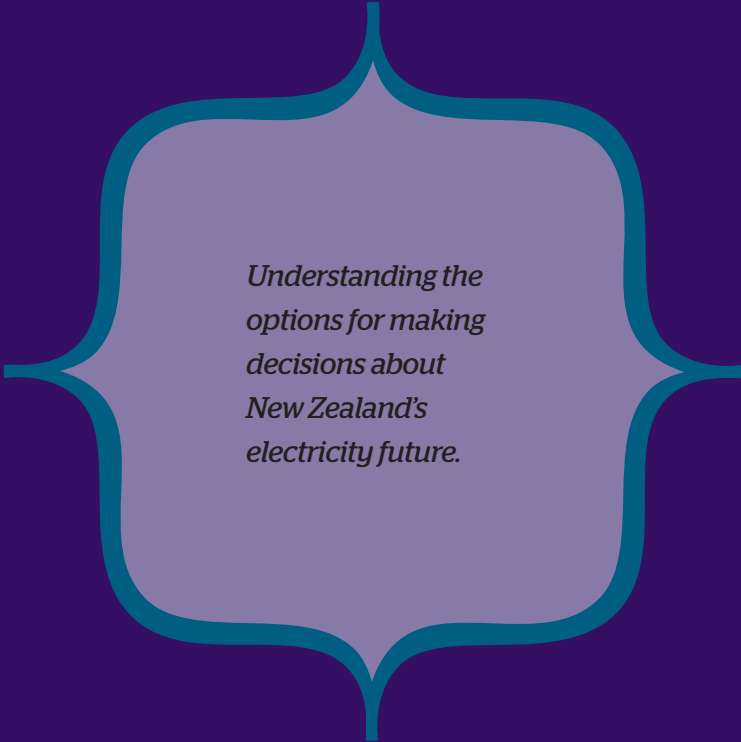


OPTIONS CHOICES DECISIONS

2009 Update



*Understanding the
options for making
decisions about
New Zealand's
electricity future.*

Disclaimer

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Table of contents

1	Introduction.....	1	4.4	The wholesale market design and performance	7	5.1.5	Coal.....	16
2	Recent events in the wholesale electricity sector	2	4.4.1	Wholesale market performance on new generation investment.....	8	5.1.6	Coal with carbon capture and storage	16
3	Executive summary.....	4	4.4.2	Wholesale market performance in dry-years	9	5.1.7	Nuclear	17
4	New Zealand's wholesale electricity sector	6				5.1.8	Other technologies.....	17
4.1	A brief overview of the New Zealand electricity industry	6	5	New Zealand's generation options.....	11	5.2	The likely mix of New Zealand's future generation options.....	17
4.2	Characteristics of New Zealand's wholesale generation sector	6	5.1	An overview of new generation economics and issues.....	12	5.3	Transmission	17
4.3	Electricity demand	6	5.1.1	Gas generation.....	12	5.4	Resource Management Act 1991 (RMA).....	18
			5.1.2	Wind generation.....	14	6	Glossary	19
			5.1.3	Geothermal generation.....	15	7	Bibliography	21
			5.1.4	Hydro generation.....	15			

1 Introduction

In 2006 Meridian published “OptionsChoicesDecisions: Understanding the options for making decisions about New Zealand’s electricity future” (Choices). The purpose of this document was to provide an objective perspective on the issues facing the industry and possible futures for the New Zealand wholesale electricity market. Choices was Meridian’s contribution to providing quality information needed for making good decisions in the sector.

This document updates some of the key parts of Choices in light of major energy sector developments over the past two years. The paper provides an updated view of the project economics of new generation options for New Zealand. We also discuss the performance of the wholesale market over its twelve year history.

Like the original Choices report, we hope this update is a valuable input into everyone’s understanding of the issues facing New Zealand’s wholesale electricity sector.

See the 2006 Choices publication for a fuller review of the technology options covered in brief in this report. The 2006 report also covers in detail demand side options for meeting electricity demand growth, including energy efficiency and micro generation. The report is available on Meridian’s website: www.meridianenergy.co.nz/AboutUs/Reports/

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In the two years since we published Choices, New Zealand's wholesale electricity market has been affected by a number of significant events.

In 2008
there was a very dry winter coupled with two major, unplanned plant outages – the decommissioning of the HVDC Pole 1¹ and of the 300 MW New Plymouth Power Station. The combination of these events led to significant strain on the system over the winter period. The events sharply focused industry and political attention on electricity security of supply.

In November 2008 a transformer failed

at New Zealand Aluminium Smelters Ltd (NZAS) at Tiwai Point, near Bluff, leading to reduced production. The smelter usually comprises some 15 percent of New Zealand's total electricity consumption. The reduced production has removed on average 194 MW of demand from the system. The operators of the smelter have not stated a date for resumption.

¹ The HVDC transmission link transports power between the North and South Islands. It includes two converter poles that use distinct conversion technologies. Pole 1, which uses mercury arc valve conversion technology, was commissioned in 1965. It was scheduled to be upgraded in 2012 and was expected to be in service until that date. However, in September 2007 Transpower stood Pole 1 down following analysis into the risks that the aging technology posed. This reduced the overall capacity of the HVDC link from 1000 MW to a reserve constrained 500 MW.

² New Zealand Government (2007). New Zealand energy strategy to 2050 – powering our future. Sourced from www.med.govt.nz/templates/MultipageDocumentTOC_31948.aspx

The previous Government released

its National Energy Strategy² in October 2007.

The Strategy has a target for renewable electricity generation to meet 90 per cent of New Zealand's electricity needs by 2025. The recently elected Government has flagged that it will revise this strategy.

OIL PRICE VOLATILITY

has affected costs across the economy, including new and existing generation plant costs.

Oil prices peaked in July 2008 at US \$144 a barrel, but have since fallen to below US \$50.

Domestic and global economies are experiencing significant turmoil.

This was driven initially by the US credit crisis. Many economies have subsequently slipped into recession. The New Zealand economy has been in recession since the beginning of 2008. The full implications of this recession on New Zealand's energy sector are currently unclear. Growth in electricity demand has already slowed and is likely to remain soft over the short term. A lower New Zealand dollar has resulted in higher costs for infrastructure projects with imported components.

CO₂e

There is greater uncertainty around the carbon policy environment, and the implications for investment decisions.

The climate science has firmed in both certainty and severity in the long term.

However, carbon markets are still emerging and are displaying significant price volatility.

This volatility has increased because of the global economic slowdown. The newly elected Government's decision to review New Zealand's Emissions Trading Scheme (ETS) has added to this uncertain environment.

Given these changes it is timely to provide an updated view of New Zealand's wholesale electricity market. We have sourced our analysis of the wholesale electricity sector from in-house expertise and experience, and from a range of external sources.

In 2006, Choices examined the issues facing New Zealand's electricity industry and their implications for the wholesale electricity market going forward. Since that time, the market has been affected by a number of significant events. This document updates the discussion in Choices in light of these developments. It comments on particular issues that have emerged since Choices was published.

Over the last two decades, demand has increased by around two percent per annum. The level of demand has plateaued in recent times following the downturn in both the domestic and global economies. However, we expect that New Zealand's demand for electricity will continue to grow over the medium to longer term in tandem with growth in the New Zealand economy and population. This demand growth will occur even given improvements in energy efficiency. New generation plants will be required to meet this increased demand and to replace plants that will be decommissioned over this period.

New generation capacity has exceeded electricity demand growth since the market's inception in 1996, increasing at around 1,250 GWh per annum. This new investment covers a range of technologies, including renewable, co-generation and thermal generation plants. For the period to 2011, another 3,000 GWh of generation is already committed. Beyond 2011, there is a large range of potential options; projects totalling some 48,000 GWh have been publicly announced while no doubt there are many others that remain confidential.

Despite this track record of continued investment in generation capacity, some commentators have expressed concern that investment may be insufficient to meet New Zealand's electricity needs. This commentary has been particularly vocal during dry-year periods, which in recent times have occurred in 2001, 2005 and 2008 (the last period was exacerbated by the unexpected decommissioning of the New Plymouth Power Station and Pole 1 of the HVDC).

New Zealand's hydro dominated system delivers comparatively low cost, low emissions electricity using a "fuel" mix that is largely renewable and predominantly from domestic sources. However, the limitation of this form of system is that sometimes rain does not fall when it is required. Along with demand response, flexible peaking plant is likely to be the lowest cost approach for addressing this variability.

The mix of investment in electricity generation plant is driven primarily by economic considerations. Other broader objectives, such as social policy outcomes, may influence investment



decisions through the regulatory environment. A mix of diverse generation forms is important for the proper operation of the New Zealand electricity system. These various generation forms have different attributes and perform complementary roles.

From an economic perspective, project options are commercially filtered according to their long-run marginal cost. Essentially, the next project that should proceed should be the lowest cost project amongst the possible options. Our analysis shows that, on this basis, a mix of generation technologies may be commissioned over the medium to long term. The factors that will drive this mix include the price and availability of gas and the regulatory environment – including the carbon regime that is implemented and the ability of various projects to gain appropriate resource consents.

This review finds that, given current project economics and New Zealand's gas supply outlook, on a least-cost options basis we expect a greater share of renewable projects to proceed relative to thermal projects using gas. In the near term these are likely to be wind and geothermal projects.

Other key factors that influence new generation investment decisions include transmission investment and the Resource Management Act 1991 (RMA) process. Adequate and timely transmission investment is critical to addressing concerns about security of supply and to enable the long term delivery of the most economic supply options. The RMA process can place a high hurdle and bottleneck on large infrastructure projects – significantly impacting on project economics and viability. The Government's recently announced package of RMA reform amendments will hopefully streamline the process for consenting future energy projects.

4 New Zealand's wholesale electricity sector

4.1 A brief overview of the New Zealand electricity industry

A market structure for electricity generation and retail has been in place since 1996.

In 1987 the New Zealand Electricity Department (NZED) was fully corporatised as a state-owned enterprise (SOE) under the State Owned Enterprises Act 1986, becoming the Electricity Corporation of New Zealand (ECNZ). From these beginnings, the first step toward the current electricity market structure was made in 1996 with the government's split of Contact Energy from ECNZ. The current structure was established in 1999 when ECNZ was further separated into the three SOEs, Meridian Energy, Genesis Energy, and Mighty River Power. In the same year Contact Energy was privatised.

Transpower was split out of ECNZ in 1994 as a separate SOE to perform the functions of transmission asset owner and system operator. The industry specific regulator, the Electricity Commission, was established in 2003, after industry attempts at self regulation failed.

Today there are six major generation organisations. Meridian generates around 13,500 GWh in an average year with 2,600 MW of installed generation (2,450 MW of hydro and 150 MW of wind). Meridian currently has around 30 percent market share by production volume. Contact has the next largest share at 26 percent, followed by Genesis at 19 percent, Mighty River Power at 14 percent, TrustPower at 5 percent and Todd Energy at 2 percent.

4.2 Characteristics of New Zealand's wholesale generation sector

The New Zealand wholesale generation sector is based around hydro generation, complemented by significant gas and coal thermal generation.

Historically, electricity demand growth has been met from a diverse range of fuel sources with a heavy emphasis on renewables – particularly hydro energy. Around 70 percent of New Zealand's electricity is produced from renewable resources. Hydro energy has provided New Zealand with comparatively low cost, low carbon emission electricity. Because of its high capital and low operating costs hydro generation is ideally suited to operating as baseload plant.

This emphasis on hydro generation has led to New Zealand being susceptible to weather-related risk, especially during periods where there are low hydrological inflows into hydro lakes (these periods are often referred to as "dry-years" even though the low inflows may only occur over a few months). New Zealand's hydro storage capacity is relatively limited, at around 3,600 GWh (equivalent to around 10 weeks of winter electricity demand).

Historically, this risk has been managed through the construction of "hydro-firming" thermal plant (for example, Huntly Power Station). This form of plant is designed to be operated more flexibly: when inflows reduce, firming plants operate to "take up the slack" or firm supply. In this manner, the portfolio of generation plants is used to deliver energy to meet demand, across a broad range of hydrological inflow sequences. The inter-island HVDC transmission cable also plays an important role, making thermal North Island generation available to the South Island in times of low hydro storage. The recent decommissioning of the HVDC Pole 1 has reduced the ability of the system to perform in this manner (see section 5.3 Transmission).

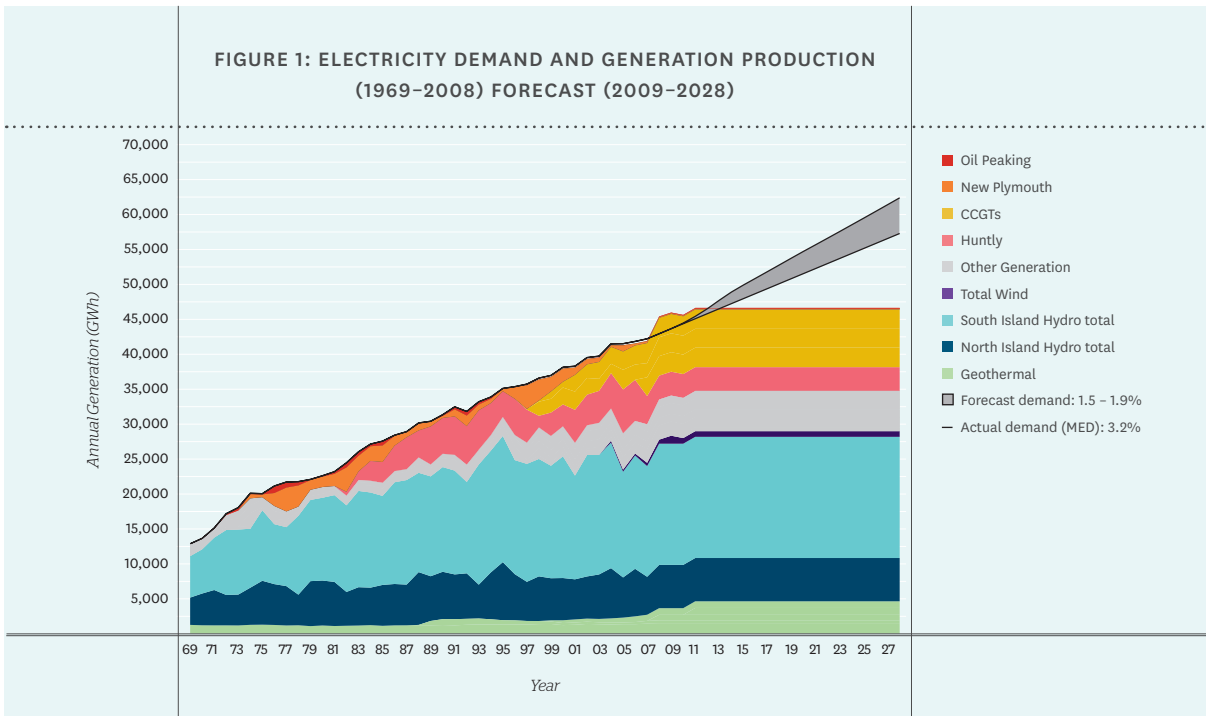
Some thermal plants are used in a more baseload role. For instance, in the past, the combined cycle gas turbine (CCGT) plants Otahuhu B and Taranaki Combined Cycle (TCC) have operated at baseload, fuelled by low cost Maui Contract gas that had firm take-or-pay obligations. Following the Maui redetermination in 2003, Huntly Power Station was operated in a baseload capacity for several years using coal, as production from these gas plants was eased back. In June 2007 Genesis Energy commissioned the 400 MW e3p CCGT plant at Huntly. The plant is run as baseload generation allowing the Huntly power station to revert back to a "hydro-firming" role.

New open-cycle plants that fill a hydro-firming role have been commissioned, including Mighty River Power's 45 MW open cycle gas turbine (OCGT) extension to its Southdown gas plant and Genesis Energy's 50 MW OCGT gas plant at Huntly. We expand on this hydro-firming issue further in section 4.4.2 of this paper which examines security of supply and dry-year issues.

4.3 Electricity demand

We expect that electricity demand will continue to increase over the medium to long term, even given major improvements in energy efficiency. Significant new generation investment will be required to meet this demand.

New Zealand's electricity demand has grown consistently over the last 20 years. Electricity generation has increased from approximately 29 TWh in 1987 to 42 TWh in 2007, an average growth rate of two percent per annum. Peak demand, which occurs in winter, is around 7 GW (this includes all line losses and embedded generation).



Electricity demand growth has been more modest over the last five years. Most recently this change in growth has been caused by the global economic recession, the reduced production at the NZAS smelter caused by a transformer failure and the 2008 dry-winter episode. It is unclear how electricity demand will move over the next few years, given the uncertainties pervading the macro economy at the present time.

Over the medium to longer term, we expect that New Zealand’s electricity demand will grow in tandem with both longer term economic and population growth. This growth is likely even given significant improvements in energy efficiency. Our base forecast is shown in Figure 1. This additional demand will require new generation to be installed, that produces in the order of 500–900 GWh per annum. This is roughly equivalent to an additional 70–100 MW of baseload electricity capacity each year.

There could be demand events that may alter the forecast shown in Figure 1.

The graph shows that historical demand growth has not been uniform: various factors have led to growth being below or above the long term trend for several years. The impact of the current economic downturn is one example of such an event. A major industrial business deciding to leave New Zealand is another example. In this latter example, overall demand could be flat or even fall for a period (depending on the nature of the business). Notwithstanding these events, demand growth is likely to remain robust over the longer term.

4.4 The wholesale market design and performance

The wholesale electricity market has performed largely as expected when measured against the design criteria from the early 1990s. In particular, it has signalled both the need for new generation investment and also the need for consumption to adjust in times of scarcity.

In New Zealand the buying and selling of wholesale electricity is done via a “pool”, where electricity generators offer electricity to the market and retailers bid to buy the electricity at prices set half-hourly. The market is an “energy only” market – participants are paid only for their actual energy production. The market has been designed to be cost reflective over the long run; this means that new generation investment is built in response to projected market prices over the longer term.

The wholesale market was set up in 1996 to achieve three main goals:

- To signal the need for new investment through long-run prices
- To allow the government to exit the planning and management of the system, and also enable it to avoid underwriting all new generation
- To signal the scarcity of generation and the need to adjust consumption in dry-years through short-run prices.

We discuss the first two goals in the next section of the paper, which examines the market's performance on new investment. The section that follows, 4.4.2, examines the market's performance in relation to dry-year issues.

4.4.1 Wholesale market performance on new generation investment

Investment signals for new generation are being acted upon. There is a depth of options, both committed for construction or under investigation in both the near term and the long term. New generation production capacity has exceeded demand growth since 1996.

Recently there has been debate over the effectiveness of the wholesale electricity market to deliver timely investment. This debate was heightened by the conditions experienced in winter 2008; we address issues around security of supply in the next section of this paper. While this debate is likely to continue, the fact is that significant generation capacity has

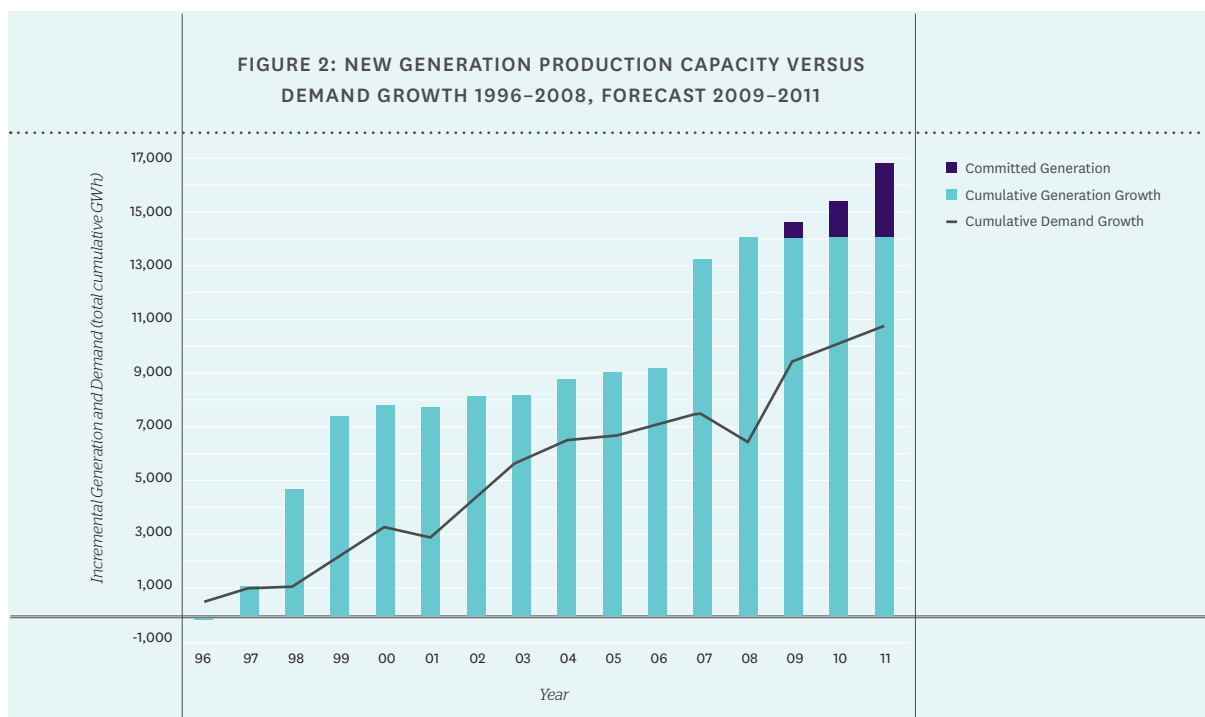
been added to the system since the market began operation in 1996. Figure 2 sets out annual cumulative generation production capacity in GWh – shown by the bars (this includes decommissioned generation capacity). Figure 2 also charts new cumulative demand growth since 1996, the black line, also measured in GWh.

Figure 2 shows that additional generation production has been commissioned in response to demand growth. As expected, the margin between new generation production and additional demand tightened in the early 2000s in response to a period of capacity over-supply. However, the projected margin of generation production over demand in 2009 is expected to be similar to the margin experienced in the late 1990s. This fluctuation is a natural consequence of the lumpy nature of new generation plant being added to the system. If the data in Figure 2 is averaged over the period since 1996, around 1,250 GWh of new generation production has been added each year. This additional production is well ahead of average

demand growth over the period (around 600–700 GWh per year) even after the energy removed by decommissioned plant is accounted for.

Over the same period, new installed capacity has also exceeded peak load growth. On average, around 200 MW of new generation has been added per year (while decommissioned plant has totalled some 1,250 MW over the period or 100 MW per year). This additional capacity has exceeded the growth in peak load, which has been around 90 MW per year. From a generation perspective the peak capacity margin of the system has actually improved. However, access to peak generation capacity has become more constrained by a lack of adequate transmission capacity (see section 5.3 Transmission).

This additional generation capacity has come from a number of new generation plants. These plants cover a range of generation technologies, “fuelled” by various energy sources including gas, wind, hydro and geothermal. Of the 16,000 GWh total new generation added



to the system since 1996, 9,400 GWh has been from thermal technologies, 1,600 GWh has been from co-generation technologies, and 5,000 GWh has been from renewable technologies. These generation investments have been implemented by all the six major generators as well as several merchant generators and lines companies.

We project continued significant investment in new generation options out until at least 2011. Around 3,000 GWh of this new generation is already committed. Much of this investment is in renewable generation. Multiple options including geothermal, wind, hydro and thermal peaking plant are being pursued by various generation companies. The project locations are spread across New Zealand.

Beyond 2011 there is a large range of potential generation options – particularly in the renewable area – that can meet New Zealand’s demand growth for at least the next 20–30 years at prices between 7–10c/kWh. We have identified:

- Over 18,000 GWh of wind options publicly announced and under investigation
- Over 10,000 GWh of remaining hydro potential including over 3,000 GWh of publicly announced projects
- Over 10,000 GWh of remaining geothermal options, including more than 6,000 GWh of publicly announced projects
- Over 10,000 GWh of thermal projects that have been publicly discussed.

Peak generation options are also actively being pursued, showing that the industry is responding to market signals for non-baseload generation. Some 300 MW of capacity (the Huntly P40 unit, the extension to Southdown and the Stratford Peaking plant) is either already commissioned or committed.

This depth of generation options suggests that the market has signalled the need for new investment through long-run prices and investors have responded. In general, investment in new generation to date has been on a least-cost options basis, with a total capital spend of over \$4 billion. The current market has functioned so that the New Zealand government no longer needs to take on the inherent investment risks involved with developing new generation options (the government’s decisions to underwrite the fuel supply for Genesis Energy’s e3p CCGT plant and to purchase the Whirinaki reserve energy plant are recent examples of where it has invested in the sector).

Although generation investment has been made in a timely and efficient manner, transmission investment over much of the period that the market has been in operation (particularly the period until the establishment of the Electricity Commission) has been limited. This is due to:

- A previous view that new generation would be located close to demand, reducing the need for transmission infrastructure
- A market construct that meant Transpower could not be certain it could earn an economic return on its transmission investment.

This lack of investment has led to insufficient transmission capacity in some regions and an ageing infrastructure. A lack of transmission capacity has led to constraints in various regions, causing periods of price separation. The formation of the Electricity Commission in 2003 addressed several of the major issues and significant new transmission investment is planned. However, the approval process for transmission investment can be protracted. Transmission issues are discussed more fully in section 5.3.

4.4.2 Wholesale market performance in dry-years

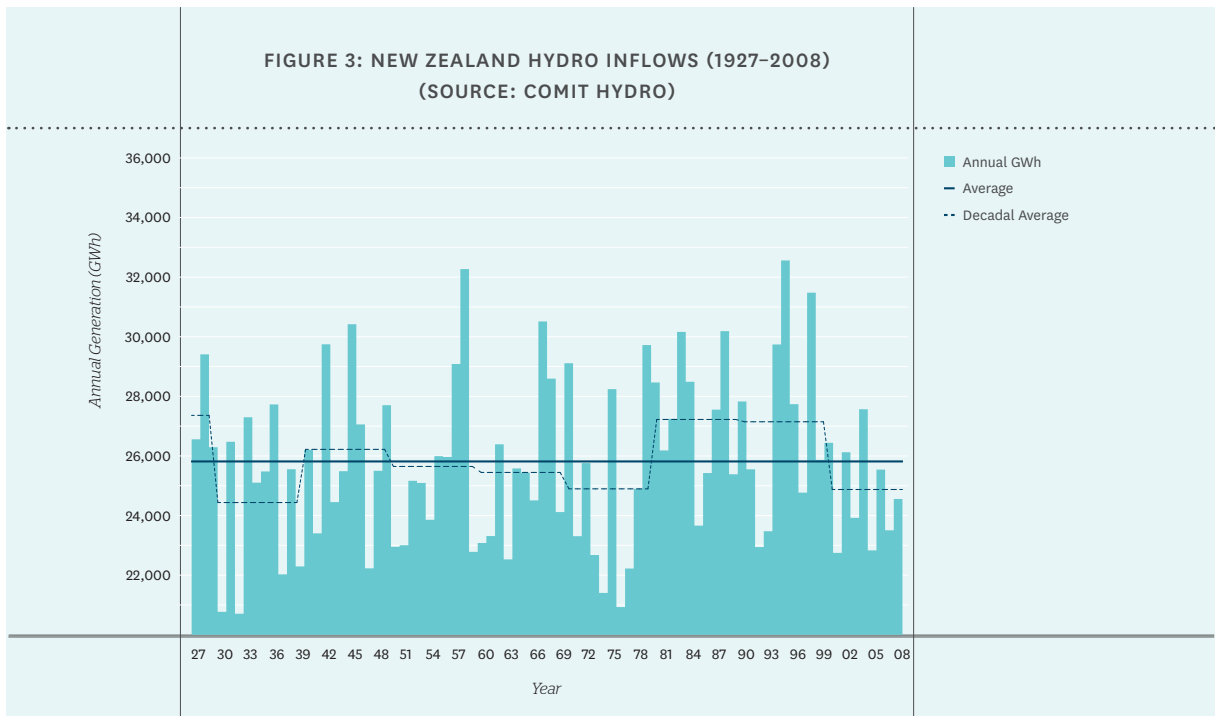
This decade is close to the driest on hydrological record. The current market structure has functioned to signal scarcity of generation, and the market has responded, managing the system under times of severe scarcity with no hydro-shortage-related brown-outs or black-outs occurring.

New Zealand’s main electricity production fuel – hydro inflows – is inherently volatile. Figure 3 on page 10 shows total New Zealand annual hydro inflows from 1927–2008 in GWh.

Figure 3 also shows long-run average hydro inflows (around 25,800 GWh per annum), represented by the solid dark blue line, and decadal average hydro inflows, shown by the dashed blue line. New Zealand’s significant annual hydrological volatility is evident in this figure.

This current decade, particularly the period 2000–2008, is close to the driest decade on record (in over 80 years of data). Dry-year episodes (sustained periods of low hydro inflows) have occurred in 2001, 2005 and 2008 (tight supply conditions in 2003 were caused mainly by an unexpectedly low Maui gas redetermination which left thermal generation plants short of fuel). Hydro inflows over this decade are five percent below the long-run average. This is equivalent to a reduction in hydro production of around 1,000 GWh each year (by comparison a CCGT produces around 3,000 GWh annually).

Although there has been a run of poor hydrological events over the last decade, supply has continued to meet demand, even under times of significant “fuel” scarcity. Like other markets, as the cost of supply has increased, the wholesale price has risen reflecting these scarcity conditions. Demand has responded to



these signals: in 2001, 2003, 2005 and 2008 demand reduced by 4–6 percent.

Importantly, there have been no hydro-shortage-related brown-outs or black-outs in the 12 years of market operation³. The continuation of electricity supply over this difficult period is in contrast with similar periods of low hydrology in the era of central control. For instance, in 1992 but also in 1957, 1958, 1973, 1974, 1976, 1977 and 1978, there were rolling brown-outs, leading to significant decreases in national economic output and growth.

New Zealand’s hydro dominated system delivers comparatively low cost, low emissions electricity using a “fuel” mix that is predominantly renewable and mostly from domestic sources. However, this exposes New Zealand to hydrological risk as rainfall is variable. Flexible thermal peaking plant is one solution to meet this variability.

The appropriate amount of flexible peaking plant involves a trade-off between the cost of investing in peaking plant and the cost of tight supply conditions (or the price that consumers are prepared to pay to avoid a given likelihood of a shortage). At one extreme, large amounts of capital could be invested for multiple peaking generation units. These plants would not often run. The costs of such a high level of insurance would be large, resulting in higher electricity prices. At the other extreme, limited investment in peaking plants would lead to increasing levels of infrequent but costly hydro-related shortage events. The cost and price associated with this investment would be lower but the likelihood of a shortage would be higher. The market has been delivering new peaking plant in response to price signals from the market, as noted earlier. The Electricity Commission plays an ongoing monitoring role, with annual reviews of the security of supply outlook including possible reserve energy needs.

Adding further baseload generation to the system is another option for safeguarding against dry-hydro years. This option presents similar issues to those associated with the building of more peaking plant. However, the cost of this option would be substantially larger since baseload plant, by its very nature, is designed to operate almost continuously. In many periods there would be “too much” generation capacity implying significant economic inefficiency.

The balance of New Zealand’s generation mix is expected to change over time with more diverse forms of new generation, including geothermal and wind plants, being added to the system. This generation diversity will help to mitigate dry-year risk.

³ In a brown-out or black-out situation there is a disjoint between available supply and demand; there are customers who demand electricity but are unable to receive it. Contrast this with how markets function typically, where prices adjust so that there is a balance between the quantity of a product that is supplied and the amount that customers demand.

5 New Zealand's generation options

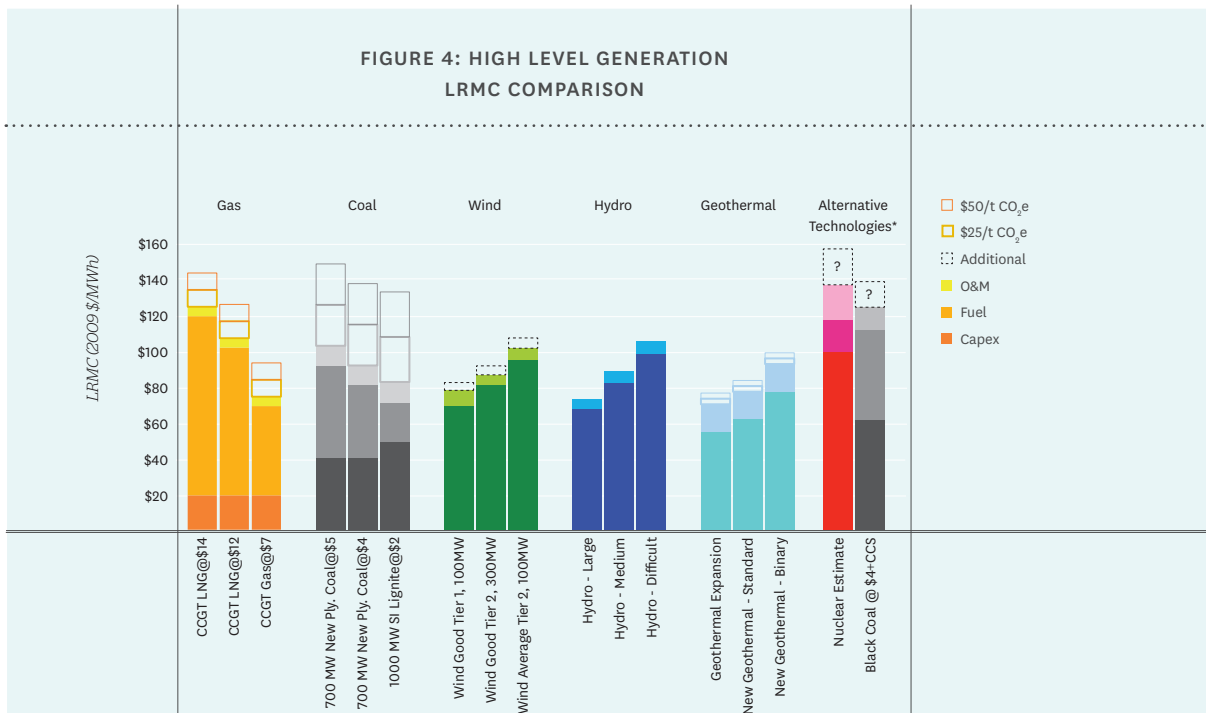
New large scale electricity generation projects will be required to meet New Zealand's future electricity needs⁴.

As demand growth continues to rise over the long term New Zealand will require new investment in electricity generation. The mix of investment in electricity generation plant is driven primarily by economic considerations. Other broader objectives, such as social policy outcomes, may influence generation investment decisions through the regulatory environment.

It is important to note that a mix of diverse generation forms is essential to the proper functioning of the New Zealand wholesale sector. The various forms of generation have different attributes and perform complementary roles. A diverse range of generation types helps to limit the risks inherent in each form. From an economic perspective the projects that should proceed are those with the lowest long-run marginal cost (LRMC)⁵. In the discussion that follows, we consider the LRMC of various generic

generation projects to understand the possible mix of future electricity generation in New Zealand.

The estimated LRMC of various generic generation projects is summarised in Figure 4. In this report we use the (levelised) unit cost of a project as the proxy for the project's LRMC. A nine percent post-tax nominal discount rate has been used.



The chart shows LRMC or unit cost estimates of various generic project types: combined cycle gas turbines, coal, wind, hydro, geothermal, nuclear and coal with carbon capture sequestration respectively. The generic projects presented illustrate how LRMC varies within and between each generation form.

The bottom part of each bar represents the fixed cost portion of LRMC (i.e. capital costs); the coloured parts above this represent the variable cost portion (i.e. fuel and operations and maintenance costs). The remaining transparent portions on the gas, coal and geothermal bars identify the impact on LRMC of various carbon regime scenarios (specifically \$25 and \$50/t CO₂e carbon price scenarios as proxies for the impact of possible carbon policies). The transparent portions with a dashed line represent potential additional costs of wind projects (system costs associated with managing intermittency), nuclear (waste storage/clean-up) and coal with carbon capture (carbon storage). Note: these are point estimates based on a long-run NZ dollar – so the LRMC of projects with high levels of imported components will vary around these as the dollar fluctuates.

The selected generic projects for each generation form show the variability between a “prime” project at one extreme (which has a lower LRMC) and an “average” project (which has a higher LRMC) at the other extreme. This variability is driven by location-specific issues for the various generation options and, in the case of thermal projects, fuel costs. The impact of HVDC charges has not been included in these LRMC estimates. Under the current transmission pricing methodology this charge adds up to \$10/MWh to the LRMC of South Island opportunities.

⁴ Note we do not cover demand side options in this paper. These options will also meet a share of New Zealand's future demand growth; this topic was covered in detail in Choices 2006.

⁵ The LRMC of a new power station is the long-run marginal cost of producing electricity from the plant. LRMC includes short-run marginal costs (e.g. fuel costs) plus costs which are fixed in the short run but marginal in the long run, in particular the capital investment cost of the station. In this report we have taken the LRMC of a plant to be equal to its (levelised) unit cost.

* We do not show other alternatives, such as solar PV and marine, in this chart as these technologies have unit costs which are significantly greater than \$160/MWh.

5.1 An overview of new generation economics and issues

The relativities in cost between new generation projects suggest that there is the potential for a mix of new generation forms in the future.

Figure 4 shows that the LRM spread within generation forms is generally greater than the variation among most forms (excluding nuclear and coal with carbon capture and storage (CCS) which both have significantly higher costs). This overlap implies that there is the potential for a mix of new generation forms in the future. The proportions of the various generation technologies will depend on various factors. The factors with the greatest influence include gas availability and price. The nature of the regulatory environment, including the carbon regime and RMA, is another key factor.

Another key point from the chart is that the make-up of LRM differs between thermal and renewable projects. In the case of the thermal technologies, coal and gas, the LRM of the projects is primarily driven by operating costs – particularly the costs of fuel. In contrast, the costs of all the renewables options are weighted much more towards fixed capital costs, typically 80–95 percent of LRM. This means that higher gas prices will unlock a predominantly renewables future, whereas lower gas prices will reduce the number of renewables projects that will proceed. Additionally a price on carbon will also raise the cost of thermal technologies relative to renewable technologies. The chart shows that a carbon price of NZ \$25/t CO₂e would make most coal projects uneconomic. With carbon prices for secondary certified emission reduction (CER) units trading at around €10/t CO₂e (or NZ \$25/t CO₂e at 0.40 NZD/EUR) at the time of writing, renewable

generation options are likely to dominate if New Zealand is exposed to an internationally linked carbon mechanism.

The relative economics of various potential generation projects is dependent on individual project characteristics and fuel costs. This next section discusses the factors that affect the LRMCs of each form of generation, as well as characteristics and issues associated with each generation type. See the 2006 Choices publication for a fuller review of the technology options covered in brief in this report.

Since Choices was published in 2006 the capital cost of all technologies has risen, increasing the LRMCs of all project options. This increase has particularly affected the LRMCs of renewables projects, because the cost structures of these projects have a higher fixed capital cost component. The increase in project capital costs has been driven mainly by rising commodity prices which increased significantly over the latter part of the decade up until 2008.

In recent times, these prices have fallen substantially with the global economic downturn. The New Zealand dollar has also depreciated against a number of currencies. There is still considerable volatility in both of these economic factors as well as many others. It is unclear how these factors will move over the next several months and what the net impact of these movements will have on various project LRMCs.

Acknowledging these short term economic fluctuations, we estimate that the LRMCs of new generation projects over the medium term could be around 10–20 percent higher than the figures we published in 2006. For example, we estimate that the LRM of the very best wind sites over this timeframe is around \$78/MWh, representing an increase of \$13/MWh over our 2006 estimate.

Figure 4, and the discussion that follows, reflect our current estimates of LRM over the medium term. As noted above, it is difficult to forecast where underlying cost drivers may trend in the current environment. An updated analysis of these drivers may be the subject of a further Choices update in due course.

5.1.1 Gas generation

Over the last few decades, gas has been the fuel of choice for thermal generation because of its comparatively low price and its lower emission profile relative to coal. New Zealand's future wholesale electricity price has tended to be shaped by the economics of new gas-fired plant.

Gas has been the primary fuel of the 1,000 MW Huntly Power Station, but as the Maui gas field has depleted, Huntly has increasingly switched to coal. Genesis Energy's new e3p 400 MW combined cycle gas turbine (CCGT) plant runs on gas. Gas is used to fuel Contact Energy's 367 MW TCC plant and its 380 MW Otahuhu B plant. It is also used in a range of smaller generation plants, including co-generation facilities. Gas generation accounts for around 18 percent of New Zealand's installed generation capacity. As discussed earlier, thermal generation plays an important role in the New Zealand system, balancing the inherent variability of hydro generation.

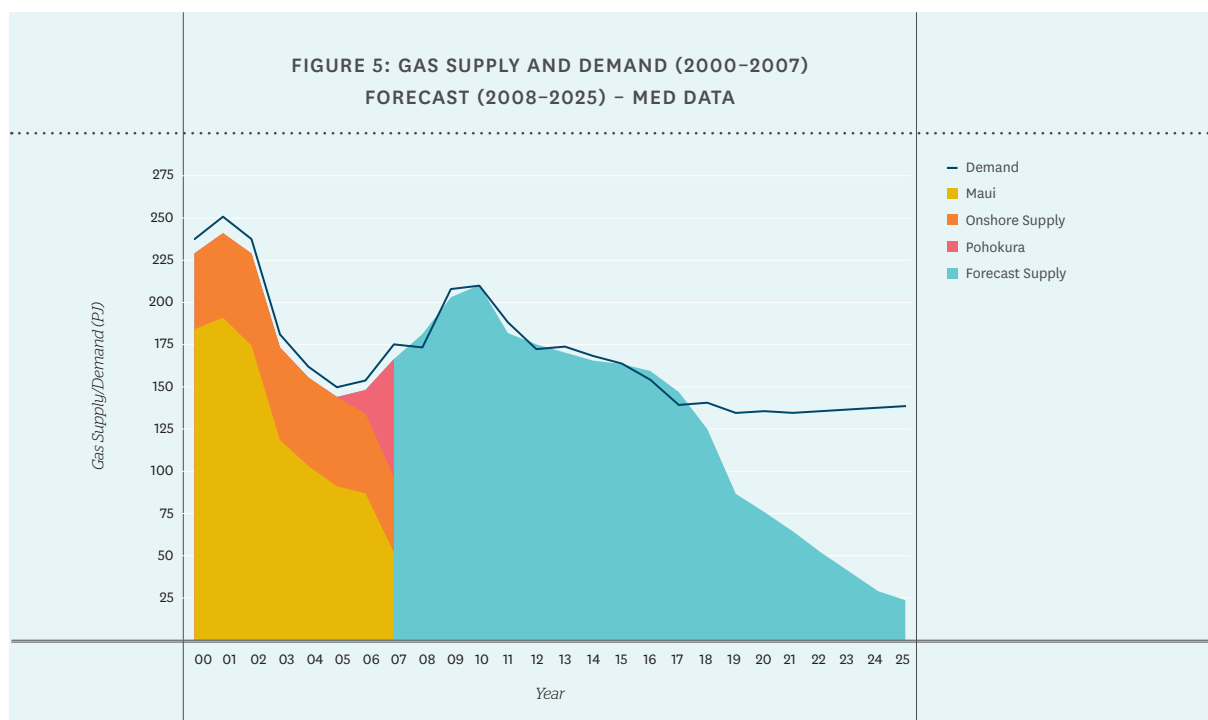
GAS – ISSUES

The major issue for the gas sector is the uncertain outlook for gas availability and supply to the electricity industry.

Figure 5 on page 13 (data sourced from the Ministry of Economic Development⁶) shows that additional gas will be required to meet existing demand by the second half of next decade. In the short to medium term the gas market is reasonably in balance.

⁶ Ministry of Economic Development (2009). Gas energy data. Sourced from www.med.govt.nz/templates/ContentTopicSummary_____21218.aspx

**FIGURE 5: GAS SUPPLY AND DEMAND (2000–2007)
FORECAST (2008–2025) – MED DATA**



Beyond 2010 the key issue for the gas market is whether sufficient additional reserves can be proved up to meet demand in the latter part of the decade. The MED’s “Gas exploration issues: brief to Infrastructure Ministers”⁷ notes that the gas exploration phase could take 5–10 years for offshore prospects, while the development phase could take a further 5–10 years. Onshore small discoveries could anywhere from 2–10 years for exploration and appraisal, with a further 1–4 years for development. These long lead times suggest that gas supply conditions could be tight in the medium term unless further gas is found soon.

Flexible gas supply is also difficult to obtain. Tight supply conditions have led to gas supply contracts having relatively inflexible “take-or-pay” arrangements. The smaller fields that are currently in production also have less flexibility in deliverability. Contact Energy has decided to use the depleted Ahuroa gas field, located in Taranaki, as a storage reservoir to provide it with some supply flexibility. This flexibility will enable Contact to

improve the operation of its gas peaking plant, by giving it the ability to bank gas to use when market prices are high.

Contact Energy currently holds consents to build two gas-fired CCGT stations. These are for the 400 MW Otahuhu C site (consented in 2001) and the Taranaki combined-cycle site, which is consented for a second 400 MW CCGT project (consented in 2002). Contact recently tested the market for long term gas supply and found that uncertainty on long term gas prices did not support the investment in a new 20-year CCGT plant.

GAS – ECONOMICS OF NEW GENERATION OPTIONS

The economics of CCGT plants are driven primarily by the gas price as delivered to the plant. Over time, this price will be set by the nature of future gas discoveries or the price of imported gas.

If a long term supply of domestic gas could be sourced at current market prices, around \$7/GJ, gas-fired plant is one of the more competitive generation

options, with an LRMC of approximately \$85/MWh (including \$25/t CO₂e carbon price). This is approximately the economics of the recently commissioned Genesis e3p CCGT plant. However, as Figure 5 shows, it is unclear whether there will be sufficient domestic gas reserves over the medium to long term to fuel a new, \$500 million gas plant over its life of around 30 years. The price of future domestic gas supply is also uncertain.

In the absence of local gas supplies, imported liquefied natural gas (LNG) is the only other option available to fire new baseload CCGT plant. LNG supplies are contractually indexed to international oil prices. It is expected that oil prices in the medium term will be around \$60–70 per barrel⁸. Together with a projected increase in demand for LNG over this period, this level of oil prices is likely to drive higher long-run LNG prices. The additional costs of LNG storage and gasification facilities required means that at a \$70 per barrel oil price, the price of gas supplied as LNG may be around \$12/GJ delivered to the station. A new CCGT

⁷ Ministry of Economic Development (2004). “Gas exploration issues: brief to Infrastructure Ministers”. Sourced from www.med.govt.nz/templates/MultipageDocumentTOC_15027.aspx.

⁸ International Energy Agency (2008). *World energy outlook 2008*. Paris: IEA.

plant running on LNG gas at this price is uneconomic, at least in the medium term. Importation of LNG in this price range only appears to be economic for re-firing existing gas-fired plant where the capital cost of that plant is already sunk.

If oil prices rise to \$100 per barrel, this LNG price will likely increase further to at least \$14/GJ. Delivered LNG prices at these levels imply a LRM for baseload CCGT of over \$130/MWh (including a \$25/t CO₂e price).

5.1.2 Wind generation

Wind generation is a relatively recent technology in New Zealand, having successfully made the transition from an alternative energy source to a cost competitive renewable generation technology. Wind is an intermittent source of generation; it is unlikely to ever totally replace other forms of generation such as thermal or hydro power stations. However, New Zealand has consistently strong wind conditions compared with most other countries⁹, so wind generation has the potential to be a significant part of New Zealand's future generation fleet.

There is currently 325 MW of installed wind capacity in the New Zealand power system, representing around four percent of New Zealand's total market. This small share is expected to grow over time, with another 180 MW currently under construction. There are over 5,000 MW of publicly announced wind projects under investigation by a range of investors.

WIND – ISSUES

An issue for wind generation is that its energy source is intermittent so production from this plant varies. Wind generation therefore needs to be balanced by other forms of generation. There has been debate about what impact wind generation might have on system costs.¹⁰ Meridian commissioned independent research by Professor Goran Strbac of the UK Imperial College to understand the possible system costs of wind in New Zealand.¹¹ The research found that due to its intermittency, wind generation plants will bring forward the need for additional system capacity and/or flexibility. But the research also found that the overall system cost of the capacity and flexibility required is relatively minor, due to New Zealand's large hydro asset base, and will not be significant for some time (until wind penetration reaches 15–20 percent, at least 10–15 years away). New Zealand's large hydro generation capacity, which is ideally suited to providing the flexibility to complement wind generation, places it in a strong position for future wind generation.

Another issue for wind is that local environmental issues (such as noise and visual concerns) need to be assessed and weighed up against the local and national benefits. New wind farms continue to face opposition at the consenting stage.

WIND – ECONOMICS

The relative economics of specific wind generation projects are driven by the local wind resource, the scale of the development, complexity of the site and supporting roading and transmission infrastructure. As such, the LRMCs of wind projects are highly site specific.

Apart from site characteristics, wind farm economics are also affected by economic conditions at the time of committal. Key factors include exchange rates, steel prices and international turbine demand.

Wind turbine costs have risen substantially, especially over the last three years. This has been due to a combination of increasing commodity prices and a large increase in demand for turbines. Being a capital intensive investment this increase has translated directly into increased headline costs for wind generation. Where wind turbine prices will go in the long run is something of an unknown. However, most commentators assess the recent situation as being essentially temporary in nature. Commodity prices have already fallen dramatically in recent times as the world has entered a recessionary phase. Over time, wind capital costs are expected to move to a new equilibrium point as commodity prices continue to adjust and manufacturers re-align their production facilities (especially in China) to service global demand.

The current "equilibrium" view of wind turbine prices suggest that the best tier 1¹² sites will cost nearly \$80/MWh with additional system costs contributing perhaps another \$5/MWh (when wind penetration levels have increased to 15–20 percent of total New Zealand energy supply). There are only a handful of these sites nationwide with a potential of around 2,000 GWh. On the same basis good tier 2¹³ sites are likely to cost around \$85/MWh with average tier 2 sites costing around \$100/MWh. Tier 2 sites are more plentiful, with over 6,000 GWh of good tier 2 sites and abundant average tier 2 sites available.

⁹ Good NZ wind farm sites such as the Tararua Ranges and Wellington can generate up to 88 percent of the time with capacity factors of between 44 and 48 percent. International average wind capacity factors are between 23 and 30 percent.

¹⁰ System costs are the additional costs that any specific technology imposes on the overall power system. System costs do not include the capital costs to construct generation plant. Examples of system costs are additional frequency keeping services that may be required to manage wind variability and additional instantaneous reserves costs to cover the risk of large thermal plant outages.

¹¹ Strbac, Goran et al. (2008). *The system impacts and costs of integrating wind power in New Zealand*. London: Imperial College.

¹² Wind speeds above 8.5 metres per second (m/s).

¹³ Wind speeds between 7.5–8.5 m/s.

5.1.3 Geothermal generation

New Zealand's history with geothermal generation development started in the 1950s with the commissioning of the Kawerau and Wairakei geothermal power stations. The discovery of the Maui gas field and the availability of hydro power slowed down geothermal development. However, in recent years the technology has experienced a renaissance as market conditions have tightened and gas supply has reduced. New Zealand has a large geothermal energy resource that can be harnessed to produce baseload renewable electricity at a competitive cost.

Today there is 485 MW of geothermal plant capacity in the system, representing around five percent of New Zealand's total generation market. Both Mighty River Power and Contact Energy are actively developing new geothermal options in the central North Island which are expected to add over 400 MW of new capacity in the next 2-3 years.

GEOTHERMAL – ISSUES

The main issue for geothermal development is the high upfront costs associated with proving the resource. Geothermal exploration wells cost millions of dollars to drill and have risk characteristics similar to oil exploration. This is why most current geothermal developments are on known proven fields. Geothermal generation may also be subject to field depletion, giving it a higher life-cycle risk than other renewable options. Geothermal generation is also location specific, with the principal known resource being located in the central North Island.

GEOTHERMAL – ECONOMICS

While the geothermal fuel resource is “free”, finding and maintaining the resource for the lifetime of the plant can be difficult and expensive. Sites and fields that have a proven track record are therefore more attractive than completely untested resources. Given this, a brownfields expansion of an existing project is typically the cheapest and most successful type of geothermal project. The Mokai extension project is an example of a brownfields expansion. These brownfields sites are possibly the cheapest of all of the new generation options with a LRMC estimated to be around \$70/MWh or less (with the possibility of additional costs (\$3-5/MWh) for any associated carbon emissions). However, such developments are limited largely to the eight key existing geothermal generation fields – up to about 2,500 GWh potential.

A new geothermal project on top of a good reliable resource could have an LRMC in the range of \$80/MWh depending on the technology selected (driven by the temperature and geochemistry of the field). Beyond this, if the geothermal resource is either not ideal or deteriorates over time the cost can climb rapidly.

5.1.4 Hydro generation

Over the past century, hydro generation has been the predominant source for New Zealand's electricity needs. Hydro generation provides significant system benefits with its ability to respond quickly to changing supply and demand conditions. Its rapid response makes

hydro critical in ancillary markets, such as providing frequency keeping and spinning reserve. These will both become more important as intermittent generation is added to the system.

Today hydro contributes 60 percent of New Zealand's power generation on average. This represents installed capacity of 5,290 MW. TrustPower, Meridian Energy and Contact Energy are all investigating new hydro options.

HYDRO – ISSUES

Environmental concerns and access to water rights have limited hydro development in recent years. There remain economically viable opportunities to grow hydro power in a sustainable manner. However, the RMA process places a high hurdle for these projects to overcome. This means that hydro development options tend to have long lead times and take some years to come to market.

HYDRO – ECONOMICS

Similar to wind, the costs of hydro are driven by the local resource and the ease or difficulty of particular sites. Because of this, the LRMC of hydro options are highly project specific.

Hydro projects are capital intensive and take a number of years to develop. As such, economies of scale are important for project economics. Hydro generation costs have increased in recent years, driven by many of the same international factors that have been driving increases in the costs of all power sector infrastructure projects.

The LRMC of possible “economic” hydro generation options ranges from \$75–105/MWh. Many of the remaining hydro opportunities are located in the South Island and are therefore impacted by HVDC charges that add up to \$10/MWh to the LRMC. This charge reduces the number of economically viable hydro projects.

5.1.5 Coal

New Zealand has a substantial coal resource, with recoverable reserves estimated to be at least 8,600 million tonnes. Coal is New Zealand’s largest known fossil energy resource.

Despite this large resource, coal generation is a relatively small part of New Zealand’s electricity generation mix. New Zealand has one major coal generation plant, the 1,000 MW Huntly Power Station (which can also run on gas). Over the last few years, this plant has produced between 10–14 percent of the country’s total electricity production.

This share of coal generation is much smaller than many other countries. For instance, in Australia, coal generation plants produce over 80 percent of the country’s electricity. In the United States, these plants are nearly half of total electricity production. This relatively small share is due to New Zealand’s abundance of low cost renewable generation options and the large, low cost Maui gas field.

Coal generation can play a role in balancing the inherent variability of hydro generation. When hydro inflows are low, coal generation can ramp up production. As hydro catchment lakes become full, coal generation production tends to ease off.

COAL – ISSUES

Coal-fired generation is disadvantaged by its high intensity carbon emissions profile and the range of pollutants that are created. Coal generation also faces significant environmental opposition due to these and other issues, such as landscape effects. The last significant coal plant proposal was Mighty River Power’s Marsden B plant. This project was shelved in 2007 due to marginal economics and significant local opposition.

COAL – ECONOMICS

The capital costs of coal contribute much more significantly to the total generation cost than is the case for a CCGT plant. For a black coal plant, the capital and fuel cost components are roughly equal parts of LRMC. For a brown coal (lignite) plant, the fuel component of LRMC is around half the capital cost component.

A coal generation plant has to be relatively large to realise a low LRMC – in the order of 700–1,000 MW. A new plant of this size would be a large addition to New Zealand’s total generation capacity, representing around 10–15 percent of peak demand. If such a plant was run in a base-load fashion, it would meet energy demand growth for approximately 7–9 years.

Lignite coal plants are the cheapest of the coal options in New Zealand at \$110/MWh (including \$25/t CO₂e price). However, lignite cannot be readily transported, so the location of the plant would be limited to the Southland lignite fields. Because of this location issue, a new lignite plant would require the construction of significant additional AC and DC core transmission infrastructure to deliver its power to market.

North Island based black coal plants are cheapest when sited close to a port (for example New Plymouth, Marsden, Tauranga). But even then the costs of such a plant are relatively expensive at \$115/MWh (including \$25/t CO₂e price). There are clear historical linkages between the prices of internationally traded steam coal and international oil. This means that if oil prices rise we can reasonably expect international coal prices to increase as well.

5.1.6 Coal with carbon capture and storage

Conventional coal generation coupled with carbon capture and sequestration (CCS) technology is a possible large scale future generation option that would generate electricity with little or no atmospheric carbon emissions. While the technology is as yet unproven, estimates of the likely LRMC may be made by making assumptions about the additional capital costs required, additional plant auxiliary demand and the degradation of plant efficiency. These broad assumptions imply a LRMC for black coal plants with carbon capture technology of around \$125/MWh. While this estimate is not too far from the LRMC of a conventional black coal station with a carbon price (for example a \$25/t CO₂e price implies a LRMC in the order of \$115/MWh), the transportation and storage components of CCS also have to be added to obtain a complete estimate of the “coal with CCS” option. With these components added, the LRMC of this option could be in the range of \$140/MWh or more.

5.1.7 Nuclear

Nuclear generation is sometimes suggested as a possible (carbon) emission-free alternative to large scale thermal plants. However, in New Zealand and many other countries there is considerable community opposition to this generation option.

The economic issues associated with committing to large scale nuclear generation in a small country like New Zealand should not be underestimated. Current estimates suggest the headline LRMC of nuclear generation could easily be in excess of \$135/MWh. In addition to this high headline cost there is the largely unknown nature of the “extra” nuclear costs of fuel storage and plant end-of-life decommissioning. For example, it is unlikely that nuclear waste storage could be done in a seismically active country like New Zealand.

New nuclear plants are typically 1,000 MW or greater (although the next generation plants may be smaller in size). The costs of providing the reserve energy required to back up such a plant would be large.

5.1.8 Other technologies

Figure 4 does not show the economics of emerging renewables technologies such as solar photovoltaic (PV), solar thermal and marine (for example, tidal and wave). It will be some years before these technologies become economically competitive in the New Zealand power system without significant subsidies. Internationally, the solar PV market in particular has been developed off the

back of generous feed-in tariff schemes in the European Union and tax incentives in the United States – this is helping the technology to develop and move down the cost curve.

Marine generation technologies are at a very early stage of development with numerous wave and tidal generation prototypes being developed with the help of government (in particular UK) funding. We estimate it could take 5-10 years for these technologies to go into scale production and for costs to significantly reduce.

5.2 The likely mix of New Zealand’s future generation options

On a least-cost options basis we expect that renewables generation in its various forms should be a large portion of future generation investment.

The above discussion identified the issues (particularly economic issues) associated with various forms of new generation projects. There are a range of technology and project specific issues that affect the merit of various options. Based on the issues that have been identified, we expect that renewables generation in its various forms should form a large portion of future generation investment in New Zealand. This conclusion depends critically on the availability and price of domestically sourced gas; if a major, low cost, gas discovery was made, we would expect a greater proportion of gas-fired plants in New Zealand’s generation mix. However, we consider that such an outcome is unlikely, particularly in the short to medium term.

5.3 Transmission

Transmission investment is critical to addressing concerns about security of supply and to enable the long term delivery of the most economic supply options.

The national grid is a critical supporting infrastructure for New Zealand’s national electricity market, where demand is constantly met by supply from competing generators from plants in various locations. The grid facilitates a strong, competitive wholesale electricity market. It enables electricity to be supplied from generation plants with the lowest cost, keeping downward pressure on the wholesale electricity price.

Over the last several years the national transmission system has come under significant pressure as capacity limits have been reached. This pressure is a result of increased demand for electricity and the consequences of under-investment over the last two decades.

In 2008 this pressure was further heightened with the unexpected decommissioning of Pole 1 of the HVDC. At times this has led to market separation in the North and South Islands. This problem significantly exacerbated the 2008 dry winter situation. During this period, there were times when thermal generation in the North Island was unable to supply the South Island due to transmission constraints. Until the HVDC is upgraded (scheduled for 2012) and other key transmission bottlenecks, mostly located in the North Island, are addressed, additional generation in the North Island will be of limited assistance in a dry-year scenario.

Many of the new generation projects under investigation are remote from centres of demand. These generation projects are reliant on a robust transmission system to enable the transport of electricity to consumers.

The transmission investment to supply growing demand and enable new generation projects is a relatively small component of the overall capital investment required. We estimate that transmission investment may comprise around 15 percent of the overall spending on new generation and transmission that is anticipated over the next 30 years.

Some commentators have suggested that building new generation close to demand is an alternative solution to transmission investment. However, these options may not represent the most economic projects available. The optimal mix of generation will constantly evolve with advances in technology and changing fuel costs. The best outcomes for New Zealand at any time will arise from the competitive selection from all generation options. A robust national grid is critical for enabling the best options to proceed.

The key transmission issue facing new generation projects is whether transmission infrastructure will be built in a timely manner to enable electricity to be transported to consumers. New generation projects can often be developed in as little as half the time it takes to build new transmission lines. Accordingly, transmission investment should be considered as an enabler of least-cost electricity generation.

Parties developing the transmission investment process should consider how efficient transmission investments can be implemented ahead of certainty over generation developments. Amongst other things, this process should avoid selecting preferred generation options.

5.4 Resource Management Act 1991 (RMA)

The RMA process can represent a significant hurdle for new generation projects.

Obtaining the right to develop a site for generation under the RMA is a significant hurdle that must be faced by all projects. Every type of generation and individual project will have its own environmental issues that need to be addressed as part of this process.

The delays, commercial arrangements and imposed conditions that stem from the RMA process can change a project's economics considerably or even prevent a project from going ahead. Over the past few years the resource consent process has become increasingly challenging for energy sector projects. This has been pronounced in the case of a number of wind and hydro generation projects and also for large scale transmission projects. Two main factors appear to be driving this. First, consenting authorities have different approaches in managing the consenting process. They have varying levels of resources to handle applications. The time taken to process applications

differs markedly between authorities. Secondly, the overall level of opposition on many energy projects has increased.

At the time of writing the government has introduced a package of proposed RMA reform amendments including measures to streamline the process for projects of national significance. These amendments should hopefully simplify and accelerate the consenting process for future energy projects while maintaining an appropriate balance of consideration to environmental and community concerns.

Applying for concessions on the Conservation estate is also a significant challenge. The framework for assessing concessions lies within a prescribed narrow scope under the Conservation Act 1987 (which is primarily about conservation impacts). This limits the ability to recognise the benefits of renewable energy. Furthermore there are no statutory timeframes, nor clear and transparent processes established under statute for processing concession applications, together with no appeal rights for applicants. This can have significant implications on project timeframes.

6 Glossary

AC	Alternating current. A type of electrical current (flow of electrons) in which the direction of the flow of electrons switches back and forth.
Ancillary services	Ancillary services are generation (or load) that is held on stand-by by the system operator to ensure transmission system reliability in real time.
Baseload plant	A baseload plant operates almost all the time. It uses low cost fuel and is more efficient at full load.
Black-out	A total loss of power to an area. There are different potential causes such as damage to a power line or other part of the distribution system, a power station failing or the overloading of electricity mains.
Brown-out	The power grid voltage is operating at less than the normally accepted tolerance, but voltage is still present. Lines companies may lower voltage during power shortages to reduce load on several customers rather than completely dumping customers.
Brownfields project	Development of a plant or resource that is abandoned or underused or has existing supporting infrastructure.
Capacity factor	The amount of electricity a facility generates in one year divided by the total amount it could potentially generate if it ran at full capacity.
Carbon sequestration	The process of removing additional carbon from the atmosphere.
CCGT	Combined cycle gas turbine. A CCGT consists of one or more gas turbine generators combined with a heat-recovery system used to power a steam turbine.
DC	Direct current. A type of electrical current (flow of electrons) in which the flow is in only one direction.
Demand side management	Utilisation by electricity consumers (the “demand side”) of various options that reduce the demand for electricity supplied on the national grid. These options include energy efficiency initiatives, which reduce the demand for electricity, through to micro-generation and use of other energy such as solar.
Discount rate	A rate of return used to convert an economic cashflow in the future into present value.
Distributed generation	Typically small scale electricity generation that is connected to a distribution network rather than directly to the national transmission system.
Dry-year	Sustained periods of low hydro inflows into catchment lakes. Although often referred to as a “dry-year” the low inflows may occur only over a few months.
Embedded generation	See distributed generation.
Frequency keeping	An ancillary service that keeps the frequency of the grid within its normal band. The frequency keeping station increases or decreases generation within a set band to ensure that supply equals demand on a second by second basis.
Gigajoule	GJ. 1×10^9 joules. A joule is a unit of energy. Commonly used in the New Zealand gas industry as a measure of the volume of gas. $1 \text{ GJ} = 278 \text{ kWh}$.
GWh	Giga Watt hour. A measure of energy production. One million kWh.
Greenfields project	Completely new plant.
HVDC	High voltage direct current transmission system. Used for the bulk transmission of electricity. Relative to AC transmission, HVDC transmission has the advantage of lower transmission losses. The New Zealand HVDC transmission network runs from Benmore to Haywards.
Hydrology	The dynamic processes of water within an environment, including the sources, timing, amount and direction of water movement.
kW	Kilo Watt. A measure of power, 1,000 watts.
kWh	Kilo Watt hour. A measure of energy production. A 1 kW machine (for example, a heater) running for one hour consumes 1 kWh of electrical energy.
kV	Kilovolt. A unit of pressure, or push, of an electric current; 1,000 volts. The measure is used to express the amount of electric force carried through a high voltage transmission line.

<i>Levelised unit cost</i>	<i>Levelised unit cost is the price needed to recover all costs of an investment over its economic life. It is determined by finding the price that sets the sum of all future discounted cash flows (net present value, or NPV) to zero. In this report, levelised unit cost is taken to be equal to LRMC.</i>
<i>Lignite</i>	<i>The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It is brownish-black and has a high inherent moisture content and a low heat content.</i>
<i>LNG</i>	<i>Liquefied natural gas. LNG is the liquid form of natural gas – cooled down to -161°C and maintained at atmospheric pressure. Liquefaction of the gas enables it to be transported at significantly lower costs – the process reduces the gas’s volume to approximately 1/600th of its original volume.</i>
<i>Load factor</i>	<i>Ratio of the amount of electricity used during a specific time period to the maximum possible during that period, expressed as a percentage.</i>
<i>LRMC</i>	<i>Long-run marginal cost. LRMC is the cost of producing one extra unit (or one less) of output when all factors of production are variable. In contrast to SRMC this cost definition includes the capital investment required to deliver the output. In this report, (levelised) unit cost is taken to be equal to LRMC.</i>
<i>Micro-generation</i>	<i>Small sized generation.</i>
<i>MW</i>	<i>Mega Watt. A measure of power, one million watts. Amongst other things, used to define the capacity of generation plant.</i>
<i>MWh</i>	<i>Mega Watt hour (1,000 kWh). A measure of energy production. A 1 MW power-generating unit running for one hour produces 1 MWh of electrical energy.</i>
<i>OCGT</i>	<i>Open cycle gas turbine. An OCGT plant has low capital costs, but high running costs. It is usually operated as peaking or reserve plant.</i>
<i>Peaking plant</i>	<i>A peaking plant operates comparatively infrequently. It has high fuel costs and can cycle on and off. The plant is reasonably efficient under low load conditions. A peaking plant is typically an oil- or gas-fired OCGT.</i>
<i>Petajoule</i>	<i>PJ. 1×10^{15} joules. A joule is a unit of energy. Commonly used in the New Zealand gas industry as a measure of the volume of energy. 1 PJ = 278 GWh.</i>
<i>RMA</i>	<i>Resource Management Act 1991.</i>
<i>Spinning reserve</i>	<i>The available capacity of synchronised plant which can provide immediate assistance during a fall in system frequency.</i>
<i>SRMC</i>	<i>Short-run marginal cost. SRMC is cost of producing one extra unit (or one less) of output in the short run. In this definition of cost, capital costs are excluded since these costs are sunk in the short run.</i>
<i>System costs</i>	<i>System costs are the additional costs that any specific technology imposes on the overall power system. System costs do not include the capital costs to construct generation plant. Examples of system costs are additional frequency keeping services that may be required to manage wind variability and additional instantaneous reserves costs to cover the risk of large thermal plant outages.</i>
<i>Thermal generation plant</i>	<i>A plant that converts heat energy into electrical energy. The heat in thermal plants is produced from a number of sources such as coal, oil, gas or nuclear fuel.</i>
<i>Transmission</i>	<i>A network that transports large quantities of energy. In the electricity industry, a transmission network includes high voltage lines, transformers and switches used to move electrical power from generators to the distribution system. In the gas industry, a transmission network involves large-diameter gas pipelines and associated infrastructure such as compressors.</i>
<i>TWh</i>	<i>Tera Watt hour. A measure of energy production. One billion kWh.</i>
<i>Unit cost</i>	<i>See Levelised unit cost.</i>
<i>Wholesale electricity</i>	<i>Wholesale electricity is supplied by generators and purchased by electricity retailers and some major electricity users.</i>

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