Castle Hill Wind Farm:
Electricity-Related Effects Report

Prepared for Genesis Energy

July 2011
1 Introduction ........................................................................................................................................... 6
  1.1 Purpose........................................................................................................................................ 6
  1.2 Information sources .................................................................................................................... 6
  1.3 Concept Consulting Group ......................................................................................................... 6
2 The Castle Hill Wind Farm Project .................................................................................................. 7
  2.1 Project Outline ............................................................................................................................. 7
  2.2 Key Electrical Parameters for CHWF ....................................................................................... 7
3 Electricity in the New Zealand Economy ...................................................................................... 8
  3.1 Electricity and Consumer Energy ............................................................................................... 8
  3.2 Electricity consumption and supply in New Zealand ................................................................. 9
  3.3 Historical Electricity Demand ................................................................................................... 10
  3.4 Forecast electricity demand growth ......................................................................................... 11
  3.5 Retirement of existing plant ..................................................................................................... 13
4 Electricity System Overview ........................................................................................................... 15
  4.1 Physical electricity supply system ............................................................................................. 15
  4.2 Real time system coordination ................................................................................................ 16
  4.3 Current electricity generation mix ............................................................................................. 17
  4.4 Hydro and thermal generation .................................................................................................. 17
  4.5 Energy and peak capacity constraints ....................................................................................... 18
  4.6 Electricity Market Arrangements ............................................................................................... 19
  4.7 Price Effects on Power Stations ............................................................................................... 21
5 New Generation Development ....................................................................................................... 23
  5.1 Key forces shaping generation choices .................................................................................... 23
  5.2 Greenhouse gas emissions ........................................................................................................ 23
  5.3 Hydro stations ............................................................................................................................ 25
  5.4 Gas-fired generation .................................................................................................................. 25
  5.5 Coal ............................................................................................................................................ 27
  5.6 Wind generation ........................................................................................................................ 29
  5.7 Geothermal generation .............................................................................................................. 30
  5.8 Non-traditional supply options ................................................................................................. 30
  5.9 New generation costs ............................................................................................................... 31
6 Integrating Wind Farms in the New Zealand System

6.1 Short term flexibility

6.2 Seasonal and year-to-year flexibility

6.3 Integrating Wind Farms into the New Zealand System

6.4 Integrating Castle Hill Wind Farm

7 Potential Benefits of Castle Hill Wind Farm

7.1 Meeting electricity demand growth

7.2 Meeting Government renewable targets

7.3 Reducing carbon emissions

7.4 Diversifying generation supply

7.5 Supply and demand within the region

7.6 Other regional projects

Appendix 1. List of Abbreviations and Terms

Appendix 2. Electricity Market Overview

Appendix 3. CHWF Simulation Analysis

List of Figures:

Figure 1: Total consumer Energy in New Zealand 1990 to 2010

Figure 2: Electricity consumption by sector and by region for 2010

Figure 3: New Zealand economic growth and electricity demand

Figure 4: Change in energy intensity over time

Figure 5: Forecasts of electricity demand

Figure 6: New generation capacity required by 2020 to meet demand growth

Figure 7: Electricity industry structure

Figure 8: Currently electricity generation mix

Figure 9: Commercial arrangements

Figure 10: Prices and load during 3 May 2010

Figure 11: Generation and time weighted prices for various plant (year to March 11)

Figure 12: Economics of new gas-fired generation

Figure 13: Economics of new coal-fired generation

Figure 14: Cost of electricity from new power stations

Figure 15: Generation mix in other jurisdictions

Figure 16: Monthly NZ hydro inflows and generation (Jan 2005 to Feb 2010)
Figure 17: Average wind speed vs NZ hydro inflows 1991/2
Figure 18: Weekly GWh equivalent hydro inflows across the seven main New Zealand hydro schemes
Figure 19: Seasonal patterns in synthetic wind generation output
Figure 20: Correlation between national hydro inflows and wind
Figure 21: Monthly NZ hydro inflows and wind farm supply (Jan 2005 to Feb 2010)
Figure 22: Correlation between CHWF and Tararua Wind Farm
Figure 23: Correlation between CHWF and TeApiti Wind Farm
Figure 24: New renewable generation capacity required by 2025 to meet renewable target
Figure 25: Load and generation in the Central region
Figure 26: Spot market pricing model
Figure 27: Half-hourly spot market prices at Bunnythorpe - week beginning 29 March 2009
Figure 28: Prices and load during 3 May 2010
Figure 29: TAO Model Schematic
Figure 30: North Island Load Duration Curve without CHWF (2016)
Figure 31: North Island Load Duration Curve with CHWF

List of Tables:

Table 1: Castle Hill Wind Farm – Indicative Reference Data
Table 2: Electricity demand growth forecasts (average to 2030)
Table 3: Key Features of the Electricity Market
Table 4: Castle Hill Wind Farm contribution to new capacity requirements by 2020
Table 5: Thermal generation emissions
Table 6: Existing and potential wind farms in the wider Tararua region
Table 7: Key assumptions for CHWF Simulation
Executive Summary

Genesis Energy is seeking the necessary resource consents to construct and operate a wind farm in the Northern Wairarapa, known as the Castle Hill Wind Farm (hereafter referred to as “CHWF”). Although the capacity of CHWF is expected to be of the order of 600 MW, depending on the type and number of turbines eventually selected for the site, a range from 430MW – 860MW is possible. This means that CHWF is a relatively large project, with the potential to supply 3,000 GWh per annum and meet the requirements of up to 370,000 households.

This report explores how CHWF will fit into the current and likely future New Zealand electricity supply system, and considers the national and regional electricity-related effects of the project.

Electricity is vital to the New Zealand economy and, despite trends towards more efficient use, electricity demand is forecast to continue growing, with up to 8,900 GWh per annum of new generation required by 2020. If aging low efficiency power stations are retired, this will further add to the need for new generation projects.

Successive government policies over the last decade have placed an emphasis on the development of renewable sources of generation and this has been shaping generation choices. The application of the Emissions Trading Scheme (ETS) to the electricity sector has reinforced this influence and new generation development is now strongly focussed on geothermal and wind farm development as a consequence. In order to meet a government target of 90% of electricity supply from renewable sources by 2025, a substantial investment in renewable generation will be required.

Hydro-electric generation has played an important role within the New Zealand power system, typically contributing up to 65% of annual supply. Geothermal generation has provided an increasing contribution, reaching 13% in 2010. Wind generation, on the other hand, is relatively new in the New Zealand generation mix and contributed just under 4% of supply in 2010. Although there are opportunities for small-scale hydro developments, the challenges facing large-scale hydro projects suggest that a major new contribution from hydro electricity is unlikely. Substantial new investment in geothermal and wind farm projects will therefore be necessary to meet renewable targets.

Generating electricity from hydro power stations relies on inflows to hydro catchments and, because New Zealand has relatively shallow storage lakes, power supply is vulnerable to extended dry periods. In order to provide a secure supply of electricity, it is necessary to have back-up power stations, typically run on gas, coal or oil, to operate during extended dry periods. There is therefore an important complementary role played by hydro and thermal power stations, which is accommodated by the design of the wholesale electricity market. Generation from wind farms fluctuates with wind speed and can only provide supply on an intermittent basis. As a consequence, wind farms also require back-up from hydro and thermal power stations. As the proportion of wind generation grows, the complementary role of hydro, thermal and wind generation will become an important feature of the system.

Fortunately, the arrangements based around the wholesale spot market provide commercial rewards for different types of generation and these operate to provide incentives for an appropriate mix and operation of generation from these different sources. For example, a feature of the market is that generation from a wind farm typically receives lower average prices than generation from
thermal power stations, or generation from hydro power stations with associated storage lakes. Wind farm developers must take this into account when analysing the economics of a new project.

As part of its review of CHWF, Concept Consulting Group (Concept) has simulated the operation of the wind farm within the New Zealand electricity market. This analysis suggests that the electricity production from CHWF should be readily accommodated within the North Island power system.

This report concludes that CHWF will contribute to meeting the growth in demand for electricity, will contribute to meeting the government target for 90% renewable generation by 2025, will contribute to reducing greenhouse gas emissions, will help to diversify the electricity supply mix, and will support security of supply in the central electricity region.
1 Introduction

1.1 Purpose

Genesis Energy is seeking the necessary resource consents to construct and operate a wind farm in the Northern Wairarapa, known as the Castle Hill Wind Farm (hereafter referred to as “CHWF”). Genesis Energy has commissioned Concept Consulting Group (Concept) to assess the likely effects of the project on the electricity supply system in New Zealand to inform the Assessment of Environmental Effects (AEE) and various resource consent applications for the CHWF.

This report provides a high-level outline of the project, explores how it fits into the current and likely future New Zealand electricity supply system, and considers the national and regional electricity-related effects.

1.2 Information sources

In preparing this report, Concept has relied on a number of documents and related sources for information supplied by Genesis Energy.

1.3 Concept Consulting Group

Concept Consulting Group (Concept) is a New Zealand-based consultancy specialising in energy-related issues. Since establishment in 1999, Concept has advised clients in New Zealand, Australia, Ireland, Singapore and the United States. These clients have included energy businesses, governments, international agencies and regulators.

Concept has undertaken a wide range of assignments, including market development, market analysis, technical evaluations, regulatory and policy analysis, and project management. The firm’s three directors all have extensive backgrounds in executive management positions with energy companies in New Zealand, and the consulting team collectively offers practical hands-on experience across a wide range of disciplines.

The preparation of this report has been overseen by Lee Wilson - a founding director of Concept. Lee is a former chief executive and senior manager with electricity generating and retailing firms in New Zealand, with more than 20 years experience in strategy and planning for those firms.

Since establishing Concept in 1999, Lee has worked extensively on the design and implementation of regulatory and contractual frameworks to support gas and electricity sector reforms and markets. He has a deep understanding of energy markets, project evaluation, regulatory policy and public benefit analysis.
## 2 The Castle Hill Wind Farm Project

### 2.1 Project Outline

The proposed CHWF is located in the Northern Wairarapa and straddles two regional council areas - Greater Wellington and Manawatu-Wanganui (Horizons), and two territorial authority areas - Masterton District and Tararua District. The CHWF site is located 20km east of Ekatahuna and Pahiatua, 20km north-east of Masterton, and 15km west of the Wairarapa Coast north of Castlepoint.

### 2.2 Key Electrical Parameters for CHWF

The generation capacity of CHWF is expected to be of the order of 600 MW. The maximum capacity will be dependent on the type of turbine eventually selected for the site but current site and wind turbine analysis indicates that a range from 430MW – 860MW is possible. The likely range of the key parameters and electricity outputs are outlined in Table 1.

Development of the CHWF may progress in stages, with any first stage likely to be of the order of 300 MW. The capacity depends on the wind turbine model selected, but will also depend on other commercial and technical factors.

### Table 1: Castle Hill Wind Farm – Indicative Reference Data

<table>
<thead>
<tr>
<th>Key Parameter</th>
<th>Likely Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine Capacity</td>
<td>1.5 – 3.3 MW</td>
</tr>
<tr>
<td>Number of Turbines</td>
<td>up to 286</td>
</tr>
<tr>
<td>Total Capacity</td>
<td>430 – 860 MW</td>
</tr>
<tr>
<td>Indicative Annual Output</td>
<td>1,500 – 3,000 GWh</td>
</tr>
</tbody>
</table>

Source: Genesis Energy Limited

Engineering studies suggest CHWF could produce between 1,500 and 3,000 GWh per annum, depending upon the final design, selection of turbine configuration, and the number of turbines.

For the analysis undertaken to inform this report, it has been assumed that CHWF will be configured to supply approximately 600 MW and an average of 2,100 GWh per annum.

It is proposed to connect CHWF to the national grid via a new 70 km double circuit 220kV overhead transmission line running from the CHWF site to connect with the 220kV Transpower Linton to Bunnythorpe line, which feeds electricity into the central North Island region.
3 Electricity in the New Zealand Economy

Electricity is vital to virtually every aspect of modern life, from consumption in the residential setting to a productive input for goods and services. Many of the social and economic benefits enjoyed by New Zealanders stem directly from technologies relying on electricity. In many situations there are no viable alternatives to electricity supply.

This section provides a context for CHWF by describing the demand for electricity within the economy and drawing on a range of forecasts to assess the need for new electricity generating projects over the next 20 years.

3.1 Electricity and Consumer Energy

Electricity is an essential input for modern lifestyles, and for commercial and industrial activity. As illustrated in Figure 1, electricity generally accounts for over a quarter of annual end-use energy consumption in New Zealand, second only to oil (which includes transportation fuels) among sources of delivered energy. Industrial, commercial and domestic activities are all dependent on electricity, including manufacturing, retail, health services, transportation, lighting, water supply and wastewater treatment and disposal. Accordingly, electricity plays a vital role in New Zealand society.

Figure 1: Total consumer Energy in New Zealand 1990 to 2010

Source: MED Energy Data File 2011
3.2 Electricity consumption and supply in New Zealand

Figure 2 shows the breakdown of electricity consumption by sector and by region in New Zealand during 2010.

Figure 2: Electricity consumption by sector and by region for 2010

Source: MED Energy Data File 2011

Residential electricity consumption accounts for approximately 34% of total demand, with commercial (24%) and basic metals (17%) being the other major consumers. The balance of electricity consumption in New Zealand is by primary industries, food processing, wood, pulp and paper processing/printing, and other industrial uses (25%). Almost 66% of electricity demand is based in the North Island, with the regions from Auckland north consuming approximately 28% of the total electricity supplied.

Electricity supply in New Zealand comes from both renewable and non-renewable sources. In 2010, generation classified as renewable accounted for approximately 79% of total generation, and
historically comprised: hydro (56%), geothermal (13%), wind (4%), and co-generation (6%). Non-renewable sources include gas (18%) and coal (3%), which make up the balance of electricity supply\(^1\).

### 3.3 Historical Electricity Demand

Figure 3 explores the historical relationship between electricity demand and economic growth. The chart highlights that electricity demand growth has been closely associated with economic growth, with many of the technologies underpinning economic development relying on electricity supply.

**Figure 3: New Zealand economic growth and electricity demand**

Source: New Zealand Institute of Economic Research, Statistics New Zealand and MED Energy Data File

Over the period since 1974, electricity demand growth has averaged 2.5% per annum. However, the rate of growth has slowed gradually over this period, with the average rate declining to 1.8% per annum over the last 15 years\(^2\).

The gradual decline in the rate of increase of electricity demand has been driven by less intensive use of electricity within the economy and the progressive introduction of more electrically efficient machinery and appliances.

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1. MED Energy Data File; 2011
2. Note that demand fell slightly in 2008 as a result of electricity savings (arising from a public conservation campaign during a period of extreme low hydro inflows) and fell again in 2009 following equipment failure at the Tiwai point aluminium smelter. However demand rebounded relatively strongly during 2010.
This trend is forecast to continue and further reduce the rate of electricity demand growth, relative to economic growth. However, it is considered unlikely that increasing energy efficiency alone will be sufficient to fully offset underlying demand growth.

**Figure 4: Change in energy intensity over time**

![Graph showing energy intensity over time](image)

Source: MED Energy Data File, Statistics NZ, and Treasury forecasts

Figure 4 shows the historic relationship between GDP and electricity demand, expressed as an electricity intensity ratio (electricity consumption per $ of GDP). A fall in electricity intensity indicates that the economy is becoming more efficient in generating domestic product and is consuming less electricity for each $ output of domestic production.

Figure 4 demonstrates that the economy became more electricity intensive through the 1970s and 1980s during a period in which New Zealand invested in electricity intensive projects. Since a peak in 1993, electricity intensity has been steadily declining and it is forecast to decline further over the next 15 years. Note that, despite this projected fall in intensity, overall electricity demand is still forecast to grow.

### 3.4 Forecast electricity demand growth

Longer term factors which could cause electricity demand growth rates to fall include the possibility of higher electricity prices, arising from higher generation development costs and the impact of the
Emissions Trading Scheme (ETS), and the increased uptake of energy efficiency initiatives (in response to higher electricity prices and/or possible policy interventions).

There are also factors that could counter expectations of slowing demand growth, including the possibility of higher population growth and the possible uptake of electric powered vehicles. Nevertheless, there appears to be a reasonable consensus that over the longer term the rate of demand growth will be below levels previously observed. For example, reference forecasts published by the Electricity Commission\(^3\) and the Ministry of Economic Development (MED)\(^4\) indicate average annual growth rates to 2030 of between 0.7% and 2.0%\(^5\). These forecasts acknowledge a level of uncertainty by incorporating sensitivities and alternative scenarios as outlined in Table 2.

**Table 2: Electricity demand growth forecasts (average to 2030)**

<table>
<thead>
<tr>
<th>Organisation</th>
<th>Scenario</th>
<th>Growth rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity Commission</td>
<td>Baseline</td>
<td>1.7% pa</td>
</tr>
<tr>
<td></td>
<td>Upper 80% confidence interval</td>
<td>2.0% pa</td>
</tr>
<tr>
<td></td>
<td>Lower 80% confidence interval</td>
<td>1.3% pa</td>
</tr>
<tr>
<td>Ministry of Economic Development</td>
<td>Baseline</td>
<td>1.3% pa</td>
</tr>
<tr>
<td></td>
<td>Very high growth</td>
<td>1.8% pa</td>
</tr>
<tr>
<td></td>
<td>High growth</td>
<td>1.6% pa</td>
</tr>
<tr>
<td></td>
<td>Low growth</td>
<td>1.0% pa</td>
</tr>
<tr>
<td></td>
<td>Very low growth</td>
<td>0.7% pa</td>
</tr>
</tbody>
</table>

*Source: Electricity Commission and MED data*

While there is some variation across the forecasts, it is generally accepted that demand for electricity in New Zealand will grow at rates most likely to be between 1.0% and 1.7% per annum, over the next twenty years. New Zealand will need to generate between 400 and 700 GWh additional electricity each year to accommodate electricity demand growth in this range.

Figure 5 illustrates the impact of the demand projections listed in Table 2.

The figure illustrates the considerable uncertainty about future levels of demand, culminating in a 13,000 GWh per annum difference between the highest and lowest forecasts by 2030. Focusing on the nearer term, annual electricity demand is expected to grow between 3,800 GWh and 8,900 GWh by 2020.

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3  http://www.electricitycommission.govt.nz/consultation/09-demand
4  “New Zealand’s Energy Outlook - 2009 Edition”, Ministry of Economic Development. Average growth rates to 2030 have been derived from generation forecasts (demand plus losses).
5  Derived from growth rates for each year from 2011 to 2030, for each forecast scenario.
3.5 Retirement of existing plant

In addition to meeting future demand growth, new generation may be required to replace some older, less cost-efficient power stations as they are retired. Although some power stations may be refurbished as they age it is considered likely that older low efficiency thermal power stations will eventually be replaced with new, more efficient, and cleaner generating technology. The level and timing of retirements is uncertain, but will be strongly influenced by the policy environment.

Of particular interest is the original 25 year old 6 1,000 MW conventional coal/gas fired station located at Huntly. New generation that is added to the power system is typically very low fuel cost, or more efficient that the old Huntly units 1-4. This means that new power stations tend to displace Huntly units 1-4 and they only tend to run during periods of very high demand, when other power stations break down, or during extended dry periods in hydro catchments. Genesis Energy has achieved commercial arrangements that have allowed full availability to date, but continues to actively review the viability of Huntly units 1-4. As part of this review, Genesis Energy has considered a range of options including outright retirement of some units, long-term storage of units, and short-term storage of units.

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6 The last of the four original 250 MW generating units was commissioned in 1985 but the station was built between 1973 and 1985 so some components are significantly older than 25 years.
The most recent expectation\footnote{Genesis Energy Statement of Corporate Intent, June 2010} is that at least three units will remain in service through 2014, and that the other unit will be available on a three-month recall basis. If commercial arrangements can be secured, it would be possible to extend these timeframes.

The retirement of older power stations could add substantially to the need for new generation in the next 10-20 years. Figure 6 illustrates the new generation capacity that would be required by 2020 (for example) in order to meet electricity demand growth and to replace the whole or part of the contribution from the 1,000 MW Huntly conventional coal/gas fired power station.

**Figure 6: New generation capacity required by 2020 to meet demand growth**

CHWF will be a large wind farm in comparison with others in New Zealand and its annual energy contribution is expected to be between 1,500 and 3,000 GWh per annum. Figure 6 also highlights the contribution that CHWF could make towards meeting the demand for new generation by 2020.

This section has described the important role of electricity within the economy, how the demand for electricity has been growing and is forecast to continue growing, and what this means for the need for new generation projects.

It also explores the possibility that new generation will be required to not only meet the growth in demand, but also to replace aging thermal power station units.

CHWF, potentially supplying up to 3000 GWh per annum, is placed within this context.
4 Electricity System Overview

This section provides background information to the CHWF project by describing the electricity supply system in New Zealand, how the supply and demand for electricity is coordinated, the current mix of electricity generation and its dependence on hydro electricity supply, and the key features of the electricity market. It also illustrates how these arrangements combine to provide electricity revenues for different generation plant types. This information is provided because it is important background to understanding the contribution CHWF will make to the electricity supply system.

4.1 Physical electricity supply system

The physical electricity supply system in New Zealand is shown schematically in Figure 7, which includes electricity demand figures for the year ended March 2010.

Figure 7: Electricity industry structure

Source: Concept Consulting Group and MED 2010 Energy Data File
This figure highlights that:

- The vast majority of generation (92%) is supplied through the transmission network, although some generation is embedded, either in a local distribution networks (5%) or onsite at a large industrial user (2%);

- Local network companies distribute 69% of electricity generated to residential, commercial and industrial users, while 21% is consumed by large industrial users directly from the transmission network; and

- 7% of energy is lost as heat in the transmission and distribution process.

4.2 Real time system coordination

The physical characteristics of electricity mean that demand and supply must be matched on a continuous basis. A mismatch of generation and load causes the power system frequency to slow or speed up. Frequency must be maintained within the limits of the engineering tolerances of the generating plant on the power system or it can cause the progressive loss of generating stations (resulting in a cascade failure) and power black outs.

In order to keep load and generation in balance, the output from particular generators (such as hydro power stations with storage lakes, and thermal generation with flexible fuel supply) is raised or lowered to adjust for changes in demand and for fluctuations in generation from sources that vary as a result unpredictable factors (for example run-of-river hydro or wind generation).

In real time, this coordination of supply and demand is undertaken by Transpower in its capacity as the System Operator, as it monitors demand and other power system conditions, and makes decisions about the level of generation plant to call into service. This coordination process is part of what is known as the dispatch process.

In order to cover contingencies (such as the sudden outage of a transmission line or a power station unit) the System Operator also maintains reserve capacity that can be called instantly into service. This takes the form of power stations with particular characteristics that allow fast-acting pick up of load, and customer loads that can be quickly shed in an emergency.

The requirement to continuously match supply and demand means that generators make their power stations available to be coordinated by the System Operator in real time. This poses particular challenges for operating a competitive market in electricity. How these challenges are overcome in the New Zealand context are outlined in subsequent sections.
4.3 Current electricity generation mix

New Zealand’s electricity is supplied from a variety of sources, as illustrated in Figure 8.

Figure 8: Currently electricity generation mix

![Chart showing electricity generation mix from 2000 to 2010](image)

Source: MED Energy Data File and Electricity Authority Centralised Data Set

This chart shows that hydro generation continues to dominate supply, accounting for over half of New Zealand’s electricity needs (a range of 52-65% in the years shown). Thermal generation is the next most significant source of electricity and ranges from 27-37% of total generation in the years shown. Geothermal sources have increased their relatively small share of generation from 7% in 2000 to 13% in 2010). Cogeneration (generating electricity from the waste heat from industrial processes) holds a steady share of electricity production (6-8%). Wind generation has increased significantly over the period to just under 4% in 2010, but remains a very small component of supply.

Overall it is worth noting that the renewable component of supply has fluctuated with movements in hydrology, but has averaged 75% over the period from 2000 to 2010.

4.4 Hydro and thermal generation

A feature of the New Zealand electricity system, and how it is operated, is the complementary role between hydro and thermal generation. Hydro generation can vary greatly from year to year because the supply is vulnerable to periods of low rainfall and low inflows into the hydro lakes.
During low inflow periods, output from thermal generation increases to offset the reduced output from hydro generators.

However, the relative contribution of thermal generation has been declining while the contribution of wind and geothermal sources has been growing. Figure 8 shows that between 2005 and 2010 the share of generation from:

- Hydro sources was very similar (56% in both 2005 and 2010);
- Wind and geothermal renewable sources increased (from 9% in 2005 to 17% in 2010),
- Thermal generation reduced (from 28% in 2005 to 21% in 2010).

This means that the proportion of supply from power stations with flexible fuel supply (which are able to respond to fluctuations in demand and supply as described in section 4.2) is declining relative to the proportion of supply from power stations that provide intermittent production or are designed to operate continuously.

### 4.5 Energy and peak capacity constraints

New Zealand’s high dependence on uncertain hydro supply means that total power station capacity (the maximum ability to generate electricity) is significantly greater than actual peak supply requirements. This is because the country needs extra thermal power station capacity to cover droughts and hydro schemes are typically designed with capacity to cope with high inflow periods. The New Zealand electricity supply system has therefore generally been considered to be ‘energy constrained’ rather than ‘capacity constrained’. Security of supply risks\(^8\) in New Zealand have therefore tended to be seasonal, and at their highest in winter (when electricity demand is at its highest and when hydro inflows are at their lowest).

The energy constrained system in New Zealand contrasts with most other countries where thermal capacity dominates supply. In these countries security of supply risks are generally highest at peak demand times, and the systems are often described as being ‘capacity constrained’\(^9\).

Over time, it is possible that the New Zealand system will become more like those in most other countries, especially as the supply mix changes and an increasing proportion of demand is met from power stations that provide intermittent production or are designed to operate continuously.

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\(^8\) The likelihood of electricity shortages or supply restrictions.

\(^9\) For example, in Victoria in Australia, it is not uncommon for supply to be very tight on an unexpectedly hot day due to air conditioning loads. Thermal power stations need to be started up well in advance of being needed, requiring more than a day if they have been shut down for a while. Unexpected hot weather can therefore cause supply restrictions.
4.6 Electricity Market Arrangements

The commercial arrangements in the electricity sector are underpinned by a spot market. This is highlighted by Figure 9 which provides a schematic representation of the physical supply and commercial arrangements within the electricity market.

Figure 9: Commercial arrangements

Generators | Transpower | Distributors | Customers
---|---|---|---

Wholesale Market | Retail Market

Bilateral Contracts | Spot Market | Retailers*

*Note that some consumers also buy from the wholesale market.

This figure highlights the distinction between the wholesale market and the retail market:

- **The wholesale market** operates on the national transmission grid with generators supplying electricity into the transmission system at grid injection points and retailers purchasing electricity at grid exit points. A spot electricity market is used to coordinate supply and determine the wholesale price for electricity.

- **The retail market** operates on the distribution networks with retailers purchasing distribution services, and selling delivered electricity direct to consumers.

Retailers and generators also enter into bilateral contracts linked to the spot market. Note that some large consumers choose to purchase electricity directly from the wholesale electricity market.

The features of the commercial electricity market arrangements are described in more detail in Appendix 2 and some key features are summarised in Table 3.
Table 3: Key Features of the Electricity Market

<table>
<thead>
<tr>
<th>Description</th>
<th>Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spot Market</td>
<td>The wholesale market is centred on a spot market where generators compete to supply electricity on a half hourly basis.</td>
</tr>
<tr>
<td>Spot Prices</td>
<td>The spot market produces half-hourly spot prices which fluctuate according to demand, supply and transmission conditions. This means that spot prices are typically higher at times of peak demand in the mornings and evenings and higher when supply is short, such as during an extended period of low inflows to hydro catchments.</td>
</tr>
<tr>
<td>Location Specific Pricing</td>
<td>Spot market prices are determined for each half hour and for over 200 locations across the national grid. The spot price varies from location to location depending upon the pattern of transmission losses and constraints across the grid such that the typical pattern is for prices in the North island to be higher than the South Island and for prices to be higher in the north of each island than the south of each island.</td>
</tr>
</tbody>
</table>

The combined effect of these arrangements is that electricity spot prices vary significantly across time and by location as illustrated in Figure 10, which is repeated from Appendix 2.

Figure 10: Prices and load during 3 May 2010

Source: Electricity Authority (Central Data Set)
The figure illustrates that:

- As demand varies throughout the day, with morning and evening peaks, spot prices tend to follow a similar pattern; and

- Prices in the north tend to be relatively higher than those in the south;

- In this example, prices at Bunnythorpe are close to prices at Haywards.

The pattern of prices rising up through the North Island is typical, and reflects the normal balance of generation and demand across the country, with surplus generation from the South Island flowing north to supply higher demand and flowing up through the North Island from Wellington to Northland.

### 4.7 Price Effects on Power Stations

As illustrated by Figure 27 in appendix 2, spot market prices can vary significantly with the level of electricity demand and the availability and cost of generation. This means that generators that are able to schedule production when prices are higher will receive a higher average price for their production than generators that are inflexible or can only generate intermittently.

For example, thermal power stations with a flexible fuel supply, and hydro power stations with storage, have the capability to increase or decrease production during the day, and from day to day, generating more when the spot price is high and less when the spot price is low. The average price that power stations with a flexible fuel supply receive per unit of production therefore tends to be higher than the simple spot price average. In contrast, geothermal power stations tend to operate continuously at full output levels and the average price they receive per unit of production is close to the simple spot price average. Wind farms are obviously dependent on a level of wind to generate, and can therefore only produce on an intermittent basis. If high wind levels coincide with periods of high price that is fortuitous, but coincidental.

Figure 11 compares the generation-weighted price (i.e. the average price that would be received for electricity generated) and the time-weighted price (i.e. the simple average spot price) for a number of power stations in New Zealand for the year to September 2009.

This figure highlights that, during the year ending March 2011:

- Generation at Waikato and Huntly was able to earn more than the time-weighted price (39% more in the case of Huntly) because these power stations were able to be scheduled to run when prices were relatively high;

- Geothermal generation from Wairakei received very close to the simple time-weighted price because geothermal generation is designed to run continuously at full output; and

- Wind generation from Te Apiti and Tararua wind farms received less than the time-weighted average (13% less in the case of Tararua), because their production levels tended to be poorly correlated with periods when prices were high. Indeed, a surplus of wind will tend to depress prices as the overall level of generation supply increases, whereas a lack of wind will tend to increase prices as the overall level of generation supply decreases.
This feature of the electricity market arrangements ensures that all generators face price signals that encourage efficient outcomes. For instance, generating plant that is ‘firm’ at times of scarcity will capture the higher market prices associated with such scarcity and thus earn a generation-weighted average price that is at a premium to the time-weighted average price. On the other hand, generating plant that is not ‘firm’ at times of scarcity will suffer a generation-weighted average price that is at a discount to the time-weighted average price.

All generation investors must take these relative effects into account when evaluating potential developments and projecting the likely revenue stream available from a new project. Genesis Energy, in particular, will need to take into account that CHWF will tend to earn revenue at less than the time-weighted average spot price in the wholesale market.

This section has highlighted the mix of generation sources within the New Zealand power supply system, the important complementary role played by hydro and thermal power stations, and the energy constrained nature of the supply system.

It has also described the commercial arrangements based around the wholesale spot market and how these market arrangements provide commercial rewards for different types of generation.

In particular, this section has identified that wind farm developers must take into account the intermittent nature of supply and the implications this has for likely revenues from the wholesale market.
5 New Generation Development

This section explores the options for new generation development in New Zealand and identifies the most likely sources of new development through the next 20 years. In particular, it highlights the potentially important role for new wind farms, such as CHWF, in the future supply mix.

5.1 Key forces shaping generation choices

Section 4 highlighted the current mix of generation plant and the strong influence of hydro and thermal power stations in New Zealand. Looking forward, a number of forces are acting to influence choices among future generation options for New Zealand. These include:

- Following government led reforms initiated in the early 1990s, New Zealand taxpayers and successive governments have been unwilling to provide extensive subsidies for large-scale generation projects;10

- The outlook for gas supply has deteriorated significantly, especially since gas production from the Maui gas field has declined;

- The technical performance of all generation types has improved, but has been more marked for some technologies. In particular, over the last 10-15 years there have been major advances in gas-fired turbines and wind turbines, with sizeable efficiency, reliability and cost improvements being achieved;

- New Zealand has signed the United Nations Framework Convention on Climate Change (often referred to as the ‘Kyoto Protocol’) on greenhouse gas emissions, committing it to reducing greenhouse gas emission levels. As discussed in the next section, this is expected to have a major influence on decisions in the power sector.

5.2 Greenhouse gas emissions

Under the Kyoto Protocol, New Zealand has agreed to limit its greenhouse gas emissions during the period 2008-2012 to the level in 1990. To the extent that actual emissions exceed the 1990 level, New Zealand has an obligation to cover the deficit by purchasing credits on the international market. Similarly, if New Zealand has a surplus, it can sell the excess emission entitlements. Because the emissions limit is binding in aggregate on Kyoto Protocol signatories, trading of entitlements effectively establishes an international price for emission rights – which can be expressed in terms of $ per tonne of carbon dioxide equivalent ($/t $CO_{2}$). Measures to reduce emissions in New Zealand can be valued against this benchmark.

The Government is seeking to reflect the Kyoto Protocol obligations into the electricity generation sector. The previous Government established the ETS, under which electricity generators would...

10 Relative to the regime applying in the 1950-80s, modern enterprises, including those that are state-owned, are subject to much greater financial discipline and transparency.
have been required to pay for greenhouse gas emissions at international carbon prices, from 1 January 2010.

The current Government has implemented the Climate Change Response (Moderated Emissions Trading) Amendment Act to revise the ETS. Nevertheless, the ETS remains the primary mechanism through which climate change policy will be promoted and it came into effect for certain sectors, including energy, in July 2010. The current Government has also reinforced a strong preference for renewable generation, including a target of 90% of electricity supply generated from renewable sources by 202511.

The ETS will increase the operating costs of thermal power stations (and to a lesser extent geothermal power stations) with flow on effects to electricity prices. Higher electricity prices will make renewable generation development options more commercially attractive, although individual generation projects will still need to compete on their own merits according to local market prices, capital and operating costs, including fuel, system and, carbon costs.

The revised ETS12 retains a “cap and trade” system but includes a transition phase to 31 December 2012 during which:

- Participants are required to surrender only one emission unit for every two tonnes of CO₂e emitted; and
- Participants may elect to pay a fixed price of $25 per emission unit.

These changes have softened the introduction of the ETS on participants. In particular, the effective price of emissions for electricity generators is $12.50 per tonne of CO₂e emitted during the transition period.

Beyond the transition period it is expected that electricity generators will need to purchase emission units at their full price, reflecting the price at which units trade in international markets. The Government compiles estimates of the price of Kyoto compliant emission units. These estimates rose steadily over the period 2005 to 2008 to peak above NZ$25/t CO₂e. The global financial crisis has seen values fall, with the most recent estimate13 NZ$19/t CO₂e.

Forecasts of future carbon costs tend to focus on the likely cost of carbon abatement measures14 and suggest that, all other things being equal, carbon values are likely to increase in the period beyond 2012, at least until major technological advances occur.

14 See, for example, Global Cost Curve for Greenhouse Gas Abatement Measures; Mickinsey & Company, 2007. This study sought to estimate the 'supply' curve for carbon abatement in 2030. The study identified a range of options such as relatively cheap energy efficiency improvements through to increasingly costly carbon abatement options. The results of the study suggest that marginal abatement costs in 2030 could fall in the range €25-50/tonne CO₂e (approximately NZ$45-90/tonne CO₂e) and the suggestion is that these marginal abatement costs will tend to drive the value of emission units by 2030.
The expected cost to power station operators of purchasing NZ Emission Units is expected to have a significant impact on the cost of electricity, and the relative economics of different generation options, particularly if carbon values rise beyond 2012.

5.3 Hydro stations

The last large scale hydro development in New Zealand took place in the 1980s at Clyde, and encountered strong community opposition at the local and national levels. More recently, Meridian Energy pursued a canal-based hydro development in the Waitaki basin (Project Aqua). It had originally indicated that the cost of this development would have been of the order of $1.2 billion and would have produced around 3,000 GWh in an average year. This project also encountered strong opposition, especially at the local level. Meridian Energy ultimately abandoned the project, citing rising cost estimates as the principal reason.

It is also important to recall that most of the hydro stations built in the past were directly sponsored by central government. As a result, some developments were able to proceed despite poor economic prospects. It is considered unlikely that such outcomes will be tolerated in the current market environment.

Several large scale hydro development opportunities exist in the South Island. Examples include the Beaumont, Tuapeka, Luggate and Queensberry sites on the Clutha River, which were the subject of preliminary scoping and consultation. Consents have been granted for projects on the Arnold, Rakaia, Ngakawau, Wairau, and lower Waitaki rivers, which in total could provide more than 400 MW of new capacity. Consent has also been granted for an 85 MW project on the Mokihinui river, but is subject to appeal.

There are hydro projects under investigation in the North Island, but no tangible prospects offering supply in the medium term have emerged.

A combination of technical issues, project economics and public opposition, suggest that large scale hydro developments will continue to be challenging. Further, there are conservation orders on some of the rivers with potential large-scale hydro development sites.

There are undoubtedly opportunities for a number of smaller scale hydro developments and many are under investigation by a wide range of parties. Project economics and resource consenting issues are likely to provide significant challenges to overcome.

5.4 Gas-fired generation

Over the last 15 years larger scale electricity generation developments in New Zealand have typically been gas fired. However, future gas supplies are uncertain with the Maui gas field running down quickly and new commercial gas discoveries offering more modest contributions.

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15 Considered to be larger than 30 MW.
16 Commissioning was delayed, and took place in 1992-93.
17 For example, the Motu and Mohaka rivers.
In the face of these changes, efforts to find new gas sources have increased, and some new reserves have been identified, including within the Maui mining licence area. New Zealand’s gas inventory has also been extended by development of the Pohokura gas field (commenced operation in 2007) and the Kupe gas field (commenced operation in late 2009). However, the new reserves that have been identified and/or developed to date are on a much smaller scale than the original Maui field.

As Maui gas reserves declined, gas prices rose, more than doubling compared to historical levels. Contact Energy has also made public statements about the challenge of rising gas prices and a reduction in supply flexibility, which is now being offered at a significant premium to underlying gas costs\(^\text{19}\).

Higher gas prices will be partially mitigated by the higher efficiency of modern gas-fired power plants, however the efficiency benefits are not considered to be sufficient to fully offset the impact of increased fuel costs. Developers of gas-fired stations also face uncertainty associated with the possible cost of dealing with greenhouse gas emissions, as illustrated in Figure 12.

This figure demonstrates that an emission charge equivalent to $15/t CO\(_2\)e would result in an additional cost of around 0.6 cents per kWh for a modern gas fired power station. With future gas price expectations of $7-9 per gigajoule (GJ), wholesale electricity prices would need to be around 7-8.5c/kWh or more for gas-fired generation projects to be economic. If the market price of emissions rises to $45/t CO\(_2\)e wholesale electricity prices would need to rise to 8.5-10c/kWh or more for gas-fired generation projects to be economic.

\(\text{18}\) Combined cycle gas-fired power stations have been commissioned at Southdown in 1996 (now owned by Mighty River Power), Stratford in 1998 (now owned by Contact Energy), Otahuhu in 1999 (Contact Energy), and Huntly in 2007 (Genesis Energy).

\(\text{19}\) See http://www.contactenergy.co.nz/web/pdf/financial/ar_20080923_annual_report.pdf
5.5 Coal

New Zealand’s only operational large-scale coal fired station is at Huntly in the Waikato region. This station is primarily fed coal from the local area supplemented by imports. There are coal reserves in the region that could be developed to sustain further thermal power station development.

In 2005 Solid Energy reassessed its reserves and reported that the remaining recoverable high quality coal in the Waikato region was of the order of 200 million to 300 million tonnes\(^\text{20}\). However, it also became apparent that the cost of recovering those remaining reserves would be relatively high.

Although several parties have investigated coal-fired options for new development\(^\text{21}\), no developments have proceeded and some have been abandoned\(^\text{22}\).

Although all major coal-fired developments in the North Island appear to have been shelved, there has been speculation that lignite reserves in Southland might be tapped for future development. These reserves are very large, and could underpin New Zealand’s electricity demand for many years. However, no party has yet announced specific development plans based on a lignite-fired station. This probably reflects that lignite stations would face two significant hurdles:

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\(^{21}\) For example, Fonterra plans dual-use Taranaki power plant; The Press; November 2004;.

\(^{22}\) For example http://www.mightyriverval.co.nz/News/Detail.aspx?id=894
• Southland is remote from the North Island population centres, which accounted for around 66% of all electricity demand in New Zealand in 2010\textsuperscript{23}, meaning that electricity from a significant new development would need to be transmitted a considerable distance. There are two costs which arise with this. First, existing transmission infrastructure would need to be upgraded. Second, even with an upgrade, transmission losses are significant, putting the project at a cost disadvantage compared with options closer to major load centres. The alternative of shipping the lignite to a station closer to a major load centre is also costly, especially since the energy density is significantly lower than other grades of coal;

• Lignite fired stations have high carbon dioxide output, relative to other thermal technologies. Until an economic means of capturing and reliably storing carbon dioxide emissions has been found, it is considered unlikely that this resource will be developed for electricity generation. Furthermore, even though there is considerable effort being deployed on developing carbon capture and storage technology, it is not expected that it will be available for commercial use in the near term.

Given current coal technology and New Zealand’s commitment to the ETS, breakeven prices for green-field large scale coal fired power stations are expected to be 9c to 11c/kWh or more, depending on the fuel costs.

\textbf{Figure 13: Economics of new coal-fired generation}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure13.png}
\caption{Economics of new coal-fired generation}
\end{figure}

\textit{Source: Concept estimates}

\textsuperscript{23} MED Energy Data File 2011.
Investors in new coal-fired plant would also be especially exposed to any increase in the cost of carbon over time. The extent of this exposure is illustrated by Figure 13 which illustrates the break-even costs for new coal-fired plant at different levels of carbon price. A $15/t CO$_2$e increase in the cost of carbon would lift the break-even price by almost 1.4 c/kWh. This contrasts with modern gas-fired plant, which would suffer a penalty of less than 0.6 c/kWh for the same increase in carbon costs.

Therefore, it is not expected that any major new coal-fired power stations will be developed in New Zealand in the near term.

### 5.6 Wind generation

New Zealand is recognised as having a world class wind resource, because of the country’s geographic position spanning the “Roaring Forties” latitudes. While this resource position provides a favourable backdrop, the attractiveness of individual development sites varies across the country, reflecting factors such as the:

- Specific wind conditions at each site, including the wind speed, variability, and flow characteristics;
- Geographic location of the development, which can affect project revenues because wholesale electricity prices vary across the country;
- Relative ease of obtaining land owner and resource consents;
- Cost of connecting to the transmission grid or host distribution network; and
- Local terrain and access to transport infrastructure, which affects construction costs.

Almost 600 MW of wind generation is currently operating in New Zealand, with Meridian Energy, New Zealand Windfarms, and Trustpower, providing the main contributions. Over 30 potential wind farm sites, with a potential capacity of over 5000 MW, are under investigation by a wide range of parties. While wind generation is growing strongly, it is relatively new to New Zealand and still makes up a relatively small proportion of total electricity supply\(^{24}\).

Because of its intermittent nature, integrating wind generation into the electricity system can pose some challenges. In particular, as noted in Section 4.2, electricity supply must be managed to exactly match varying demand at all times. This is more difficult to achieve in a system where a large component of the supply mix is itself also varying. It is also more challenging to achieve in regions where transmission constraints limit the ability to export surplus wind power, or to import back-up energy services from outside the region.

Section 6 provides some more in-depth discussion of wind farms and the issues involved with integration.

\(^{24}\) Wind comprised approximately 4% of total generation in 2010 (Energy Data File, July 2011, Ministry of Economic Development).
5.7 Geothermal generation

Technically at least, it has been estimated that there is a significant amount of geothermal development potential (of the order of 10,000 GWh/year\textsuperscript{25}) available in New Zealand. However, from an economic perspective, high quality geothermal development options are limited and there is some doubt about the ability to develop this potential fully and within a reasonable timeframe\textsuperscript{26}.

In respect of those projects that appear feasible, production costs are generally estimated to be in the range 7-8.5 c/kWh, making it one of the cheapest renewable options. Unlike wind and hydro generation, it can also operate at high load factors.

Geothermal operation produces some greenhouse gas emissions, but emissions per unit of electricity produced are typically much lower than for fossil fuel plant. Geothermal development can also have detrimental local environmental effects. The extraction of geothermal fluids can reduce the pressure in underground reservoirs and cause land nearby to sink or local hot pools and geysers to decline.

The potential for geothermal electricity is limited by the available sites and resource sustainability. Virtually all of the available sites are concentrated in the Taupo/Bay of Plenty Volcanic Zone.

Following the commissioning of several recent projects, the capacity of New Zealand geothermal power stations has increased to over 700 MW and they are operated by a range of participants.

5.8 Non-traditional supply options

A number of other supply options exist including biomass, solar and tidal power.

Biomass

Biomass projects that use wood processing waste or other organic material, and landfill gas and biogas schemes have been developed in New Zealand on a relatively small scale. In particular, there are a number of small landfill gas power stations providing a total of approximately 20 MW electricity supply.

There is further biomass potential in New Zealand given the amount of forestry and agriculture. However, securing access to economic fuel resources is expected to constrain development to modest levels. The Electricity Commission has estimated that there could be potentially 230 MW of biomass by 2040\textsuperscript{27}. As electricity prices rise and technological enhancements occur, electricity supply from biomass will probably become more attractive. It is already used as a significant source of heat for processes such as timber drying. While this trend is likely to continue, it is considered


\textsuperscript{26} The Government is currently reviewing access to geothermal resources. See the Ministerial Review of Electricity Market Performance: http://www.med.govt.nz/upload/69725/volume1.pdf

\textsuperscript{27} Reported in the Statement of Opportunities – September 2010
unlikely that biomass developments will be sufficient to supplant the need for new conventional generation in the foreseeable future.

Cogeneration

A number of cogeneration plants – where the waste heat from the generating plant is used for process heating – have been developed in New Zealand. Most of these tend to be relatively small although there are larger plants, such as Fonterra’s Whareroa Cogen CCGT, which has a capacity of 70 MW, and it is reasonable to assume that further developments will occur. The economics tend to depend on factors other than just the price of electricity. It is expected that similar trends to recent years will continue with a number of relatively small scale developments.

Other generating technologies

A number of emerging technologies show promise for the future. Although abundant, solar power is currently expensive to harness due to the relatively high cost of photovoltaic cells. The Electricity Commission has suggested that costs will decrease over time, but could remain as high as 25 c/kWh. Technologies that may have greater commercial potential include wave and tidal power, with Crest Energy having recently been granted consents for a tidal project in the Kaipara harbour.

5.9 New generation costs

A number of organisations have published estimates of the cost of developing new generation projects. This information can be used to derive estimates of the cost of electricity from new generation sources, expressed as the electricity price required for the new generation project to breakeven (often referred to as long run marginal cost, or LRMC).


While each organisation has its own view about the costs and quantities available for the various generation types, observations that can be made include:

29 Solar powered water heating is also increasing. While this is expected to reduce the rate of electricity demand growth, this technology does not generate electricity.
30 Reported in the Statement of Opportunities – September 2010
31 A preliminary report to the Ministerial Review of Electricity Market Performance by the Electricity Technical Advisory Group and the Ministry of Economic Development,
• Most organisations consider that new geothermal supply is among the most cost effective options available in New Zealand;

• Significant volumes of new geothermal supply are expected to be available at competitive prices and Electricity Commission scenarios include up to 750 MW of new geothermal capacity by 2020;

• With a price of emissions for electricity generators in the range of $20-$30 per tonne of CO₂e, coal-fired thermal power stations are unlikely to be economic, relative to other alternatives;

• With a price of emissions for electricity generators in the range of $20-$30 per tonne of CO₂e emitted, gas-fired thermal power stations are unlikely to be economic, relative to other alternatives;

• New hydro development opportunities at economic costs are unlikely to be available in large scale quantities;

• With a price of emissions for electricity generators in the range of $20-$30 per tonne of CO₂e emitted, a number of wind farm developments are considered to be the next most attractive following geothermal.

Figure 14 highlights these issues by illustrating the range of estimates of the cost of electricity generated from possible new projects through the next ten years, and comparing these with the range of prices at which base-load strip electricity contracts have traded for the period 2011-2014.

Note that forward electricity contracts have tended to trade at prices that are above the cost of electricity from new geothermal power stations and close to the cost of wind farm developments. This is considered to be because geothermal developments alone are unlikely to be sufficient to meet the demand for new electricity generation, and there is a wide expectation that wind farm developments will need to play a large role.
This section has explored options for new electricity generation projects to meet the growth in demand for electricity through the next 20 years.

It highlights that successive government policies have placed an emphasis on the development of renewable sources of generation and this has been shaping generation choices. The application of the Emissions Trading Scheme to the electricity sector has reinforced this influence and new generation development is now strongly focussed on geothermal and wind farm development as a consequence.

Source: MED, Concept, Meridian Energy, Contact Energy, Infratil and Electricity Commission; EnergyHedge and ASX futures trades 2009-2011
6 Integrating Wind Farms in the New Zealand System

This section explores some of the issues associated with integrating wind farms into the existing power supply system in New Zealand. This is an important issue because there are some concerns that the future prevalence of wind farm development could lead to a situation which exacerbates security of supply risks.

6.1 Short term flexibility

Figure 8 in section 4.3 highlighted that New Zealand has a relatively high proportion of hydro generation. A significant benefit is that, on a day to day basis, hydro power stations with the facility to store hydro inflows are able to respond to short term changes in market demand, providing important capability that the System Operator can rely upon to match supply and demand on a continuous basis.

This short term flexibility will also support the growth of non-hydro renewable supply developments that are intermittent, such as wind, or inflexible, such as geothermal. In this regard, the New Zealand electricity system is well placed compared to many other countries.

Figure 15: Generation mix in other jurisdictions

Source: Derived by Concept Consulting Group from various sources

Many countries that have developed large amounts of wind generation have considerably lower proportions of hydro generation, are more reliant on thermal generation, and therefore need to rely
more on fast start gas turbines to support the development of wind generation. For example, Figure 15 illustrates the share of different generation technologies in a number of countries, with particular focus on hydro and wind generation.

The figure highlights that the proportion of hydro generation in New Zealand is high compared to other countries, some of which also have considerably higher proportions of wind generation. This suggests that New Zealand is well placed to support additional generation with short term intermittency, such as the proposed CHWF Project. In this sense, hydro and wind generation can be viewed as complementary.

Section 4.7 highlighted that the design of the electricity market is intended to provide price signals and cost signals that encourage the most economic mix of power stations to meet demand. To this end, generation that is ‘firm’ at times of scarcity will tend to earn a higher generation-weighted average price, and developments in the pricing and allocation of costs for ancillary services are expected to reward flexible generation by allocating costs to inflexible generation.

These factors will be taken into account by Genesis Energy when it is making a decision about when to proceed with CHWF.

6.2 Seasonal and year-to-year flexibility

On a seasonal and year-to-year basis, the availability of hydro energy supply can vary considerably depending on inflows to hydro catchments. This is illustrated in Figure 16, which shows monthly hydro inflows and hydro generation (both in GWh per month) over the period 2005 to 2010.

Figure 16: Monthly NZ hydro inflows and generation (Jan 2005 to Feb 2010)

Source: Electricity Authority Centralised Dataset
This figure illustrates the important role of hydro storage in allowing inflow variability to be managed, while matching the hydro generation to demand, and minimising spill. The hydro inflow peaks are captured in the storage lakes and releases from the storage lakes are used to supplement hydro inflows when they are low.

Section 4.4 highlighted how the management of hydro storage is complemented by thermal generation. When hydro supply is plentiful, thermal generation is backed off and when hydro supply is low, thermal generation is increased. This is an important function of the electricity market, which allows hydro generators to adjust offer prices so that more or less thermal generation is scheduled. Hydro storage and thermal supply thus combine to provide important seasonal and year-to-year energy supply flexibility.

There has been speculation that, because wind generation is weather dependent like hydro inflows, it will tend to increase dry year security of supply risks. In other words, because wind and precipitation may be based on the same underlying weather patterns, there may be a risk that periods of low hydro inflows may coincide with periods of relatively low wind speed. For example, it has been observed that generation from existing wind farms was low during the 2008 hydro drought.

Figure 17 compares monthly average hydro inflows and regional wind speeds during 1991 and 1992 which were both years affected by hydro droughts. Observation of this chart confirms that wind speeds were relatively low in the Otago region at times when inflows were low, but that other regions demonstrated less correlation.

**Figure 17: Average wind speed vs NZ hydro inflows 1991/2**

The critical period for dry year security in New Zealand is over the winter. This is when demand is greatest, and when hydro inflows tend to be at their lowest (as illustrated by Figure 18).

**Figure 18: Weekly GWh equivalent hydro inflows across the seven main New Zealand hydro schemes**

![Weekly GWh equivalent hydro inflows across the seven main New Zealand hydro schemes](image)

*Source: Concept analysis using centralised data set data*

Because of this seasonal pattern, one of the key measures of supply security used in New Zealand is the so-called ‘winter energy margin’ which calculates the extent to which New Zealand’s total expected generation capability is greater than expected demand for the months of April to September. The winter energy margin is calculated as part of the Annual Security Assessment undertaken by the System Operator.

Analysis of the extent to which there may be some correlation between wind generation output and hydro inflows was undertaken by the Electricity Commission in 2010, culminating in a report in July 2010. The analysis compared ‘synthetic’ historic daily wind-speeds at 12 locations around the

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32 The seven schemes are: Manapouri, Clutha, Waitaki, Waikato, Cobb, Coleridge, and Waikaremoana.

33 Responsibility for undertaking the Annual Security Assessment shifted from the Electricity Commission to the System Operator in 2010 as part of the package of industry reforms implemented by the government.

34 “Correlation between wind generation output and hydro inflows”, Electricity Commission, July 2010.
country covering 19 years (1990-2008) with the hydro inflows for the same period. One of the first conclusions from the analysis was that there is a statistically significant seasonal pattern to wind flows. This is illustrated in Figure 19.

Figure 19: Seasonal patterns in synthetic wind generation output

![Figure 19](image)

Source: “Correlation between wind generation output and hydro inflows”, Electricity Commission, July 2010

The report noted that the extent of wind seasonality varied across the country, and thus the relative location of any wind farms would influence the overall extent of wind seasonality exhibited by New Zealand’s wind generators. After considering a range of scenarios for potential wind farm locations the report concluded that, for the purposes of calculating winter energy margins, output from wind generators over winter (April-September) should be considered to be 6% less than the average over the year.

While this 6% reduced wind output on average over winter months may be correct, it would be too simplistic (and an overestimate) to assume, for the purpose of calculating winter energy margins, that the output of wind farms should be reduced by 6%. This is because wind generation output must be greater than average over the six month summer period, if it is 6% lower than average over

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35 The report explains that this data was termed ‘synthetic’ in that it combined wind monitoring mast data at various sites around the country from a more limited time span with NIWA station data over a longer time period, in order to create the resultant daily wind speed record for the 12 sites over the 19 years.
the winter period. This increased summer wind generation will tend to have the effect of displacing some discretionary hydro generation, with the result that the level of the hydro reservoirs will tend to be higher at the start of the winter period, with consequential winter security of supply benefits. The extent of this effect has not been analysed by Concept to determine how much this increased summer wind generation offsets the effect of reduced winter wind generation.

The Electricity Commission report also considered whether there was a correlation between unusually dry / wet hydro inflows and unusually calm / windy wind flows. It identified that for ten out of the twelve wind locations, there is a moderate correlation with hydro inflows. The exceptions were the Auckland and Northland regions, which appeared to have wind patterns that were near-independent of inflows. The degree of correlation with national hydro inflows varied across the different wind regions as shown in Figure 20.

Figure 20: Correlation between national hydro inflows and wind

![Correlation chart](image)

Source: “Correlation between wind generation output and hydro inflows”, Electricity Commission, July 2010

The Electricity Commission noted that because most wind regions had a some correlation with hydro inflows, the geographical diversity of wind farms was unlikely to significantly reduce any dry-year correlation effects (except for the Northland and Auckland regions noted above). On average it noted that wind flows during ‘dry’ conditions were approximately 4% less than during ‘average’

36 The report commented that wind in these latitudes appears to be driven by different climate factors, and that NIWA comments appear to support this conclusion.
conditions. It further suggested that this 4% figure should be used to adjust the contribution of wind farms for the purpose of calculating winter energy margins.

Although Concept has not replicated the analysis undertaken by the Electricity Commission to verify whether the 4% value is correct, nor done any work to determine whether the adjustment factor approach proposed for the winter energy margin analysis is appropriate, the Commission analysis does confirm that there is some correlation between hydrology and wind flows. This correlation will tend to exacerbate any hydrological variance in generation, and likely increase the level and cost of thermal ‘hydro-firming’ generation required.

However, it should be noted that this hydro-wind correlation is relatively minor. For example:

- The Electricity Commission analysis indicated that “The difference in expected wind output between a dry winter and an average winter is statistically significant, but relatively small. ... In terms of multi-year security assessments, it is well below the margin of error. ... By contrast, there is a much greater difference between national hydro inflows in a 1-in-10 dry Apr-Jun quarter and those in an average Apr-Jun quarter – approximately 20% of average Apr-Jun inflows.”

- The level of wind output is currently insignificant relative to that of hydro output. Figure 21 highlights that hydro inflows are by far the dominant underlying source of energy supply variability. Even if wind generation were to increase significantly, hydro variability would continue to be the dominant source of energy supply variability.

**Figure 21: Monthly NZ hydro inflows and wind farm supply (Jan 2005 to Feb 2010)**

![Graph showing monthly NZ hydro inflows and wind farm supply from January 2005 to February 2010.](Source: Electricity Authority Centralised Dataset)
Further, it should be noted that as the New Zealand power system becomes increasingly *capacity constrained*, a number of thermal power stations will likely be built to provide peak MW capacity that can also be used to provide dry year energy. This will have the effect of increasing the New Zealand winter energy margin, and significantly reducing the impact of a given dry-year event.

This combination of the relatively small contribution to dry-year energy variability from wind farms, and the likely ongoing reduction in the impact of dry-year events due to thermal plant being built for capacity adequacy purposes being able to provide additional dry year energy, means that the consequences of increased wind generation on dry-year energy availability are likely to be relatively minor.

It should also be noted that any correlation between low wind periods and dry periods will likely be reflected in increased differentials between market prices in a dry-year and other years, resulting in an adverse price correlation for wind farms (i.e. market prices will tend to be lower when wind generation is higher, and vice versa). This reduction in the generation-weighted average price received by wind farms must be factored into the decisions by potential wind developers as to whether the economics of a particular project stack-up.

This is exactly the same effect as described in section 4.7, and is the mechanism by which the electricity market design tends to ensure that all generators face the correct economic signals. In other words, plant that is ‘firm’ at times of scarcity will capture the higher market prices associated with such scarcity and thus earn a generation-weighted average price that is at a premium to the time-weighted average price, while plant that is not ‘firm’ at times of scarcity will suffer a generation-weighted average price that is a discount to the time-weighted average price.

These factors must be taken into account by Genesis Energy when it is making a decision about when to proceed with CHWF.

### 6.3 Integrating Wind Farms into the New Zealand System

There are undoubtedly challenges associated with integrating wind farms into any power system. These challenges include the intermittent nature of the production and the implications of this for real-time system operation, how much transmission capacity is required to accommodate it, and whether additional flexible “peaking” power stations are required to accommodate it. In New Zealand these questions have been the focus of work undertaken by Goran Strbac for Meridian Energy and by the Electricity Commission. The Strbac study concluded that:

- New Zealand is well-placed to accommodate wind farms because of its substantial base of flexible hydro power stations;

- The additional capacity costs associated with real-time operation constraints are relatively small in the short-term but may rise slightly in the longer-term;

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37. New Zealand Wind Integration study; Goran Strbac, Imperial College of London, April 2008.
38. Wind Generation Investigation Project; Electricity Commission, 2005.
• Wind power contributions up to 20% of energy could likely be accommodated without large cost penalties.

The Electricity Commission\(^{39}\) has been investigating the implications of wind farm development for some time through a number of particular projects that stemmed from its original Wind Generation Investigation Project in 2005. The focus of the Commission’s work has been to determine what changes would need to be made to the rules and industry arrangements to enable integration of a large volume of wind generation into the New Zealand power system and electricity market, rather than to address what capacity of wind could be accommodated within the New Zealand power system without materially adding to costs.

Accordingly, the Commission’s work has been directed at the effects of wind generation variability on the pre-dispatch and dispatch processes, on transmission assets loadings, on the ability to manage frequency and voltage quality, and on the stability of the power system. Initial conclusions suggest that the early focus should be on assessing the impacts of unpredictable wind generation on the pre-dispatch process.

Although the Electricity Commission has not attempted to assess what capacity of wind could be accommodated within the New Zealand power system, in developing the generation scenarios for the purpose of the 2010 Statement of Opportunities, the Commission limited wind generation to a maximum of 20% of total electricity generation. The current proportion of wind generation is less than 4%, however if all wind farm projects that have received resource consents were to proceed by 2020 (noting that some are on hold and some are subject to appeal) the proportion would rise to approximately 14%.

### 6.4 Integrating Castle Hill Wind Farm

When CHWF proceeds, it will represent one of the largest new generation developments to take place since the original Huntly power station was commissioned in 1985. A key issue is how such a large development will fit into the local transmission infrastructure and be integrated into the national power system.

The first issue that we have explored is the extent that CHWF output is likely to be correlated with output from other wind farms in the region. In order to explore this issue we have used half hourly data that has been synthesised by Aurecon New Zealand (for Genesis Energy) using wind speed readings at the CHWF site and compared this with actual output from the Tararua and Te Apiti wind farms.

Figure 22 compares the output from a notional 100MW CHWF (expressed in GWh per month) with the output from the Tararua wind farm over the period from September 2004 to December 2008 and illustrates that there is likely to be a very close relationship between the outputs from the two wind farms.

\(^{39}\) Now the Electricity Authority.
Figure 22: Correlation between CHWF and Tararua Wind Farm

Source: Concept Consulting Group using Aurecon data and CDS

Figure 23: Correlation between CHWF and TeApiti Wind Farm

Source: Concept Consulting Group using Aurecon data and CDS
Figure 23 compares the output from a notional 100MW CHWF (expressed in GWh per month) with the output from the Te Apiti wind farm over the same period and also illustrates that there is likely to be a very close relationship between the outputs from the two wind farms.

These figures suggest that there will be many periods where the output from the wind farms in the region will all be relatively high. In order to explore the impact this might have on the electricity supply system Concept has simulated the output from CHWF and how it might impact upon the flow of electricity through the North Island transmission system.

We have undertaken the simulation analysis using half hourly data synthesised by Aurecon New Zealand and the TAO modelling framework\(^40\) developed by Concept in 2007. The methodology adopted has been to choose the year 2016 and to simulate two scenarios – one without CHWF operating and one with CHWF operating, and to investigate the possible differences in electricity flows through the network and possible differences in transmission losses and location-based spot prices. In order to make the two scenarios realistic some new generation projects in the “with CHWF” scenario have been deferred such that the two scenarios have similar capacity and energy margins and a similar balance between supply and demand.

This analysis should not be regarded as conclusive or definitive about likely electricity market outcomes. In particular, it is noted that any differences in outcomes between the “without CHWF” and the “with CHWF” scenarios are sensitive to the choice of other new power stations to be deferred in the “with CHWF” scenario. Nevertheless, the results are considered to be illustrative of the likely impact of CHWF on operation of the New Zealand electricity market.

The results of this analysis are described in Appendix 3.

The key findings from this analysis are summarised as follows:

- CHWF will provide a material increase in the contribution from wind production (particularly if it is configured to supply 600 MW or more) that will generally fit well within the arrangements for dispatching generation to meet North Island demand;

- During some periods of low summer electricity demand, very high levels of production from the lower North Island wind farms could potentially displace production from hydro power stations and result in spill;

This section has explored some of the issues associated with integrating wind farms into the existing power supply system in New Zealand and CHWF in particular.

It highlights that currently the contribution of supply from wind farms is very small relative to the large flexible hydro resource and this means the New Zealand is well placed to develop a bigger wind farm sector. Although there is some correlation between dry hydro periods and periods with low wind this is not considered to be a determinative factor in security of supply outcomes, and as the New Zealand power system becomes more capacity constrained it is considered likely that more peaking plants will be added to the system and create more flexibility to accommodate interment supply sources.

\(^40\) TAO stands for “Transmission Augmentation and Optimisation”
To the extent that there is a correlation between low wind periods and dry periods this will likely be reflected in increased differentials between market prices in a dry-year and other years, resulting in an adverse price correlation for wind farms. This should be factored into the decisions by potential wind developers when assessing the economics of a particular project.

Simulation analysis undertaken by Concept suggests that the electricity production from CHWF should be readily accommodated within the North Island power system.
7 Potential Benefits of Castle Hill Wind Farm

7.1 Meeting electricity demand growth

Section 3 highlighted that electricity demand is forecast to continue growing, albeit at slightly lower rates that observed in the past, and that there is considerable uncertainty about the need for new generation over time. A number of new projects are either under construction or are expected to commence construction soon. However these projects are only expected to add around 230 MW (capable of supplying approximately 1,700 GWh/year) of new generation by 2014. A range of other projects have resource consents, but no decisions to proceed have been made and many projects are on hold. There is a risk that many consented projects will not proceed at all as a result of economic factors or availability of fuel. It is therefore important that there are viable new generation options to meet expectations of demand growth. CHWF would provide a significant contribution to meeting the additional requirements for generation, as illustrated in Table 4.

Table 4: Castle Hill Wind Farm contribution to new capacity requirements by 2020

<table>
<thead>
<tr>
<th>CHWF Capacity</th>
<th>Contribution to meeting demand growth</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MED very low growth</td>
</tr>
<tr>
<td>2,100 GWh per annum</td>
<td>56%</td>
</tr>
<tr>
<td>3,000 GWh per annum</td>
<td>80%</td>
</tr>
</tbody>
</table>

Source: Concept Consulting Group

CHWF is expected to generate approximately 2,100 GWh pa (and could contribute up to 3,000 GWh pa), and should therefore make a material contribution to meeting projected demand growth. Depending upon the final size of the wind farm, and the rate of load growth, CHWF could contribute between 25% and 80% of the new capacity required to meet load growth by 2020.

In order to illustrate the materiality of this contribution, it is noted that CHFW could meet the annual needs of between 260,000 and 370,000 households.\(^{41}\)

7.2 Meeting Government renewable targets

Section 5.2 outlined the government targets for renewable electricity generation. In particular, it noted that the draft New Zealand Energy Strategy (NZES) released in July 2010 retains the aspirational target that 90 percent of electricity generation be produced from renewable sources by 2025 (in an average hydrological year) providing this does not affect security of supply.\(^{42}\)

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\(^{41}\) This estimate is based on an annual energy demand of 8,100 kWh/year per household (the national average quoted in the Ministry of Economic Development Energy Data File, July 2011).

In the recent past, the level of renewable generation has varied between 64% and 73% depending upon inflows to hydro catchments. Figure 24 illustrates the new generation capacity that would be required by 2025 in order to meet the 90% renewable target.

**Figure 24: New renewable generation capacity required by 2025 to meet renewable target**

As a renewable energy source, development of CHWF would contribute to achieving the target of 90% renewable generation by 2025. It could supply between 11% and 30% of the required renewable generation, depending upon the eventual size of the wind farm and the rate of electricity demand growth.

### 7.3 Reducing carbon emissions

In operation, the CHWF will not release any greenhouse gas emissions and as described in section 4.2 would operate in the electricity market ahead of thermal generation. Table 5 shows the greenhouse gas (carbon dioxide equivalent – CO₂e) emission rates for thermal power stations and the annual emissions that each would produce in generating electricity supply equivalent to that from the CHWF Project (for the 2,100 GWh option and for the large scale 3,000 GWh option).

CHWF is expected to produce approximately 2,100 GWh per annum (and possibly up to 3,000 GWh per annum). This amount of generation has the potential to displace between 789,000 and
1,127,000 tonnes per year of CO₂ if it displaces gas-fired generation. It also has the potential to displace between 1,700,000 and 2,700,000 tonnes per year of CO₂ if it displaces coal-fired generation. To put these figures in context, they are equivalent to a range of between 11% and 40% of all emissions from electricity generation in the year to 31 March 2010.

Table 5: Thermal generation emissions

<table>
<thead>
<tr>
<th>Thermal CO₂ emissions</th>
<th>Gas (CCGT)</th>
<th>Gas (OCGT)</th>
<th>Oil (OCGT)</th>
<th>Coal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tonnes CO₂e/GWh</td>
<td>375</td>
<td>506</td>
<td>688</td>
<td>916</td>
</tr>
<tr>
<td>kilotonnes CO₂e @ 2100 GWh pa</td>
<td>789</td>
<td>1063</td>
<td>1,445</td>
<td>1,924</td>
</tr>
<tr>
<td>kilotonnes CO₂e @ 3000 GWh pa</td>
<td>1,127</td>
<td>1,519</td>
<td>2,064</td>
<td>2,749</td>
</tr>
</tbody>
</table>

Source: Concept Consulting Group

It is difficult to ascribe reductions in greenhouse gas emissions to individual projects but meeting an increased portion of demand from renewable energy sources will inevitably assist in avoiding greenhouse gas emissions from thermal power stations.

7.4 Diversifying generation supply

As highlighted in Section 4.3 the New Zealand supply mix is currently dominated by hydro and thermal generation. As a result, the nation has exposure to a number of risks including:

- Dry years where inflows to hydro storage lakes are significantly below average for a sustained period (as in 2001 and 2008);
- Uncertainty over the prices and terms of future gas supplies for gas-fired generation;
- Uncertainty over the cost of mitigating greenhouse gas emissions for existing (and any new) coal and gas-fired generation.

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43 This ignores any transmission system losses.
45 Combined Cycle Gas Turbine. Modern high efficiency gas powered generators similar to the Contact Energy Otahuhu and Taranaki Combined Cycle Gas Turbine power stations and the e3p power station at Huntly owned by Genesis Energy.
46 Open Cycle Gas Turbine. Typically used as peaking plants, such as that developed at Stratford by Contact Energy.
47 For example, the Whirinaki plant purchased by the government in 2004 for dry year reserve energy purposes.
48 Assuming 53.3, 68.8 and 89.4 tonnes of CO₂ per TJ of natural gas, diesel and sub-bituminous coal respectively (“NZ Energy Greenhouse Gas Emissions”, Ministry of Economic Development, 2009); and plant net heats rate of approximately 7,050, 9,500, 10,250 and 10,000 GJ/GWh for CCGT, gas OCGT, coal-steam and diesel OCGT plants respectively.
Some of these exposures will reduce if supply from geothermal generation is increased. However geothermal generation alone is not expected to be sufficient to meet the need for new generating capacity. Wind generation currently provides a small contribution to meeting electricity demand (less than 4%) and expanding it offers an opportunity to further diversify supply sources and reduce overall risks to future electricity supply.

### 7.5 Supply and demand within the region

CHWF will feed electricity into the central electricity region. Note that the Tokaanu and Rangipo power stations are included in the central region, but they feed electricity into the transmission system just south of Lake Taupo. In order to illustrate the supply and demand that is most relevant to the wider Tararua region, Figure 25 shows the annual load and electricity generation for the central region from 2004 to 2010, excluding generation from Tokaanu and Rangipo, and excluding supply points that do not receive their supply predominantly through the Bunnythorpe substation.

**Figure 25: Load and generation in the Central region**

![Graph showing load and generation in the Central region from 2004 to 2010.](image)

*Source: Electricity Authority Centralised Data Set*

This chart highlights that, despite increasing electricity generation, the region predominantly supplied through Bunnythorpe substation has consistently been a net importer of electricity (demand has been greater than supply). Supply within the region comes predominantly from the

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49 The central electricity region is defined in the Transpower Annual Planning Report 2011 and comprises the areas of Manawatu, northern Wairarapa, southern Hawkes Bay, King Country, and Taupo.
Mangahao hydro station, and the Tararua and Te Apiti windfarms. CHWF will change the generation dynamic within the central region, increasing security of supply, and when all generation is running the region will become a net exporter of electricity.

7.6 Other regional projects

The Tararua region has a significant and relatively reliable wind resource. As a result, it is a popular region for wind farms. The closely related northern Wairarapa and southern Hawkes Bay regions are also proposed for wind farm development. Table 6 summarises the existing and potential wind farms in these regions.

Table 6: Existing and potential wind farms in the wider Tararua region

<table>
<thead>
<tr>
<th>Wind Farm</th>
<th>Status</th>
<th>Owner/developer</th>
<th>Size (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Te Apiti</td>
<td>Existing</td>
<td>Meridian</td>
<td>90</td>
</tr>
<tr>
<td>Tararua Stages I, II &amp; III</td>
<td>Existing</td>
<td>Trustpower</td>
<td>161</td>
</tr>
<tr>
<td>Te Rere Hau</td>
<td>Existing and under construction</td>
<td>NZ Windfarms</td>
<td>48</td>
</tr>
<tr>
<td>Te Rere Hau Extension</td>
<td>Consent granted</td>
<td>NZ Windfarms</td>
<td>12</td>
</tr>
<tr>
<td>Turitea</td>
<td>Draft consent granted</td>
<td>Mighty River Power</td>
<td>183</td>
</tr>
<tr>
<td>Waitahora</td>
<td>Consent granted</td>
<td>Contact Energy</td>
<td>156</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>650</strong></td>
</tr>
</tbody>
</table>

Source: Energy News

This table highlights that the existing wind farm resource of 299 MW is likely to be supplemented by an additional 351 MW if all projects in the region are developed.

CHWF could almost double the resource in the region if it proceeds. Simulation analysis confirms that the transmission system can cope with this additional resource (on the assumption that CHWF will inject supply into the Bunnythorpe-Linton transmission).

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Note that Te Rere Hau and Hau Nui wind farms are not included in the Electricity Authority Centralised Dataset because they provide electricity into the local distribution networks and are netted off the demand included in the chart.
This section has explored the benefits CHWF will convey to the electricity supply system in New Zealand. In particular it has highlighted that CHWF should:

- Contribute strongly to meeting the growth in demand for electricity;
- Contribute strongly to meeting the government target for 90% renewable generation by 20230;
- Contribute strongly to reducing greenhouse gas emissions;
- Help to diversify the electricity supply mix;
- Increase security of supply in the central electricity region.
Appendix 1. List of Abbreviations and Terms

AEE  Assessment of Environmental Effects
CCGT  Combined Cycle Gas Turbine
CDS  Central Data Set (provided by the Electricity Commission/Authority)
CHWF  Castle Hill Wind Farm
Code  Electricity Industry Participation Code – replaced the EGRs and is administered by the Electricity Authority
CO₂e  Carbon Dioxide Equivalent (in greenhouse gas terms)
EA  Electricity Authority
EC  Electricity Commission
EDF  Energy Data File (published by MED)
EGRs  Electricity Governance Rules (replaced by the Electricity Industry Participation Code)
ETS  Emission Trading Scheme
GDP  Gross Domestic Product
GJ  Giga Joule
GWh  Giga Watt Hour
HVDC  High Voltage Direct Current link that connects the North and South Islands
LRMC  Long Run Marginal Cost
MED  Ministry of Economic Development
MW  Mega Watt
MWh  Mega Watt Hour
NZES  New Zealand Energy Strategy
OCGT  Open Cycle Gas Turbine
PJ  Peta Joule
SOO  Statement of Opportunities (published by the Electricity Commission up until 2010)
TAO  Transmission Augmentation and Optimisation Model
Appendix 2. Electricity Market Overview

This appendix describes the commercial elements of the electricity market underpinned by the physical elements described in section 4 of this report. It is useful to understand these commercial arrangements when considering how CHWF will impact on the electricity market.

Spot market

The wholesale electricity market is centred on a spot market, where generators compete by submitting offers to generate electricity on a half-hourly basis. Generators that have their offers to generate accepted are dispatched by the System Operator and receive the spot price for their output in a given half hour (often called a trading period).

Figure 26 provides a stylised illustration of the spot market, demonstrating how generator offers are stacked in price order to determine which generators will run during the trading period, and how the generation offer that intersects demand sets the price for the trading period. Using this methodology, a schedule of generators required to run is developed for each trading period, along with a spot price. The System Operator coordinates the dispatch of all generators in accordance with the schedule51.

Figure 26: Spot market pricing model

The spot market arrangements are designed to ensure that generators with low operating costs are able to operate ahead of other generation with higher operating costs. CHWF will have very low operating costs, hence it will tend to be offered and dispatched ahead of other, costlier generation.

51 In practice, the arrangements are more complex than the figure of this description implies, since the dispatch and pricing schedules are prepared separately (prices for each trading period are determined “ex post” the following day).
Retailers (and some large consumers) purchase electricity through the spot market and pay the spot price for the electricity that their customers consume in each half-hour. Generators are paid the spot price for the electricity that they generate and supply to the spot market in each half-hour.

The half-hourly spot prices fluctuate according to demand, generation and grid conditions at the time, as illustrated in Figure 27.

**Figure 27: Half-hourly spot market prices at Bunnythorpe - week beginning 29 March 2009**

Source: Electricity Commission (Central Data Set)

Generators and retailers/larger consumers also enter into bilateral wholesale contracts to mitigate their exposure to future spot price uncertainty. Contract prices reflect expectations of market conditions/spot market prices, and buyer and seller commercial risks, over time.

Although spot market prices vary half-hourly, most retail customers are shielded from this volatility, with retail prices typically comprising a fixed fee and a fixed price for each unit of electricity used. Over time, retail prices are influenced by longer term trends in wholesale market prices.

**Location Specific Pricing**

Spot market prices, as illustrated in Figure 27 are formed for each trading period, at over 200 locations across the national grid (often described as “nodes” with “nodal prices”). The spot price (or nodal price) varies from location to location (or node to node) depending upon the pattern of transmission losses and transmission constraints across the national grid. These nodal prices reflect the marginal variable cost of generating and transporting electricity around the country and tend to
be high where local demand exceeds local generation and low where local generation exceeds local demand.

Figure 28 illustrates the spot prices at four different nodes on one day: Otahuhu (Auckland), Bunnythorpe (where the proposed CHWF will connect to the grid), Haywards (Wellington) and Benmore (Waitaki Valley), and these prices are overlaid with the pattern of demand on the same day.

**Figure 28: Prices and load during 3 May 2010**

The figure illustrates that:

- As demand varies throughout the day, with morning and evening peaks, spot prices tend to follow a pattern with higher prices at the peak times and lower prices at other times, particularly overnight; and

- Prices in the north tend to be relatively higher than those in the south;

- In this example, prices at Bunnythorpe are close to prices at Haywards.

The pattern of prices rising up through the North Island is typical, and reflects the normal balance of generation and demand across the country, with surplus generation from the South Island flowing north to supply higher demand and flowing up through the North Island from Wellington to Northland.
Nodal pricing plays an important role in sending price signals to market participants where elements of the transmission system reach their physical operating limits. Prices will rise downstream of a transmission constraint to indicate to generators located there that they should increase production, or to retailers/purchasers that they should reduce consumption to relieve the effects of the constraint and to avert potential loss of supply to customers in the region.

By reflecting the cost of transmitting electricity from generators to where customers are located nodal prices also send important long term signals. Generators who are located a long way from the large concentrations of customers (such as the major urban areas) generally receive lower prices for their electricity than generators who are nearby. In the long run, these price signals encourage investors to build new power stations closer to where the electricity is required or, conversely, to build factories and other equipment, which use electricity, closer to where the generation is located. Importantly, nodal prices also provide signals about the merits of investing in transmission or local generation alternatives.

While other factors will also influence new supply investment decisions, such as proximity to thermal fuel and favourable wind/hydro/geothermal development sites, location-based pricing sends important signals to investors about where and when new supply and/or transmission investments are needed.

**Ancillary services**

Spot market dispatch is supported by a number of important ancillary services that enable the quality and security of electricity supply to be maintained. These services are procured through:

- Technical performance obligations on participants: For example, the Code\(^{52}\) requires generators to respond automatically to support system frequency\(^{53}\) (typically achieved through the output of generating units responding automatically through “free governor action” to changes in system frequency). Similar arrangements exist for managing system voltage levels\(^{54}\).

- Ancillary service contracts: For example, the System Operator contracts with certain generators to support the dispatch process by responding to changes in frequency (due to supply-demand imbalances).

\(^{52}\) Part 8 of the Electricity Industry Participation Code.

\(^{53}\) The New Zealand electricity system operates at a nominal frequency of 50 Hertz. If system demand, including losses, exceeds generation, the system frequency will fall as generators give up rotational stored energy. The rate of decline depends on the level of mismatch. Unless more generation is injected into the system, or demand reduced, the system frequency will continue to fall and some generators will disconnect automatically in order to avoid damage to the plant, with widespread consequent loss of supply to consumers. With too much generation on the system, generators will speed up and the frequency will rise having similar effects. These effects occur within a few seconds.

\(^{54}\) As for frequency, if system voltage levels (which unlike frequency can vary around the grid) move outside acceptable limits, equipment (generation, transmission, distribution and consumers) can be damaged and/or supply to consumers disrupted.
- The instantaneous reserves market\textsuperscript{55} in which generators and demand-side resources compete\textsuperscript{56} to provide reserve capacity to cover the unexpected loss of a large single source of generation or piece of transmission equipment.

Concerns have been expressed\textsuperscript{57} about the inherent limitations of wind generation compared to conventional generation. Wind farms are principally designed to generate as much electricity as the wind provides and have limited ability to support the power system voltage and frequency. However:

- Modern wind generators can contribute to voltage and frequency support, although at some operational cost for frequency support\textsuperscript{58}.

- Where a generator is unable to meet technical performance obligations, or it is costly to do so, under the rules it may apply to the System Operator for a dispensation and pay any identifiable resulting system costs.

- The costs of procuring ancillary service contracts are recovered on a causer pays basis where identifiable. For example, instantaneous reserves costs are allocated to the risks being covered (larger generating units and transmission elements).

- The potential impact of wind generation on ancillary service requirements is still being evaluated by the Electricity Authority but the Authority has made it clear that it expects those causing system impacts to contribute to the costs\textsuperscript{59}. For example, given the intermittent nature of wind generation, the Authority is reviewing the dispensations and cost allocation regime, and how frequency keeping costs are allocated\textsuperscript{60}.

Generation investors take these factors into account when evaluating the economic viability of potential developments. To the extent a generation development imposes identifiable system costs, the investor can expect to pay these costs. This is important as it means that different generation technologies should compete on even terms in relation to their impact on the electricity system.

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\textsuperscript{55} Generation that can automatically increase output very quickly and demand that can be automatically interrupted very quickly as system frequency falls.

\textsuperscript{56} The market selects the lowest cost combination of energy and instantaneous reserves to meet demand.

\textsuperscript{57} For example, see this section (“Factors limiting integration”) in the summary of a report on Wind Energy Integration in New Zealand, commissioned by EECA and the MED - http://www.med.govt.nz/templates/MultipageDocumentPage____4321.aspx#P46_9273

\textsuperscript{58} For example, reserving capacity to be able to increase supply when system frequency is low would involve spilling wind.

\textsuperscript{59} For example, the Electricity Commission (now the Authority) Wind Generation Investigation Project (WGIP) states “Given the provisions of the Electricity Act [2], the objective adopted by the Commission is to ensure that the EGRs and related arrangements neither penalise nor favour wind generation relative to its true system costs. i.e. the EGRs and related arrangements should ensure efficient operation of the system, while ensuring there are no undue barriers to economic generation options.”

\textsuperscript{60} The Electricity Authority wind integration work program includes a task to “Review current dispensations/ cost allocation regime in relation to technical performance obligations (to ensure a reasonably level playing field between wind and other generation types)".
**Retail electricity market and hedge contracts**

Wholesale spot prices vary from one half hour to the next, as illustrated in Figure 27 and most consumers prefer to purchase electricity at a known fixed electricity price. In order to cope with spot market price variation, while meeting consumer demand for fixed price contracts, retailers enter into contracts with generators that have the effect of providing some certainty about electricity cost. These contracts are commonly referred to as “contracts-for-differences” or “hedge” contracts because they are structured to provide difference payments referenced to spot market prices and have the effect of hedging (or fixing) electricity prices for both parties to the contract.

Hedge contracts play an important role in the electricity market by allowing retailers and generators some degree of price certainty, while preserving the important underlying price signals available through the spot market.

The five largest retailers are also generators and, to the extent that their retail supply volumes match their generation volumes, they will have a degree of internal hedging that negates the need for hedge contracts.

Note that large customers that choose to purchase electricity direct from the wholesale market also typically enter into hedge contracts with generators in order to reduce the variability of electricity purchase cost. Despite these hedge contracts, these customers remain exposed to spot prices and have an incentive to reduce demand when prices are high or to increase demand when prices are low.

**Market governance**

The Electricity Authority\(^{61}\) has a regulatory oversight role of the electricity industry through Section 15 of the Electricity Act (2010) and the Electricity Industry Participation Code (2010). The Authority has a single statutory objective to promote competition, reliable supply and efficient operation of the electricity market for the long-term benefit of consumers. The Electricity Authority’s key functions include:

- Making and administering the rules governing the electricity industry through the Electricity Industry Participation Code;
- Monitoring compliance with the code and other provisions in the Electricity Industry Act and regulations and take enforcement action;
- Undertaking market facilitation measures such as education and providing guidelines, information and model arrangements;
- Industry and market monitoring, and carrying out reviews, studies and inquiries into matters relating to the industry; and
- Contracting for market operation services and system operator services.

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\(^{61}\) The Electricity Authority replaced the Electricity Commission from 1 November 2010. See: http://www.med.govt.nz/upload/70927/summary-of-decisions.pdf
Generation investment and wholesale market competition in the new regulatory environment remains essentially the same as under the Electricity Commission. Participants such as Genesis Energy will continue to make their own assessments of opportunities to invest, subject to the commercial disciplines the electricity market imposes on them. Electricity market prices must be sufficient to support the cost of developing and operating new generation or any new investment will be uneconomic. In particular, the Electricity Authority does not provide views on the merits of particular generation investments.

Transmission Investment

The Electricity Authority is also responsible for determining the grid reliability standards. Transpower is responsible for preparing grid upgrade plans based on the grid reliability standards and must submit them to the Commerce Commission for approval.

On 1 November 2010, the Commerce Commission replaced the Electricity Commission as the body required to approve transmission investments. Until it has developed its own investment test (called the “input methodology”) for evaluating Transpower capital expenditure proposals, the Commerce Commission must apply the grid investment test to each grid upgrade plan proposal as it appears in the EGRs. If the proposal meets the criteria specified therein, the Commerce Commission will approve the project and Transpower is entitled to recover the costs of the investment from designated transmission customers in accordance with the transmission pricing methodology specified in Schedule 12.4 of the initial Code (which is unchanged from the method specified in the Rules).

Transmission Pricing Methodology

The transmission pricing methodology (TPM) is used by Transpower to recover the full costs of approved expenditure (the “revenue requirement”) from designated transmission customers (ie grid-connected parties). The TPM is prepared by Transpower pursuant to TPM Guidelines provided by the Electricity Authority.

Under the current TPM the revenue requirement is separately calculated for the AC connection, AC interconnection, and the HVDC assets. AC connection assets are deemed to directly benefit one or a small group of transmission customers and costs are allocated according to the relative share of use of the assets. Those AC assets that are not deemed to be connection assets benefit all transmission customers and are referred to as interconnection assets. The revenue requirement for interconnection assets is allocated to all transmission customers according to a calculation of the relative share of the use of those assets. The revenue requirement for the HVDC assets is allocated to generators in the South Island according to a calculation of the relative share of the use of the HVDC.

The Electricity Authority is currently reviewing the TPM with a possible view to issuing new TPM Guidelines to Transpower. Any change to the TPM is unlikely to be implemented prior to April 2013.

62 The Act requires the Commerce Commission to develop its own investment test (called the “input methodology”) for evaluating Transpower’s capital expenditure proposals by 1 October 2011.
63 The grid investment test is specified in rule 4 in schedule F4 of part F of the EGRs.
The transmission costs associated with CHWF will depend on the extent of the transmission assets required to connect the wind farm to the grid, the designation of the assets concerned (ie whether they are deemed to be connection or interconnection assets), and the output of the wind farm.
Appendix 3. CHWF Simulation Analysis

This appendix describes the analysis undertaken by Concept in order to determine the likely market impacts of CHWF, how it will fit into the local transmission infrastructure, and how it will impact upon the operation of the national power system.

Simulation of CHWF

In order to explore these issues Concept has simulated the output from CHWF and how it might change the flow of electricity through the North Island transmission system. This analysis has been undertaken using half hourly data that has been synthesised by Aurecon New Zealand using wind speed readings at the CHWF site64 and by applying the TAO modelling framework65 developed by Concept in 2007. TAO is a model of the New Zealand electricity system that simulates the dispatch of generation sources to meet demand given available transmission capacities and transmission losses, fuel costs, generation plant availability, hydrological variation, and wind flow variation. Figure 29 on the following page provides a schematic representation of the transmission component of the model.

The TAO model allows the simulation of electricity market outcomes over the long-term for different development scenarios. In particular, the model is capable of simulating the full range of market outcomes while taking into account variations in hydrological inflows. TAO breaks down the transmission system into 18 regions allowing demand and supply in each region and flows between the regions to be simulated. Electricity prices can be determined and forecast for each of the 18 regions.

Note that we have assumed for modelling purposes that electricity from CHWF will flow into the transmission grid at Bunnythorpe.

The approach taken has been to choose the year 201666 and to simulate two scenarios – one without CHWF operating and one with CHWF operating, and to investigate the possible differences in electricity flows through the network and possible differences in transmission losses and location-based spot prices. In order to make the two scenarios realistic we have deferred some new generation projects in the “with CHWF” scenario such that the two scenarios have similar capacity and energy margins and a similar balance between supply and demand.

This analysis should not be regarded as conclusive or definitive about likely electricity market outcomes. In particular, it is noted that any differences in outcomes between the “without CHWF” and the “with CHWF” scenarios is sensitive to the choice of other new power stations to be deferred in the “with CHWF” scenario. Nevertheless, the results are considered to be illustrative of the likely impact of CHWF on operation of the New Zealand electricity market.

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64 Wind Resource and Energy Production – Castle Hill Wind Farm; Aurecon New Zealand Limited
65 TAO stands for “Transmission Augmentation and Optimisation”
66 The year 2016 was chosen because this was considered to be an indicative early year in which the CHWF could be fully operational
Figure 29: TAO Model Schematic

Source: Concept Consulting Group
The key assumptions made for the analysis are set out in Table 7:

**Table 7: Key assumptions for CHWF Simulation**

<table>
<thead>
<tr>
<th>Key assumption</th>
<th>Without CHWF</th>
<th>With CHWF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity demand</td>
<td>Mean forecast from 2010 SOO</td>
<td>Mean forecast from 2010 SOO</td>
</tr>
</tbody>
</table>
| Generation development scenario       | SOO “Sustainable Path” Scenario – a carbon charge and relatively high gas prices lead to a focus on renewable projects for new development | SOO “Sustainable Path” Scenario – modified by deferring the following projects:  
  - Wairau Hydro (SI) 73 MW  
  - Central Wind (NI) 120 MW  
  - Kaiwera Downs Wind (SI) 240 MW  
  - Te Mihi II Geothermal (NI) 60 MW |
| Fuel supply and price assumptions     | As per SOO “Sustainable Path” Scenario                                      | As per SOO “Sustainable Path” Scenario                                  |
| Castle Hill Wind Farm                 | Not applicable                                                               | 600 MW producing approximately 2,100 GWh per annum                      |
| Interisland HVDC transmission         | Upgraded to 1200 North/1000MW South                                          | Upgraded to 1200 North/1000MW South                                     |
| Huntly units 1-4                      | Three units available                                                       | Three units available                                                    |

*Source: Concept modelling assumptions*

Note, in particular, that the new power stations deferred in the “with CHWF” scenario include a mix of hydro, wind and geothermal power stations, with 180 MW deferred in the North Island and 313 MW deferred in the South Island.

**Indicative generation dispatch in 2016**

Figure 30 and Figure 31 on the following two pages illustrate how generation would be dispatched to fill two typical daily load duration curves in 2016, both with and without CHWF as part of the supply system. The days chosen are a typical summer day and a typical winter day.

The figures highlight that electricity received from the South Island via the HVDC transmission, geothermal, and wind tend to operate continuously across the day, while hydro and thermal electricity tend to be used to be used to supply the balance of demand, varying output as necessary. Note the large increase in thermal production during the winter when demand is high and hydro inflows tend to be low.

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67 A daily load duration curve stacks each time period into a sequence that runs from highest demand to lowest demand rather than in chronological order.
Figure 30: North Island Load Duration Curve without CHWF (2016)

Summer day at top and winter day at bottom
For the case with CHWF illustrated in Figure 31 there are several features worth noting as follows:

- The material increase in wind generation resulting from the addition of CHWF;
• A possible increase in the effective variability of the contribution from wind, resulting in hydro generation potentially needing to vary output more significantly;

• The possibility that the combination of high wind output and low summer demand could create situations where the need for North Island hydro output is very low.

Although it is unwise to draw strong conclusions from these snapshot daily load curves, they usefully illustrate the possible impacts of increasing contributions from wind farms in the North Island.