 50% of the forecasts had a % difference between the forecast and actual generation of less than 11 % of the installed capacity. For the 6 and 12 hour forecasts, 50% of the forecasts had a difference less than 22 % of the installed capacity. The MW error is greater than 55 % of the installed capacity for 2%, 6% and 7% for the 2, 6 and 12 hour forecasts respectively.

This is an improvement on the forecasts accuracy as previously reported for November and December 2004. For the 6 and 12 hour forecasts the improvement in accuracy may reflect different weather conditions, or an improvement in forecasting Te Äpiti generation.

Appendix 7 Ramp Control Analysis

The influence of a 5, 10 and 20 MW ramp control on the combined Te Äpiti and Tararua wind farm generation for the large Type I events are illustrated in Figure 33 to Figure 36.

<u>Event 1 - 15 November 2004</u>

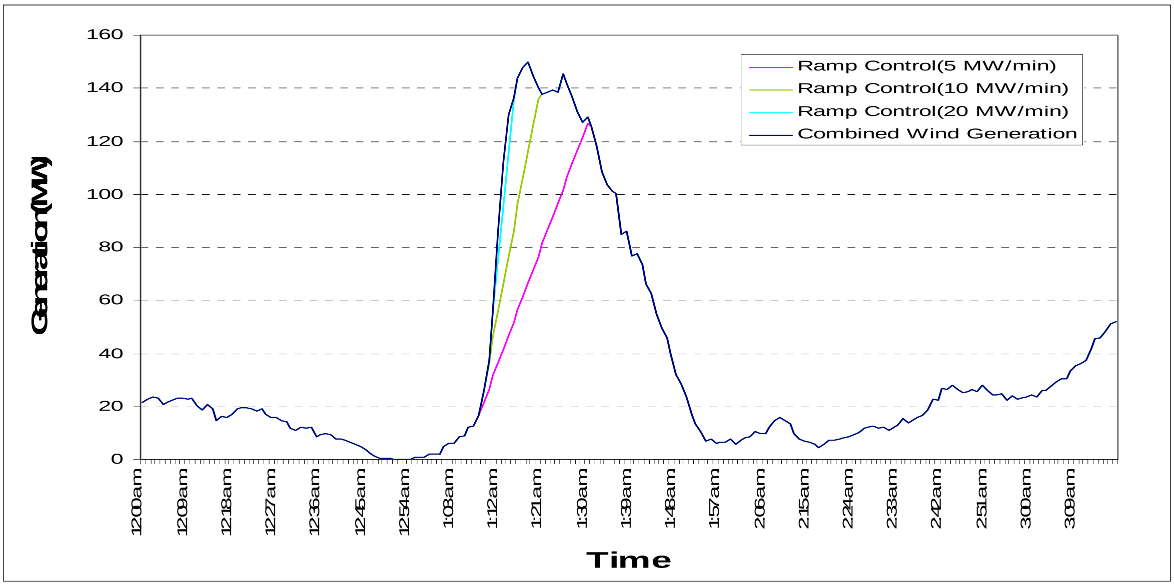

Figure 33 - Combined Te Äpiti and Tararua wind generation illustrated with maximum ramp up restrictions of 5, 10 and 20 MW per minute for 15 November 2004.

<u>Event 2 - 23 November 2004</u>

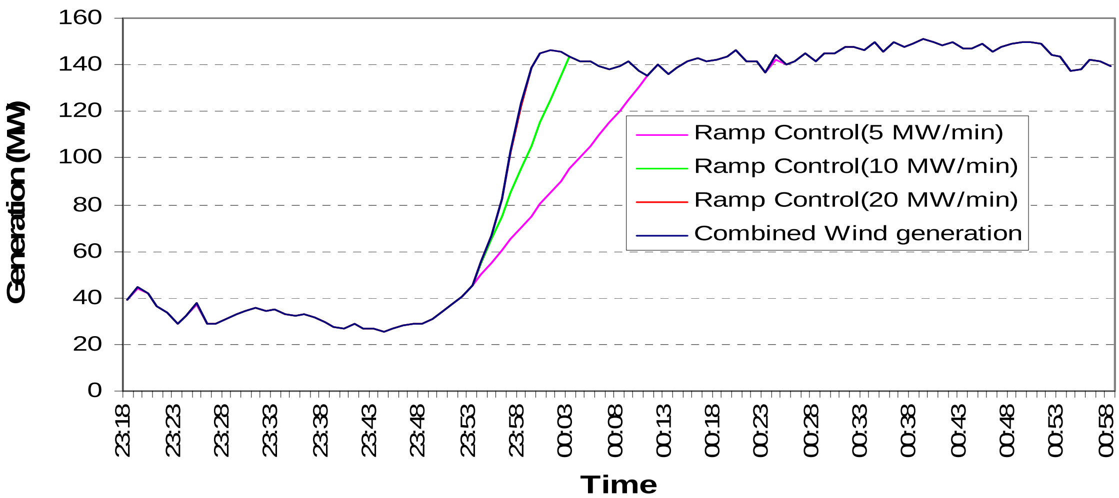

Figure 34 - Combined Te Äpiti and Tararua wind generation illustrated with maximum ramp up restrictions of 5, 10 and 20 MW per minute for 23 November 2004.

Event 3 - 30 December 2004

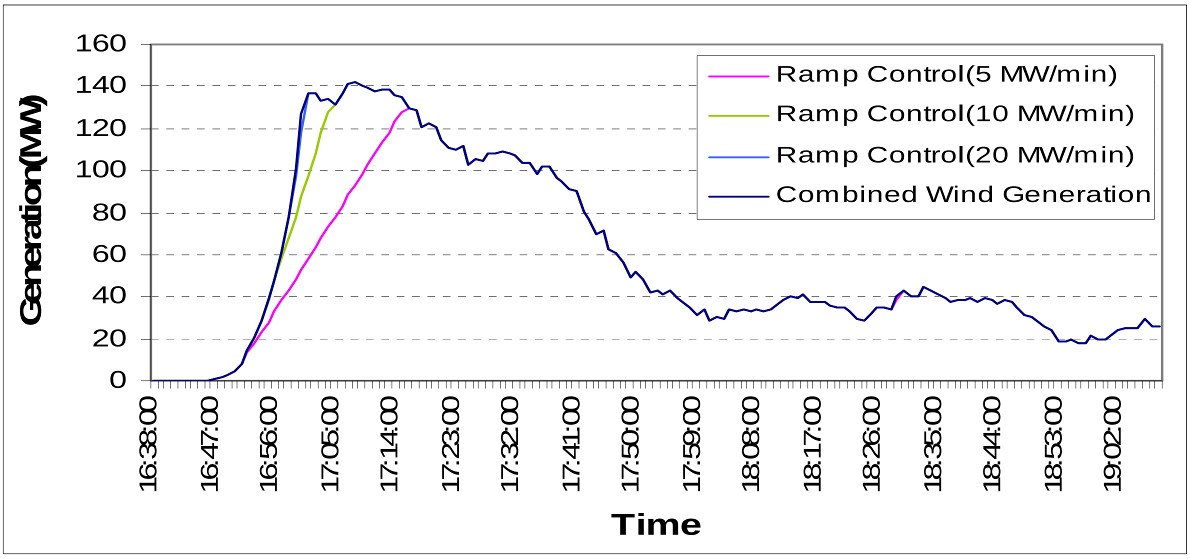

Figure 35 - Combined Te Äpiti and Tararua wind generation illustrated with maximum ramp up restrictions of 5, 10 and 20 MW per minute for 30 December 2004.

Event 5 -14 February 2005 at 14:30

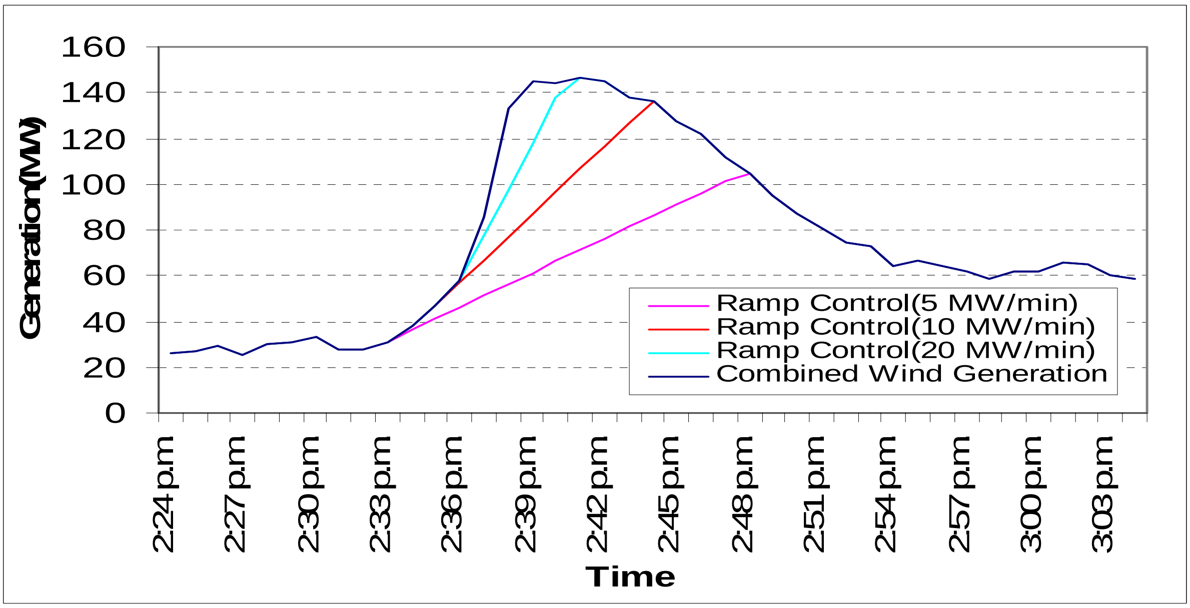

Figure 36 - Combined Te Äpiti and Tararua wind generation illustrated with maximum ramp up restrictions of 5, 10 and 20 MW per minute for 14th February 2005 at 14:30.

Results from this analysis covering six large events are summarised in Table 12.

Date and time of the event	**Duration generation is constrained due to ramp control (in minutes)**			**Energy that would be lost due to ramp control (in MWh)**		
	For 5 MW/min	**For 10 MW/min**	**For 20 MW/min**	**For 5 MW/min**	**For 10 MW/min**	**For 20 MW/min**
15th Nov 2004, 01:00 to 02:00	22	11	11	18	6	0.7
23rd Nov 2004, 11:50 to 12:00	18	9	9	10	3	0.04
30 Dec 2004 16:45 to17:00	24	8	2	15	3	0.2
14th Feb 2005 11:30 to 12:00	13	4	0	4	0.3	0
14th Feb 2005 14:30 to14:45	14	8	4	11	5	1.3
25th March 2005 10:50 to11:05	13	4	0	3	0.3	0
Total loss over the 6 events	104	44	26	61	16.6	2.2

Table 12 - Summary of the ramp rate restriction of 5, 10 and 20 MW per minute on the combined Te Äpiti and Tararua wind generation for the six large events observed between November 2004 and April 2005.

Table 12 shows that for the event on the 23 November 2004, a ramp rate of 5 MW per minute will restrict the Te Äpiti and Tararua generation for 18 minutes with a total loss of 10 MWh. The total energy lost for the observed six events during the November 2004 to April 2005 period, is 61, 16.6, and 2.2 MWh for ramp rate restrictions of 5, 10 and 20 MW per minute respectively.