Economics of wind development in New Zealand
Prepared for the NZ Wind Energy Association




Contents

1. Executive Summary

Successful wind farm development in New Zealand is highly dependent on the specific conditions prevailing at a particular site and the market conditions for the purchase of turbines. It relies on securing the rights and consents for sites with high wind yields that are accessible at reasonable cost and appropriate timing of the investment. Investment decisions need to coincide with time of favourable NZD:EUR and NZD:USD exchange rates and low prevailing commodity prices. The optimisation of turbine layout and turbine selection to minimise capital costs while maximising yield is also a critical factor in the success of a wind project development.

Te Rere Hau

The long run marginal cost (LRMC) of a particular wind energy project needs to be compared to the expected future wholesale electricity price to provide an indication of whether the project is likely to be viable. It also needs to be compared to the LRMC of competing technologies to assess the risk of wholesale prices being determined by other technologies and leaving wind investments unable to achieve an adequate return over time.

This report takes data from existing wind projects in New Zealand to assess the actual range of LRMC's for wind projects and how this compares with competing technologies. It also examines the other factors which investors in wind plant consider when making their investment decisions and how these factors have influenced wind investments.

The environment in New Zealand for wind project investment remains challenging with recent average wholesale electricity prices well below the level required to justify investment in wind generation based on its average assessed LRMC. The future environment is highly uncertain, and there is significant uncertainty in relation to the effect of carbon pricing in New Zealand driven by the Emissions Trading Scheme (ETS) and the effect this will have on future wholesale electricity prices. Wind project developers are continuing to pursue projects in New Zealand and some projects have been committed based on assumptions that prices will rise to a level which will achieve the required rate of return over the projects life cycle and thus support the economics of wind generation.

This report demonstrates that for the projects analysed, the LRMC has been between \$78 - \$105/MWh, and therefore it is reasonable to conclude that the best wind projects have been comparable to some alternative technologies. Investment cases have also been influenced by investors own views on terminal value, economic life and portfolio benefits. There is uncertainty with regard to the cost of firming capacity and the HVDC connection however investors may be able to optimise site specific conditions to minimise these costs where possible.

It is important to note that there are alternative technologies which have been viable at lower prices than wind generation has been able to achieve and that this may hold down prices in the short to medium term.

Wind project costs are heavily weighted towards up front capital investment. The ability to time the commitment of capital to coincide with low exchange rates and commodity prices to reduce costs is valuable. Securing the rights and consents for a project site will continue to have an option value to developers provided it can be secured at reasonable cost, to enable them to proceed with an investment quickly when domestic and international market conditions permit.

2. Wind development in NZ

2.1. Operational wind farms

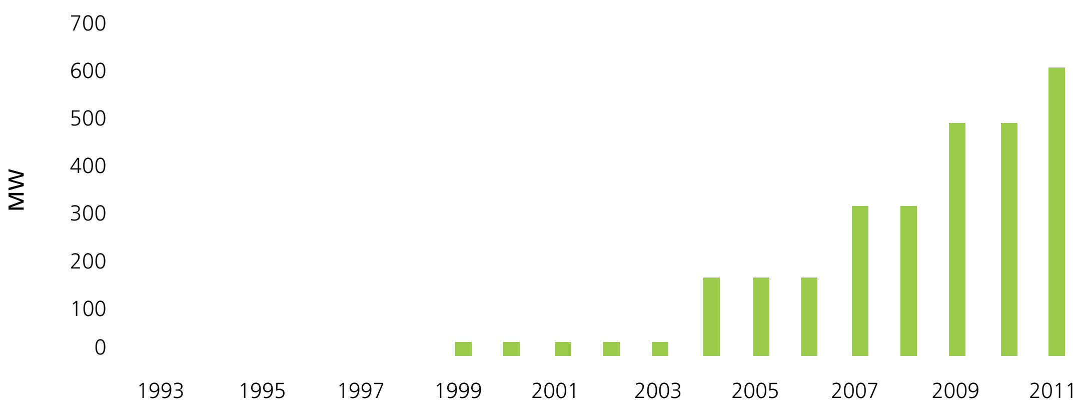
Wind farm development in New Zealand is in its relative infancy when compared to other countries such as the United States, the United Kingdom and Germany. The first wind generation was installed in New Zealand in 1993, since then development has continued at a slow but steady pace. Following with international trends the installed capacity in New Zealand has increased in recent years and as at March 2011 comprised 610 MW [1].

The first wind farms in New Zealand used small turbines which were the technology of the time. Meridian Energy's first wind turbine on Brooklyn Hill (1993) utilised a 225kW turbine and the first stage of Hau Nui (1996) featured 550kW turbines. Trustpower's Tararua Stage I featured 660kW turbines and was constructed in 1999. It is difficult given the time elapsed since the construction of these wind farms to analyse the underlying investment drivers which resulted in the decision to construct these plants and their relevance to assessing the costs of current plant is limited. Meridian's Brooklyn turbine is considered to have been a source of valuable information in assessing wind in New Zealand and has performed exceptionally well by international output standards and is rated as 'best in its class'[2].

Recent wind farm development in New Zealand is unusual in the global context as it has proceeded in the absence of government subsidies and tariff support mechanisms. A number of earlier developments did however receive Government support through the Projects to Reduce Emissions (PRE)[3] scheme in 2003 and 2004. This scheme was designed to support energy projects which would reduce greenhouse gas emissions and involved the allocation of saleable carbon credits to wind projects. While business cases for most wind farms and wider generation development in New Zealand remain commercially sensitive, the overarching criterion of the PRE scheme was that successful projects had to reduce emissions beyond business-as-usual reduction goals. It was designed primarily to bring forward projects that would not otherwise have been economic.

It is difficult to say with certainty the level of financial contribution the successful projects received as the final allocation of the carbon credits and the price at which these credits were sold by project owners is not public. Some or all of the credits which were allocated may also not yet have actually been sold. Certainly there have been a number of projects which were never completed, or completed on time to receive the credits allocated to them. We have not attempted to quantify the impact of this uncertainty. >>

Cumulative Installed Wind Capacity (MW)



Source: NZWEA, Deloitte analysis

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[1] Includes 18 turbines being commissioned in February 2011 at Te Rere Hau

[2] NZWEA

[3] http://www.mfe.govt.nz/issues/climate/policies-initiatives/projects/index.html

The table below sets out an estimate of the potential financial support the projects received based on the volume of credits allocated in the initial tenders. These figures while based on estimates and assumptions, do provide some context for the next wave of construction of wind farms which occurred in 2003 and 2004 with the construction Hau Nui II, Tararua II and Te Apiti. In 2006/2007 wind farms constructed which also received support from the PRE scheme included Te Rere Hau, White Hill and, Tararua III. It is very difficult to determine the impact the allocation of these carbon credits had on the overall LRMC of these projects as the timing and quantum of the cash flows received from the sale of credits is unknown. We have attempted to quantify in broad terms the impact of this and other factors on the investment decisions which drove the decision to construct these projects. This analysis is set out further in section 7.5.

Since 2004 there has been a relatively steady increase in the level of installed capacity in New Zealand with the construction of 12[4] wind farms with over 440MW of capacity. Of these, 3 (186MW) received credits through the PRE scheme representing slightly under half the total wind capacity developed since that date. The remaining 9 (250MW) have been built without any form of direct subsidy or support.

There are several wind farms in construction including NZ Windfarm's Te Rere Hau Stage IV and Pioneer Generation's Mt Stuart taking the total committed capacity with no subsidy support to 300MW. Recently commissioned wind farms include Meridian's Te Uku and TrustPower's Mahinerangi Stage 1. >>

Projects to Reduce Emissions

Developer	Project	Credits allocated	Sales price at $14 per tonne	Sales price at $20 per tonne	Subsidy as % known capital cost
Genesis	Hau Nui Stage II	50,550	$0.7 million	$1.0 million	*n.a.*
Meridian	Te Apiti	530,000	$7.4 million	$10.6 million	4% - 6%
Meridian	White Hill	642,469	$9.0 million[1]	$9.0 million[1]	6% - 7%
TrustPower	Tararua Stage II	528,000	$7.4 million	$10.6 million	12% – 18%
TrustPower	Tararua Stage III	671,250	$9.4 million	$13.4 million	6% – 8%
NZ Windfarms	Te Rere Hau I & II	410,296	$5.7 million	$8.2 million	8% – 12%

[1] $9m is actual figure released by Meridian, implies $14 sales price per tonne.

4 Includes three stages of Te Rere Hau

2.2. Development pipeline

There are currently a number of additional wind farm projects under investigation or seeking consents[5]. A selected list of recently consented projects is summarised below.

- Waitahora wind farm site is located south east of Dannevirke in the Puketoi Ranges, Hawkes Bay. The project is owned by Contact Energy with a capacity of 177MW and an expected annual average output of 700GWh. In December 2010 the Environment court granted Contact Energy full consent for the project. Contact Energy is currently deciding when to progress with the project and have the choice of either 58x2.3MW turbines or 52x3MW turbines.
- Haururu ma raki wind farm is located in Port Waikato. The wind farm is owned by Contact Energy with an expected capacity of 504MW to be generated from 168 turbines and a mean projected average annual average output of 1500GWh.
- Central Wind farm project is planned to be located between Taihape and Waiouru in Ruapehu. The project is owned by Meridian Energy with an expected capacity of 120 MW generated from 52 turbines. The mean annual average output of Central wind is 400GWh with estimated construction costs of $340 million[6].

Te Uku

> A key factor which allows development in the absence of subsidies is New Zealand's high wind speeds and high quality wind resource.

- Turitea wind farm site is located near Palmerston North and owned by Mighty River Power. The total capacity of Turitea is 183MW generated from 61 individual turbines. The Turitea wind farm was given draft approval in February 2011.
- The Te Rere Hau project being developed by NZ Windfarms on the Tararua Ranges in the Manawatu region. Construction is spread over 4 stages with the fourth stage consented in February 2010 and expected to be completed by mid 2011. Te Rere Hau has total capacity of 48.5MW with mean annual average output of 153GWh generated from 97 individual turbines.

2.3. New Zealand specific issues

There are a number of specific factors which affect the economics of wind generation in New Zealand and we have considered only the main issues which have arisen in our discussions with wind plant developers.

High wind speeds

New Zealand is unusual in that it is one of the few countries in the world where wind farm developments have progressed in the absence of subsidies from the Government. A key factor which allows development in the absence of subsidies is New Zealand's high wind speeds and high quality wind resource. A report[7] for the Electricity Commission found that there are a number of sites with wind speeds greater than 8.5 m/s with a further large resource in the 7.5 m/s to 8.5 m/s band. In addition operational performance at some wind farms in New Zealand display some of the highest onshore capacity factors internationally. The yield from this high quality wind resource to a large extent offsets the high capital cost of wind plant and reduces the electricity price at which generation can be economically justified when compared to other countries with less productive wind resources. >>

[5] For a more comprehensive list see http://windenergy.org.nz/nz-wind-farms/proposed-wind-farms
[6] Energy News – Energy Resource Factfile
[7] http://www.ea.govt.nz/our-work/consultations/transmission/draft-report-on-transmission-to-enable-renewables/

Access to sites and transportation

New Zealand's geography creates some highly productive wind generation sites but does not provide for easy access to the highest yielding sites. Many of these sites present developers with unique challenges for the transport, erection and construction of wind farms in remote locations which are poorly served with transport and transmission infrastructure. In addition many of these areas are sub-alpine in nature and face difficulties in winter for access. These factors tend to increase the capital cost of wind projects when compared to international benchmarks.

Lack of long term Power Purchase Agreements by international standards

Electricity generation and retail in New Zealand is dominated by the vertically integrated generator retailers. Historically there has been little appetite for long term electricity off take contract or power purchase agreement (PPA) which is in part due to the integrated nature of the electricity market in New Zealand. Where contracts have been written they have tended to reflect prevailing wholesale electricity prices which have been below the level required to make wind generation economic.

In most other countries investment in wind energy is facilitated by the ability to contract for output for up to 20 years at subsidised prices. Overseas longer term contracts allow developers to use project finance to fund developments as banks tend to be more comfortable with the risk profile on the revenue side when the price and volume is contracted with a credit worthy off taker.

While these are the exceptions, generation development has been dominated by the generator/retailers in New Zealand as these companies are able to use their retail demand as a hedge for their wind and other generation.

This situation has made it difficult for independent generators to enter the market. In contrast, the Australian wind market, while still dominated by large utilities has a number of other investors including private developers, financial institutions, private equity and infrastructure funds which have invested in project financed wind developments supported by long term PPA's and contracts from Renewable Energy Certificates (RECs) available through Large-scale Renewable Energy Target (LRET) policy.

Emissions Trading Scheme

The Government passed substantive amendments to the New Zealand Emissions Trading Scheme into law in December 2009 to introduce carbon emissions pricing from the middle of 2010. Under the current legislation electricity generation has a 2 for 1 surrender clause requiring participants other than forestry have to surrender only one New Zealand Unit (NZU) for every two tonnes of emissions or pay the Government a fixed price of $25. This means the NZU price will effectively be $12.50 per tonne of emissions. After December 2012, businesses will need to surrender one NZU for every one tonne of emissions. In addition a review is being undertaken and due to be completed by the end of 2011. The review is to focus on the high-level design of the New Zealand ETS and will take account of different scenarios for dealing with climate change internationally after 2012. The review will also look at whether the transition measures described above should end as scheduled and the ETS scale up to a full obligation after 2012.

In the long term, the price of CO_2 equivalent emissions is expected to drive up wholesale electricity prices by influencing the long run marginal cost of generation projects which have an emissions profile. As prices increase the range of more expensive renewable generation technologies which become viable will increase. >>

3. Key cost drivers

3.1. Overview

Successful wind farm development in New Zealand is based very much on the specific conditions of particular sites and the prevailing world market conditions for wind generation plant. It relies on securing the rights and consents for high yielding sites and appropriate timing of the investment. This includes the timing of investment decisions to coincide with favourable exchange rates and the optimisation of turbine layout and turbine selection to minimise capital costs. It also includes other approaches to minimise operational costs such as connection to the local distribution network rather than transmission level, or the maximisation of portfolio benefits for a generator with a retail book and diverse generation types.

A simple averaging approach does not properly explain the investment decisions which have occurred to date and those which are currently being undertaken. This report analyses the range of delivered cost of electricity for wind development in New Zealand to date and provides a view on the potential long run marginal cost in the future based on the research available to date. It also considers the wider factors which influence the economics of wind generation and how they have been taken into account in developments to date.

3.2. Cost structure of wind farm

The cost structure and therefore associated LRMC of wind is dominated by high capital costs and relatively low fixed and variable operating costs compared with alternative technologies such as those using fossil fuels. Broadly wind plant capital costs are made up of the following components.

Breakdown of wind farm costs

Cost category	Range
Turbine capital cost	70 - 75%
BoP (switchgear, access, foundations, site electrical)	15 - 19%
Grid connection	8 - 10%
Total project costs	**100%**

Turbine transport costs to site in New Zealand can comprise a material amount of the turbine contract price and can have a material impact on total capital costs. Contract pricing for turbines is generally provided in Euros however with the move to greater manufacturing of components outside Europe, a number of components can also be priced in USD, particularly for blades. Shipping tends to be dominated in USD and is a function of oil prices and transport distances. Again New Zealand is disadvantaged due to the distance from the manufacturing sites for key components however this disadvantage is reducing as some manufacturers are moving production to China and the United States.

The following table summarises the cost breakdown of key components of wind turbines.

Turbine capital cost breakdown

Cost category	Range	Contract pricing
Nacelles and power conversion	55 – 60%	EUR
Blades (Class I turbine)	14 – 15%	EUR
Tower	9 – 12%	EUR or USD [1]
Transport	7 – 10%	USD
Installation & other	8 – 10%	EUR
Total turbine capital cost	**100%**	

[1] Pricing terms dependent on point of shipping

The movement of production to China by some manufacturers is likely to create some downward pressure on turbine prices, however as discussed in section 4.1 current downward price trends are overwhelmingly due to competition between manufacturers. The ultimate reduction in prices is however likely to be limited due to the low labour and high materials cost content in wind turbines. The labour needed for wind turbine production also tends to be relatively skilled and hence costly even when relocated to China.

3.3 Commodity prices

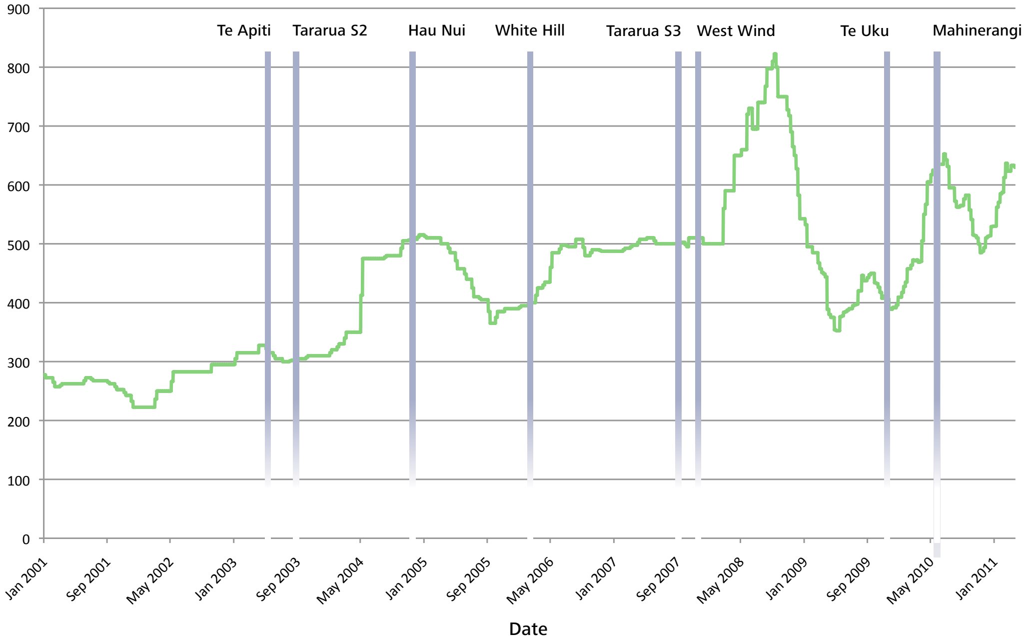
For New Zealand developers there are several key commodity related cost drivers including steel prices, exchange rates, shipping costs (including oil prices) and to a lesser extent the cost of copper, aluminium and other metals used in construction. The cost of turbines represents 70 – 75% of total capital costs and is subject to movements in the NZD:EUR exchange rate. Approximately 12% of the turbine cost is subject to movement in steel prices. Steel prices and movement in other metals such as copper and aluminium will also affect pricing for electrical components. Turbine pricing will typically be provided on a firm basis for around 90 days with contract adjustment mechanisms for steel (turbines/towers) and bunker fuel (shipping). >>

Prevailing exchange rates, and to a lesser extent commodity prices, play a fundamental part in the commercial viability of wind projects and have a profound influence on the NZD capital cost of the project.

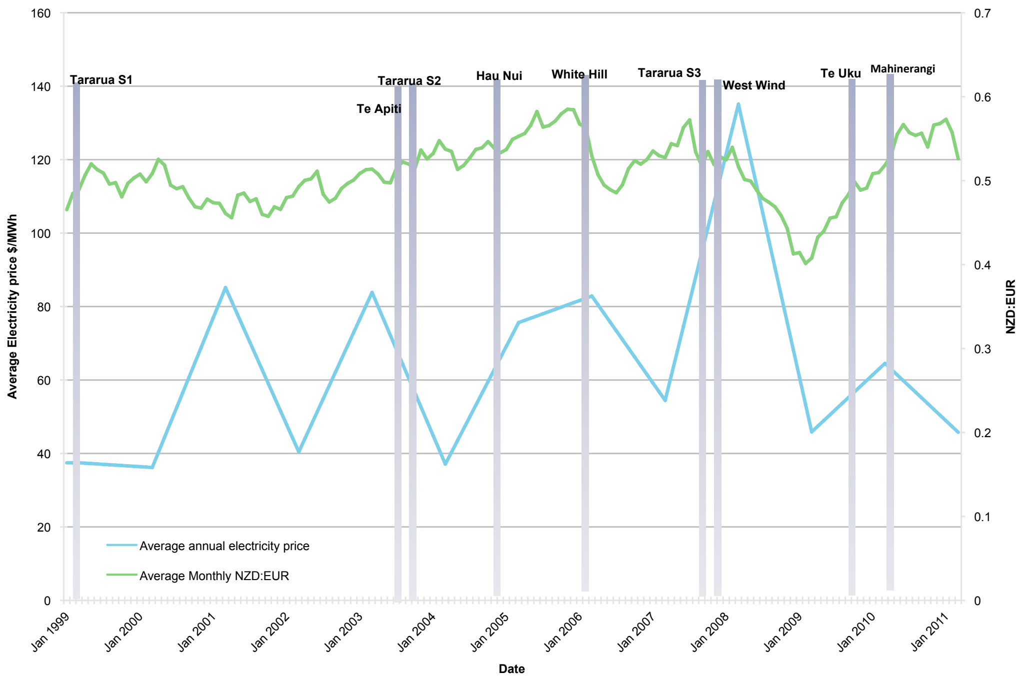
Wind project developers need to time their investment to coincide with favourable exchange rates and lock in these rates against firm EUR and USD pricing at the time the investment is committed.

The following charts show the monthly average EUR exchange rate, steel (hot rolled coil) and annual average electricity price. Highlighted is the point at which construction commenced on a number of major wind farms. The chart are only illustrative as the actual investment decision generally to precedes the construction date by 6-12 months. The charts illustrate that most investments have been made at or above an exchange rate of NZD:EUR 0.50 and steel prices below €400/tonne. >>

Hot Rolled Coil Price Index



Average Electricity Price v Euro




White Hill

3.4 Economies of scale in wind

Capital cost

Analysis of international experience[8] tends to support the view that wind and renewable generation as a whole tends to have limited economies of scale. In fact larger wind farms (i.e. higher number of turbines and larger capacity turbines) are likely to have limited overall savings across shared infrastructure and turbine discounts for bulk purchase are typically only offered under Frame Agreements[9] for guaranteed annual turbine purchase numbers. Such agreements are understood not to exist in New Zealand given the size of the market and limited number of developments. This is consistent with both our analysis of New Zealand projects and discussions with market participants which show a reasonably flat capital cost profile on a per MW installed basis regardless of the size of the wind farm. Our analysis has indicated that some diseconomies of scale may exist with larger wind plants costing more per MW installed than smaller developments.

There are however a relatively small number of data points and as discussed there is no 'average' site and each development has unique features. Developers try to capture each sites specific opportunities to maximise the return from their investment. Examples of these on more recent smaller scale developments include:

- Mahinerangi Stage I using the existing 33kV transmission line used for the Waipori hydroelectric scheme.
- Mt Stuart will use existing roads eliminating the need for any new access road construction.

In a more generic sense all generation projects which are able to connect to 33kV lines (such as at Te Uku, Mahinerangi and Mt Stuart) do not require the installation of a main transformer. Generation projects with an installed capacity of less than 60MW do not incur ancillary reserves charges and those without grid connections do not incur system charges. It should be noted that where a site has a greater potential these factors may contribute to the decision to constrain project size. >>

Analysis of international experience tends to support the view that wind and renewable generation as a whole tends to have limited economies of scale.

[8] www.decc.gov.uk/assets/.../71-uk-electricity-generation-costs-update-.pdf

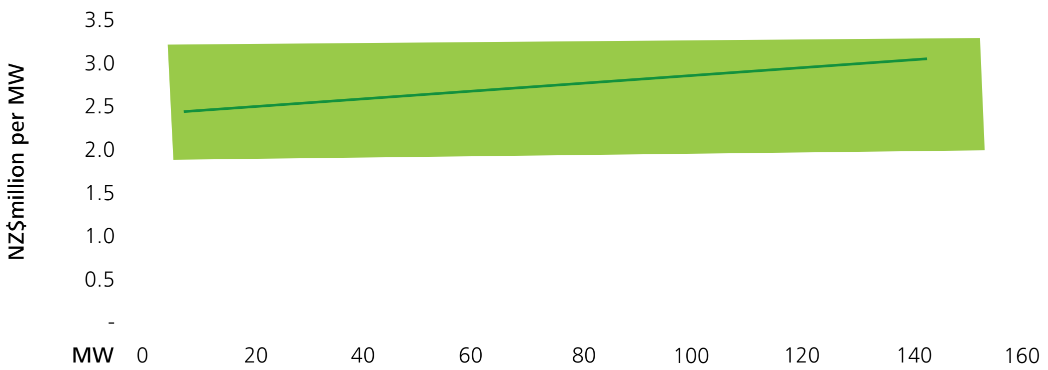
[9] We are unaware of any Frame Agreements in place in NZ. Typically these agreements are for large scale commitments to purchase significant volumes (i.e. in excess of hundreds of WTGs over several years).

The chart below shows the general trend of installed costs across completed projects in New Zealand. While we have attempted to normalise the cost over time the large changes in turbine prices over the last 5-6 years make this difficult, in addition there is a relatively small number of data points with which to create the data – the trend line represents the best fit linear trend with the shaded area representing the outer range in which the observed values fell within. The chart shows capital cost per MW increasing as the size of the wind farm increases however this may in part be due to the fact that the larger plants are more recent developments and wind turbine costs have tended to rise over time.

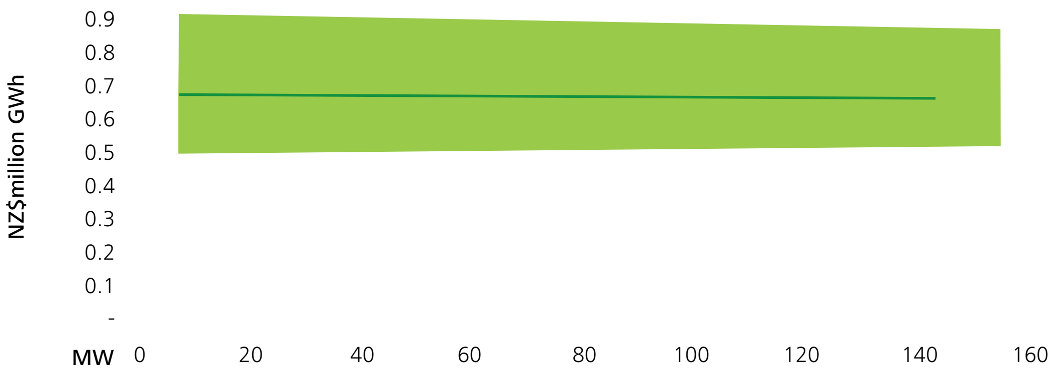
There are no very large projects (i.e. greater than 150MW) constructed in New Zealand, however anecdotally it may be that projects of the scale of Haururu ma raki and Project Hayes are able to achieve some economies of scale around shipping, craneage and other bulk services but this has yet to be proven. Given the high proportion of wind turbine costs in the total capita expenditure, any economies achieved are likely to be limited.

The use of cost per MW used in the media and by market commentators to discuss trends in capital costs is somewhat misleading. From a general perspective the use of this metric can however provide a view of trends and a crude measure for preliminary assessment of project economics. It does not however capture the most important factor in wind economics - the output in GWh. This is the crucial factor which relates to turbine selection and the ability to justify higher capital costs. The chart below analyses the trend in cost per GWh with plant size and indicates a very slight trend downwards in cost per GWh as plant size increases. These charts are based on the population of committed wind plants in New Zealand. >>

Capex per MW installed



Capex per GWh/year



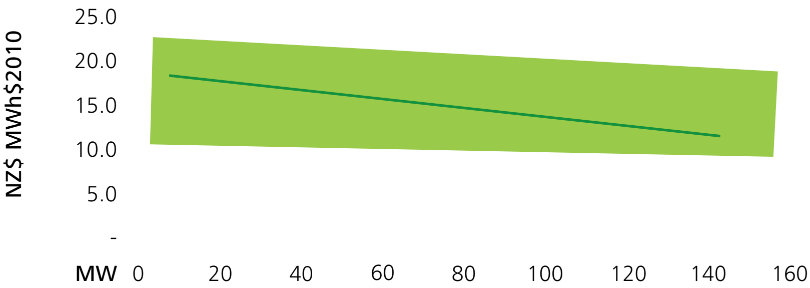
One of the key trends which is likely to improve the economics of wind generation is that of increasing yield from turbines. Technology advances in turbine manufacturing such as direct drive turbines (fewer moving parts), lower cut in and higher cut out speeds and increasing swept area are continuing to increase yield from similar sized turbines. For example on an 8 m/s wind speed site with a 90 metre hub height, the output at a theoretical wind farm could be 7,000GWh, increasing the hub height to 100 metres allows a longer blade to be used, which in turn results in an increased swept area. Under this configuration installing a turbine with 6 to 8% greater capital cost can result in up to 18% more output. Over the life of any investment these trade-offs can significantly improve the economics of wind generation and allow sites which were previously uneconomic to be developed.

Notwithstanding the trends discussed above, there will always be an optimal site configuration (i.e. number, size, model and arrangement of turbines) that will achieve the lowest cost of generation for each site where planning and consent conditions allow for them. It is up to the developer to determine this optimal level and we have not attempted to determine the impact of these within project efficiencies on the economics of investment decisions.

Operating cost

Operating costs show that economies of scale appear to be being achieved in New Zealand wind project developments as shown in the chart below.

Opex per MWh



There are a number of relatively fixed costs such as insurance, corporate overheads/management time, landowner costs and grid/connection charges. Therefore having more turbines overall can generally provide some additional efficiencies. The major component of operating cost in a wind farm however is the operations and maintenance (O&M) charges. There are a range of different options and the majority of the major turbine manufacturers offer O&M contracts ranging from a minimum of a couple of years (typically covered under the warranty period) through to up to 10 years contracts, with rights of renewal for 5 + 5 years. These tend to be contracted on a per turbine basis - discussed further in section 4.3.

One factor in New Zealand which should be considered is the extent to which turbine manufacturers have a footprint in the Australasian region and how having a locally based team of engineers and maintenance staff may influence O&M pricing. There are potential efficiencies which can be gained by consolidating technology types and therefore the ability to carry less spare parts which can be allocated across several sites. Such examples are the Vestas V90 model used by TrustPower at Tararua III and Mahinerangi and the Siemens 2.3 model used at Meridian's Te Uku and West Wind.

4. Modelling assumptions

This section summarises our modelling approach in determining the LRMC of wind plant and the key assumptions used in our analysis. Our primary data sources for cost and plant performance has been the actual achieved performance on wind generation plants in New Zealand. This dataset has been compiled from a variety of sources. In particular we acknowledge that several market participants have provided information to us in confidence.

The output of the analysis is presented in a manner which protects the confidentiality of the data sources. It should be noted the dataset does not comprise every constructed wind farm, however we believe the output presented in the following sections is representative of the majority of the installed MW capacity of projects in New Zealand. In some cases we have supplemented our data with that for committed plants which are currently under construction or commissioning. Some data relates to projects developed at different times and we have attempted to normalise this to make costs comparable based on current $2010 prices.

4.1 Capital costs

Our modelling has used the following range of capital cost assumptions. Capital costs are all inclusive of turbine supply, transport to site, erection, balance of plant and grid/distribution connection.

It is difficult from the information available for the projects to ensure complete comparability of costs between projects. Whether, for example, all the developers internal costs including development, design, consenting etc have been capitalised. For the purposes of our modelling and given the relative immaturity in the industry and limited data points in New Zealand, we have assumed that the range of outcomes represented in our dataset are sufficient to include all costs including design and build versus EPC contracts and that any gains from a developer run process are likely to be offset by inefficiencies lost through the learning process as developers continue to gain experience in the construction of wind farms in New Zealand. Development costs have tended to be expensed by New Zealand developers and have been relatively small as a proportion of the overall construction costs. We have consequently assumed that we can ignore whether they have been included or not for the purposes of our analysis.

We have combined the capital costs with project specific operating and output assumptions to give the best overall range of LRMC for constructed projects in New Zealand. While the majority of the actual costs remain commercially sensitive the range in which our modelling falls is shown below.

Capital expenditure

$ million	Per MW	Per GWh/year
Low	2.0	0.5
Average	2.7	0.7
High	3.2	0.9

Capital cost range

Publicly available information for constructed New Zealand wind farms put cost on a per MW basis of between $2.0 million and $3.2 million. For the projects we have analysed and that feed into this dataset on a per GWh/year basis this varies between $0.5 million and $0.9 million. >>

While the absolute cost of turbines in New Zealand remain undisclosed - trends in price movements downward reflect global experience.

Future trends in capital costs

What is evident in both New Zealand and internationally is that overall capital costs have come down significantly from highs seen before the global financial crisis (GFC). This can be attributed to a number of different factors but consensus from the market participants we have spoken with states this is overwhelmingly to do with competition. The competition has arisen due to over supply of manufacturing capacity - there was a time when lead times for turbine manufacturing were greater than 12 months. In addition turbine manufacturers out of China have vastly increased their market share globally which has resulted in lower pricing being required from the traditional European and US manufacturers. China's turbine market growth is supported by its booming internal market, following this trend China has become an attractive place for turbine and component manufacturing due to cheaper resources availability. In addition having manufacturing facilities in China for developers in New Zealand is beneficial as it reduces significantly the cost of shipping. This is particularly true for components such as blades and towers. Towers given their weight and size can be manufactured as close as Australia which further reduces cost.

The most recent issue of the Bloomberg New Energy Finance Wind Turbine Price Index[10] shows that prices have dipped below €1million per MW for the first time since 2005. The index was comprised of more than 150 undisclosed turbine contracts, totalling nearly 7GW of capacity in 28 markets globally – with a main focus on Europe and the Americas. We understand from New Zealand participants that turbine pricing in New Zealand has been more competitive in recent times and while the absolute cost of turbines in New Zealand remain undisclosed - trends in price movements downward reflect global experience. The report also states that procurement officers for the developers in the survey expect prices to stabilise around current levels for 2011 and 2012, with few further reductions in the near term. They expect gradual increases in pricing from 2012–13 as global demand recovers.

While the terms of contract for turbine supply remain confidential, shipping to New Zealand, including transport to site can comprise a significant overall proportion of the capital cost of projects. Estimates for this range for between 7% and 10% and for complex remote sites may be even higher.

4.2 Plant life & through life costs

Trends in capital expenditure / turbine life

Assumptions around the economic life of wind turbines and the through life maintenance costs have a material impact on the economics of projects. The market view on turbine life in New Zealand and that which we have used for our analysis is 20 years, this is consistent with investment analysis we have observed. This compares to analysis from the UK[11] which used a standard life of 25 years. We recognise therefore the importance of understanding the impact of using different plant lifes and the results of our modelling show that increasing the assumption for plant life from 20 to 25 years (without any additional expenditure) would result in a 6% – 8% lower LRMC.

A number of projects have included costs for possible breakages and budget for the replacement of the most expensive component in the turbine at least once during its life. Components that fail could include blade bearings, gearbox, yaw gears, generator, actuators, fluid pumps and transformers. The most expensive parts to change are the nacelle and gearbox and a number of projects have allowed for replacement of these components during the life of the plant.

Typical O&M should be completed on a preventative basis and manufacturers when they have responsibility for the contract will often undertake in year 8 or 9 a full overhaul including replacement of all hydraulic hoses and components with a design life less than 25 years. This can take 1 – 2 weeks at a cost of around $250k per machine. Newer turbine designs have fewer moving parts and complex components such as gearboxes which are expected to reduce the through life cost of the latest plant. >>

[10] http://bnef.com/PressReleases/view/139

[11] www.decc.gov.uk/assets/.../71-uk-electricity-generation-costs-update-.pdf

The economic analysis presented is based on a 20 year life reflecting our discussions with wind farm operators and equipment manufacturers. In practice this may not reflect the actual plant life. Actual life is determined by engineering design and operation and maintenance protocols as well as technical obsolescence considerations. For example turbines on a low turbulence site should last longer; even the same make of turbine on the same site can have a different life due to different wind conditions across the site; and there are exchangeable parts which can extend the life of turbines too. Siemens still have turbines running in the USA after 27 years[12].

4.3 Operating costs

We have surveyed O&M costs from the operators of wind plant in New Zealand and adjusted where possible to ensure it includes all operating costs for the plant. For the purposes of the analysis the figures below are assumed to include all of the following costs. They exclude reserves market (cost & income) and avoided transmission revenue – these are included in separately in our analysis and discussed in section 7.5.

- Service & Maintenance (in house or contracted)
- Repairs
- Management / overhead
- Insurance
- Transmission & connection
- HVDC charges (if any)[13]
- Land rental

Operating cost per MWh

$	Per MWh
Low	10.0
Average	16.0
High	22.0

There are a small number of available data points for New Zealand. Part of this limitation arises due to the relative infancy of the sector in New Zealand with few turbines having yet been in operation in New Zealand wind conditions for a significant proportion of their expected lifespan. We have used international benchmarks to test the reasonableness of the assumptions used. Research into O&M costs has been limited, although the European Wind Energy Association (EWEA) plans to produce a report on cost trends. National Energy Renewable Laboratory (NREL) states that despite limited data availability, projects installed more recently have, on average, incurred lower O&M costs than older projects in their first couple of years in operation. Likewise, larger projects appear to incur lower O&M costs than do smaller projects, and O&M costs increase as projects age.

O&M costs are estimated to make up approximately 20 - 30% of the LRMC over the lifetime. However, costs are lower at the beginning of a turbine's life (10-15%), increasing to at least 20-35% by the end of the turbine's lifetime[14].

International benchmarks indicate that total annual charges represent a percentage of the installed cost, often quoted between 3% and 5%. The following is a comparison[15] in Euro adjusted to $2010, showing New Zealand to be at the low end of international markets. This is partly due to New Zealand labour costs being cheaper than the EU and USA. >>

Opex per MWh ($2010)- Global Benchmark

COUNTRY	NZ		GERMANY	UK	USA
Currency	NZD	EUR	EUR	EUR	EUR
Low	10.0	5.2			
Average	16.0	8.3	22.5	20.1	16.4
High	22.0	11.4			

Source: Deloitte analysis, WindPower Monthly
1 NZD = 0.52 Euro

[12] NZWEA

[13] We understand there are no South Island wind farms currently incurring HVDC charges and therefore the figures presented below do not include the impact of HVDC charges. We discuss HVDC charges further in section 4.4 and analyse the impact of HVDC charges on LRMC in our sensitivity analysis in section 7.7.

[14] http://www.wind-energy-the-facts.org/en/part-3-economics-of-wind-power/chapter-1-cost-of-on-land-wind-power/operation-and-maintenance-costs-of-wind-generated-power.html

[15] http://www.windpowermonthly.com/news/1010136/Breaking-down-cost-wind-turbine-maintenance/

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4.4 Transmission and connection

Transmission and connection costs vary depending upon whether a project is connected to the grid system or local distribution network. We have included actual costs for each project where they are available. With regard to the cost of the HVDC linkage between the North Island and the South Island there are a number of different views regarding the impact of the cost and pricing methodology on the economics of wind farm investment in the South Island. Under the current pricing methodology the cost can vary between different parties. We do not comment on the impact on investment decisions but rather have shown in our sensitivity analysis the impact of varying charges on the LRMC of a potential South Island wind farm can be between 8% and 14%.

Transmission and connection costs vary depending upon whether a project is connected to the grid system or local distribution network.

4.5 Yield

We have surveyed the owners of wind plant or used publically available information and used the actual achieved yields on each site as the basis for assessing LRMC. Some of the plants have been in operation for a relatively short time and clearly there will be some variability of yield over time.

4.6 Location factor

The location factor relates to nodal pricing points relative to the Hayward's price. The model normalises for location effects by adjusting for the transmission location factor for the key regions this normalisation results in a comparable LRMC at the Hayward's grid pricing point for all the projects analysed.

4.7 Discount rate

The NPV is derived based on a 7.32% real post tax discount rate - equivalent to a 10% nominal post tax discount rate at a 2.5% long run inflation rate. This nominal post tax rate is, in our view, representative of a typical hurdle rate applied by investors in generation projects in New Zealand and in line with our assessed cost of capital for generation companies in the New Zealand market.

The LRMC analysis presented in this report is highly sensitive to changes in discount rates. Our sensitivity analysis shows a 1% move in the nominal discount rate can have a 6 – 8% impact on the LRMC of a project.

4.8 Tax rate and tax depreciation

To be consistent with commercial business case assessment we have included tax on income at 28% corporate tax rate which is partly offset by the tax depreciation shield which utilises a 20% reducing balance depreciation rate. For simplicity we have assumed that where the project generates tax losses these are realised in the year they are generated and thus provide an immediate cash benefit. By utilising this assumption we imply the project will be owned by a portfolio investor who will be able to utilise the losses to offset other income within their group.

5. Wind specific issues

Investors in wind projects need to consider a range of issues specific to the technology. This section summarises the main considerations in relation to wind investments, their potential impact on the economics of investment in the technology and how these matters have been treated in various wind project investments in New Zealand.

5.1 Variability of output

Wind is inherently variable and the operator of wind generation has no control over the timing or level of generation output. Operators of controllable generation are able to time the output and level to capture price peaks during periods of high demand and earn a price in excess of the average prevailing wholesale price. When dispatchable generation is run as base load the price captured is closer to the long term average, when plant is run as mid merit or peaking it tends to capture an increasing margin over the long term average.

Analysis of specific wind farms in New Zealand has observed that wind plants tend to earn a discount to the long term average price, this is also know as a GWAP/TWAP factor (generation weighted average price / time weighted average price). There are a range of explanations as to why this discount exists most of which relate to the intermittence of wind generation and the fact that it is not dispatchable. When wind generation is not running higher cost plant runs and sets the marginal price. When the wind blows wind plant is dispatched and displaces this higher cost plant reducing the price which would otherwise be set. Consequently wind plant tends to dampen prices when it runs. In addition there are other factors such as site wind profiles versus daily demand profiles and seasonal variability which can influence achieved GWAP/TWAP factors.

Existing wind plant generally has average yield factors in the region of 40%. These yield factors are based on the installed capacity and reflect the total production against the total installed capacity.

Investors in wind plant have taken this into account by applying a discount to the expected wholesale price which a wind plant is expected to achieve in their investment modelling. The discounts observed for operating wind plant have been as high as 15% however investors have generally applied a discount of 10% or less.

Our raw LRMC analysis has ignored this discount for analytical purposes on the basis that it is not a "cost" of wind plant as such but part of the wider investment decision process. We adjust for it separately in our analysis.

5.2 Cost of reserves

The New Zealand electricity system operator maintains reserve capacity and allocates the cost of its provision to generators. Existing wind plant generally has average yield factors in the region of 40%. These yield factors are based on the installed capacity and reflect the total production against the total installed capacity. While these factors are calculated over a year wind plants in New Zealand operate around 85% of the time[16]. Despite this wind operates variably requiring backup firming capacity to be available when wind plants are operating. Currently the cost of this firming capacity is not charged directly to the operators of wind plant. The cost of providing this capacity is generally carried by the operators of controllable generation plant who may be able to use this ability to capture prices greater than the TWAP.

The cost of this firming capacity has not been included in our LRMC analysis but it is clearly an overall cost to the market. Various studies have been carried out on the cost of this firming capacity which have estimated the current cost as being in the region of $2/MWh. The cost of firming capacity is expected to rise if wind plant grows to become a larger proportion of the overall generation capacity. As these costs grow there may be increasing pressure to tie them back more directly to the wind, or other non firm plant , which creates the need for them which is a risk which needs to be considered by investors in wind plant.

5.3 Hydro firming

The use of hydro plant to provide firm support capacity for wind has been considered in a number of investment cases. This has primarily revolved around the ability for hydro plant to firm wind but has also taken into consideration the fact that wind plant operation reduces the demand on hydro plant and has the potential to save water. This is discussed in more detail in the portfolio benefits in the following section.

[16] Meridian Energy, Facts about wind energy 2011.

6. Investment criteria

6.1 Overview

The LRMC of a generation asset is ultimately a measure of levelised generation cost which assists in understanding the relative cost competitiveness and overall investment attractiveness of one technology class over another. LRMC is not the single determinant of whether one investor will choose to construct a particular wind farm over another. Each investor has their own views and circumstances in relation to the specific factors which influence their investment decision. These can include access to capital, cost of capital or discount rate, view of the current and long term trends in electricity pricing, the impact which terminal value assumptions have on project valuations, the effect of construction of the wind farm on the financial performance of other assets held in the investors portfolios and the alternative cost of hedging a retail portfolio base. We discuss each of these factors in turn and consider the possible impact on LRMC in qualitative terms. We expand this analysis in section 7.6 to illustrate the impact in financial terms on LRMC of these various drivers.

6.2 View of wholesale price

Wind project investors view of the future wholesale price of electricity is probably the single most important factor in making an investment decision in wind or any other generation technology. The view also has to be taken over an extended period of up to 25 years however there is no observable forward market price beyond two to three years and the market within this limited timeframe is very thinly traded.

A sufficiently aggressive view on future prices will justify virtually any investment however investors need to bear in mind that the higher the assumed price the greater the range of alternative technologies or projects which will be feasible at a lower price. The major risk to investors is that alternative competing technologies are brought into the market which can provide an adequate return to investors at a lower price and consequently the wholesale price never rises to the anticipated level leaving wind investors with stranded assets or facing substantial write downs in the value of wind assets already built. Wind assets have a low short run marginal cost (SMRC), i.e. no fuel or start-up costs and hence the likelihood of stranding, once built, is lower, however investment returns can still be below expectations. It is worth noting that alternative technologies also face varying risks for example carbon and fuel costs which can result in low actual returns when compared to expectations.


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There are a range of price forecasts available from various sources including brokers, Government and market analysts as well as implied prices from the trading prices of listed generation companies. Most of these are short term and based on the providers analysis of the cost of production. They do however provide a consensus view which can provide support for forecasts for wind plant investments.

6.3 Discount rate

Investors in wind plant are aiming to achieve a rate of return from the project commensurate with the risks associated with the plant and the market within which it operates. Existing players in the New Zealand market have tended to use their assessed cost of capital or a specified hurdle rate as the discount rate. The hurdle rate is generally set at a slight premium to the cost of capital to account for the fact that the investment assumptions, such as capital and operating costs, are not likely to be firm at the point at which the investment decision is made. This provides some headroom to allow for any unanticipated increases in costs and protects the investment returns as assessed at the project outset.

At earlier stages in a projects development the input assumptions are likely to be less firm and typically investors will apply a higher premium or hurdle rate over cost of capital. Investors who use only their cost of capital as the discount rate even at the early stage of a project run the risk of abortive work if cost estimates rise as they become more certain or of making investments which risk becoming impaired at an early stage in their life. An alternative approach is to include a substantial contingency amount in both capital and operating cost estimates and refine this contingency through the development process. >>

6.4 Terminal value

Investors in wind plant have used a range of assumptions as to what will happen at the end of the projects life. The value which the project will have in 20 to 25 or in some cases 40+ years time is highly uncertain but can substantially influence the viability of an investment.

Given the uncertainty a conservative approach is generally advisable. This can include a shut down of the plant at the end of its assumed life less any abandonment costs or a managed run down and reduction in capacity. Other approaches include a rebuild and relife of the plant or attributing substantial value to the site itself due to the nature of the wind resource. Where this occurs strict engineering and asset management principles (including maintenance regime) need to be applied. Some investment cases also assume that significant proportions of the installed equipment, particularly distribution and transmission components will be reused in any rebuild or life extension of the plant.

A number of wind plants have been committed based on conservative terminal assumptions whilst others have depended upon a higher end of life residual value based on site specific factors to support investments.

Mahinerangi

6.5 Portfolio effects

Wind investments in New Zealand have generally been made as increments to a larger portfolio of generation plant of different technologies and investors have considered the wider benefits which accrue to their generation fleet as a whole from the addition of wind. Owners of hydro plant have considered winds ability to conserve water, making it available for generation at times of higher prices whilst others have considered its fit with controllable generation to provide firm capacity and increase their ability to contract for firm output from wind capacity.

The portfolio effects are specific to particular investors and the extent to which they can be directly attributed to the wind plant itself varies from case to case.

6.6 Tax benefits

Wind plant currently enjoys accelerated depreciation in New Zealand. This provides a tax benefit to the owner but the value and timing of that benefit depends on whether the owner has other taxable income against which to offset the accelerated depreciation deduction. In a portfolio the tax benefits can be used immediately to offset other tax liabilities. In a stand alone investment the losses must be accumulated and then offset against future liabilities as the assets profit increases, reducing the overall benefit.

6.7 Natural hedge for retail base

Most New Zealand wind plant investors also have substantial electricity retail businesses. These retail businesses essentially form a long term hedge, into which electricity can be sold on largely fixed price tariffs. This essentially fixes the price which can be achieved for the plants output whilst at the same time reducing the retail businesses exposure to potentially volatile wholesale spot electricity purchases. A stand alone wind asset however would need to balance its output with customer demands in order to match the profile of the retail load. When operated as part of a portfolio this can be achieved using other plant with overs and unders sold into the wholesale market. This is a key reason why wind plant has almost exclusively been developed as part of a larger portfolio of plant in the New Zealand market.

While we are not able to conclude on the investment appetite of different types of participants in the sector, there may be opportunities for other participants to operate in future if hedge market liquidity and the range of hedging products improves. >>

7. Economics of wind projects in NZ

7.1 Summary

Typically reports assessing the relative economics of generation projects tend to use calculations of the levelised cost of electricity (LCoE) or long run marginal cost (LRMC) to determine the relative competitiveness of various technologies. Assuming that all investors in generation assets were equal and with the same investment appetite, views on future electricity prices and access to capital –theory suggests that those projects with the lowest overall LRMC would be constructed first. However while a useful measure in understanding the influence of key cost drivers, what LRMC does not provide is a view of the other factors which are present in business cases approvals for new projects – items which cannot be modelled under simplified conditions, items such as portfolio benefits, avoided transmission revenue, costs of firming, views on terminal value to name a few. The basic theoretical approach also takes no account of the fact that all projects and investors are not equal and their views will differ on the future environment in which projects will operate. Consequently one investor may proceed with a particular project when another would not based purely on a more or less optimistic view on future market conditions.

The following section therefore sets out the results of our analysis of constructed wind farms in New Zealand and their 'raw' LRMC. We then further explore factors which may have influenced the investment decisions of these projects to further narrow the range of LRMC. We conclude with a sensitivity analysis which attempts to the illustrate the impact some of these factors have on the LRMCs derived in our modelling.

7.2 Long run marginal cost of electricity

For the purposes of our financial modelling we treat LRMC and LCoE interchangeably. We have adopted a definition of LRMC as being:

> *The breakeven electricity price required to set the net present value of future capital and operating costs to zero. The equation takes into account the total amount of electricity produced over the life of the investment.*

For those who view these investments from an engineers perspective the modelling results in the same LRMC as would be derived by the following formula:

LRMC = ToTC / NPVEG

LRMC = Long run marginal cost of electricity ($/MWh)

TOTC = Net Present Value (NPV) of total costs (capital and operating) ($)

NPVEG = NPV of net electricity generation (MWh)

7.3 Key assumptions affecting LRMC

Our modelling assumptions have been based on the actual costs and other operating parameters for wind plant operating in New Zealand wherever possible. We have set out in this report the basis of key modelling assumptions used to drive the LRMC model. The data for individual projects is not all available publicly and is in most cases confidential to the project owner. The table below, however, summarises the ranges for the various assumptions which we have used in our modelling of LRMC. >>

Category	Description	Assumption
Timing	Life of project Length of construction period Residual life	20 years 1 year 0 years
Investment	Cost of capital/hurdle rate Tax rate Tax depreciation	10% nominal post tax 7.3% real post tax 28% 20%
Capital cost [1]	Turbine Foundation / Civil BOP Grid/Transmission	NZ$2.0 - $3.2 million per MW or, NZ$0.5 - $0.9 million per GWh/year
Operating cost	O&M Insurance Rates Land rental	NZ$10.0 - $22.0 per MWh of output
Output	Rotor diameter / swept area Hub height Turbine suitability Turbine power curve Wind speed Site characteristics	Implied capacity factors of 38.0% to 45.0%

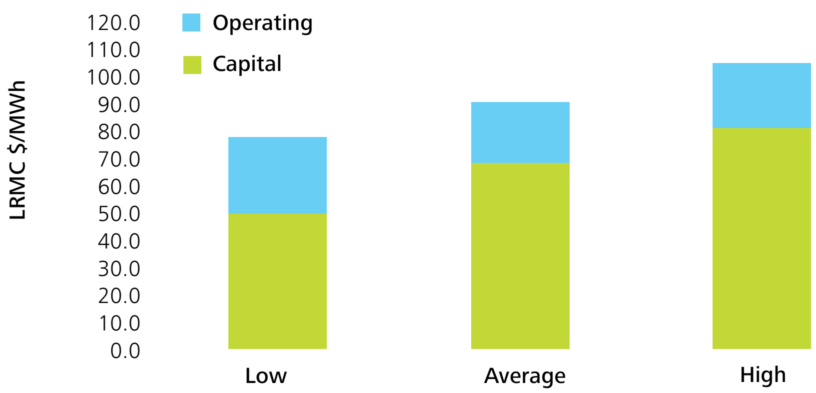
[1] Impact of exchange rate is included in capital cost as these costs are based in NZD

7.4 Raw LRMC for actual projects in NZ

Based on modelling actual operating projects in New Zealand we have established the following raw LRMC range. Included within these figures is the actual constructed cost[17] and the actual operating cost on a per MWh basis as provided to us by wind plant owners. The actual realised output in GWh and implied capacity factor are based on published output information and an average is applied to the available data points to determine a reasonable point estimate. While the GWh output is always likely to be subjective given the variable nature of wind, we have attempted to use the best available information sources to establish an appropriate average output for each of the wind farms modelled and where possible the data provided is based on correlations to long run data.

The results of the analysis based on this modelling reveals a range of LRMC between $78 and $105 per MWh for the representative projects.

LRMC – Raw constructed cost



7.5 LRMC adjusted for identifiable investment case factors

The modelling results above do not capture a number of other key investment drivers which are more difficult to quantify on a generic level but play a material part in the overall investment decisions made by developers. While there are a number of these drivers we have attempted to model the impact of the material ones where they are known for individual projects. The adjustments included in the LRMC figures presented in this section include adjustments for:

Avoided Transmission Revenue: Where wind farms are partially or fully embedded into the local distribution network the owner may receive revenue from the relevant lines companies as the embedded generator reduces the level of Transpower charges paid by the line company by helping to reduce the peak demand levels. More recently we understand avoided transmission revenue has increased significantly as a result of a change in Transpower's charging methodology. After 2007 Transpower began calculating transmission charges based on regional peaks rather than individual GXP peaks, and this has resulted in a step change in avoided transmission revenue.

For generic modelling purposes it is difficult to determine with accuracy the level of avoided transmission revenue however based on our understanding of the rates of revenue achieved by specific projects we are able to model these where they are relevant and received by the project.

GWAP / TWAP: Generation Weighted Average Price / Time Weighted Average Price or peaking factor relates to a plant's ability to capture greater than average wholesale prices and result from variability in generation volumes over time and wholesale price seasonality. This is discussed in section 5.1. Infratil recently released its own view of long term outlook for the New Zealand electricity market which outlines a view consistent with other market commentators views, including our own, that GWAP/TWAP is expected to fall to 90% or lower on strongly correlated sites[18]. We note that some investment cases already assume these discounts exist. Ultimately any decrease from a GWAP/TWAP ratio of 100% will result in a higher LRMC as the project is effectively receiving a discount to the average electricity price. It is difficult to determine the impact on a specific project basis and as a result for illustrative purposes we include a GWAP/TWAP factor of 95% and show the impact above the adjusted LRMC. The LRMC is highly sensitive to changes in GWAP/TWAP and this change alone can more than offset gains from other adjustments. >>

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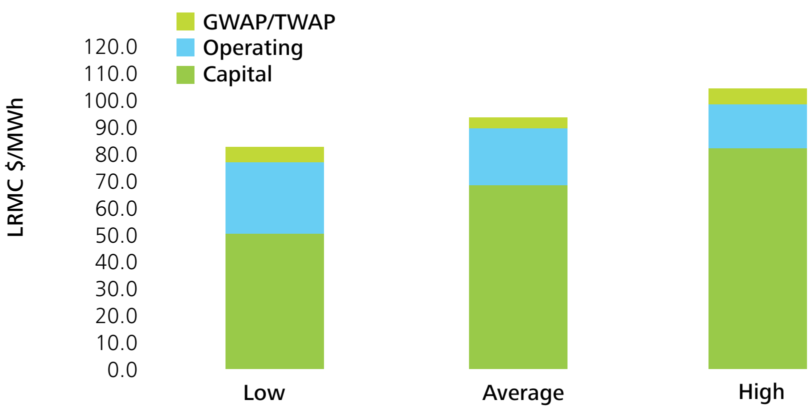
[17] We have made adjustments to historical capital costs to reflect an estimate of cost in $2010. The adjustment is subjective given the downward pressure on capital costs post 2008, however the impact of the adjustment on LRMC for the historical projects modelled is less than $3 per MWh.

[18] Source: Infratil, NZ Electricity Sector Long Term Outlook, Implications For Trustpower, Investor Day 2011.

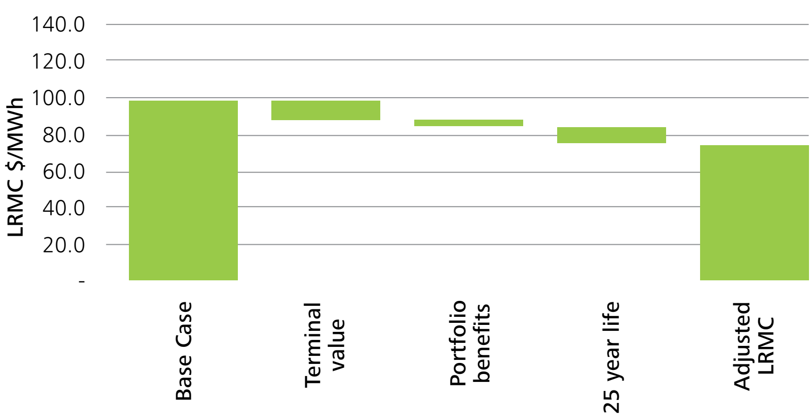
Carbon credits received from PRE scheme: As discussed in section 2.1 a number of the earlier constructed wind plants received carbon credits through the PRE scheme. We have adjusted the capital cost to reduce the upfront cost by the amount of potential sales proceeds (based on a $20 realised price). While there is more accurately a timing issue as the credits are earned over time, we believe the conservative price assumption for the Joint Initiative (JI) credits offsets this timing issue. As this adjustment is non-recurring for future projects we have calculated the impact separately and estimate the impact on LRMC of schemes awarded PRE credits to be between $4 and $8 per MWh.

We have not included the cost of firming and reserve capacity into this analysis. These are discussed further below and in Section 5.2 and 5.3.

LRMC – Adjusted for idenitifiable investment case factors



LRMC – Illustration of theoretical investment case adjustments



Ancillary services: The system operator typically contracts for ancillary services; these tend to be allocated to projects within an owner's portfolio after payment from the system owner. These major services are:

- Instantaneous Reserve. Instantaneous reserve or "spinning" reserve is necessary for the electricity system to provide immediate replacement generation in the event of a sudden unexpected shutdown of a generation unit. Instantaneous reserve costs are net of instantaneous reserve revenue received (if any) by offering reserve generation capacity.
- Transmission Event/Frequency Keeping (less rebate). Transmission event charges are penalties paid by plant for sudden unexpected shutdown of a generation unit. Transmission event charges included in the valuation are net of Transpower rebates (relating to transmission events caused by other generators).

7.6 Adjusted LRMC based on additional business case drivers

As discussed in section 6 there are a number of factors which investors in wind projects consider in their investment cases which are not captured in a simple LRMC analysis. We have analysed the approximate effect some of these factors may have by assessing their impact on the high end of the adjusted LRMC, the same principles could apply to projects with low LRMCs, reducing investment case LRMC further dependent on the specifics of the project concerned. The chart shows how material these investment case adjustments can be in determining the viability of a particular project for a particular investor. The example is illustrative only and in practice investors may choose to use more simple analysis or to apply some or all of these adjustments. There are a number of other adjustments however the ones shown below in our view have the most material impact on LRMC.

The analysis presented in the preceding sections demonstrates that for the representative sample of projects we have modelled LRMC for these projects has been between $78 - $105/MWh but for investment cases investors may view the projects as having significantly lower LRMC after adjusting for their own views on terminal value, economic life and portfolio benefits. There is some uncertainty with regard to the cost of firming capacity and the HVDC connection however investors may be able to optimise site specific conditions to minimise these costs where possible. >>

7.7 Sensitivity analysis

We have undertaken single point sensitivity analysis on key variables used in the analysis. The following table shows the impact of this sensitivity analysis on the LRMC of a theoretical project for movements in the key investment drivers. As discussed elsewhere in the report projects are highly sensitive to changes in project life, HVDC costs, GWAP/TWAP factors and changes in capital costs.

Sensitivity Analysis: Theoretical example LRMC = $92

Sensitivity	Change in LRMC	Base assumption
Increase life by 5 years then terminate	(6)	20 years
Phase out generation on straightline over 5 years	(2)	20 years
SI generation pays HVDC 25c pkWh	8	No HVDC
SI generation pays HVDC 40c pkWh	13	No HVDC
Nominal discount rate increase by 1%	6	10% post tax
Yield increases by 1%	(2)	40%
Location factor increase by 1%	(1)	97%
GWAP/TWAP 95%	5	100%
GWAP/TWAP 90%	10	100%
Capital cost + 10%	7	Low/average
Operating cost +10%	2	Low/average
NZD:EUR +/- 5 cents	*Not assessed*	*NZD costing*


Te Rere Hau

8. Comparison to other technologies

8.1. Alternative sources of generation

We have reviewed LRMC estimates from various sources and rebased these to $2010.

LRMC forecasts are a significant influencer of future investment decisions. Potential generation projects are filtered by investors according to their LRMC and committed only when wholesale electricity prices are expected to be sufficient to make them economically viable. Essentially the next project that proceeds should be the lowest cost initiative amongst the possible investment options. This comment holds in general however as discussed in section 6.1 LRMC is not the sole determinant of when one asset will be built over another.

The analysis indicates that geothermal is currently the lowest cost technology for electricity production in New Zealand. This is supported by the fact that several significant geothermal projects are currently under development or close to being commissioned around New Zealand, including Contact's 220MW[18]. Te Mihi facility near Taupo and both phases of its Tauhara project (263MW combined). Mighty River Power has also built the 132MW Nga Awa Purua station in Rotokawa, which was completed in 2010 and is investigating the commercial aspects of the proposed Ngatamariki Power Station. It is likely as the pool of undeveloped projects diminishes the LRMC of remaining projects will increase however it is difficult to determine at what point and how quickly this will occur.

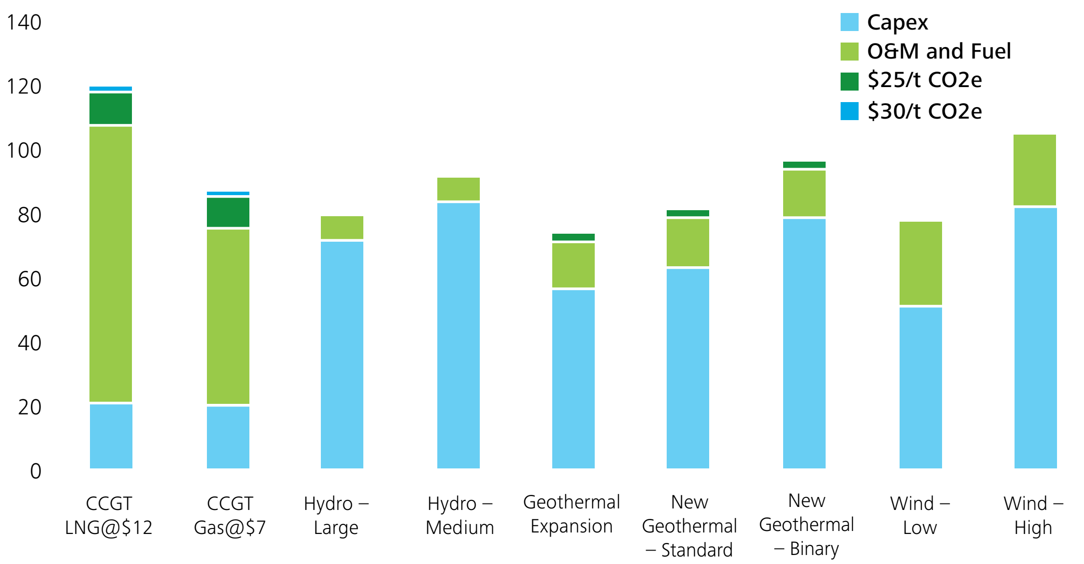
CCGT projects are considered viable at a gas price of around $7/GJ with a LRMC of approximately $85/MWh (based on a carbon price of $25/t CO2e). Gas prices are variable and the availability of contracted gas at economic prices will determine the relative LRMC of CCGT projects.

Until relatively recently gas combined cycle was considered to be the lowest cost technology with Otahuhu B, TCC and E3P all being constructed relatively recently at gas prices believed to be between $4/GJ and $7/GJ. Gas prices are believed to have increased sharply in recent years, reducing the attractiveness of gas fired generation versus the alternatives. Limited useful public information is available on the actual prices at which new gas contracts are transacted however.

Gas prices remain volatile with oil and gas exploration at historically high levels. New sources of gas such and new recovery techniques continue to be developed and have had a dramatic effect in reducing gas costs in markets such as the USA.

Against this background investment in wind, with its inherently high sunk capital cost and potentially high LRMC, which is project dependent, creates the risk of future returns from wind assets being below investment expectations should low cost gas or more extensive geothermal resources be developed. However in the event there is limited additional low LRMC geothermal development and if gas prices continue to rise the counterfactual may apply with wind becoming a more valuable portfolio asset.

LRMC – 2010$/MWh



Source: Meridian Energy, Deloitte analysis

Appendix 1

Constructed wind farms

Wind farm	Date operations	MW	Cummulative MW	PRE credits
Brooklyn	1993	0.2	0.2	No
Hau Nui II	1996	3.9	4.1	No
Tararua I	1999	31.7	35.8	No
Gebbies Pass	2003	0.5	36.3	No
Hau Nui II	2004	4.8	41.1	Yes
Tararua II	2004	36.3	77.4	Yes
Te Apiti	2004	90.8	168.1	Yes
Southbridge	2005	0.1	168.2	No
Te Rere Hau I	2006	2.5	170.7	Yes
Tararua III	2007	93.0	263.7	Yes
White Hill	2007	58.0	321.7	Yes
Te Rere Hau II	2009	32.5	354.2	Yes
West Wind	2009	142.6	496.8	No
Horseshoe Bend	2009	2.3	499.1	No
Weld Cone	2010	0.8	499.8	No
Te Rere Hau III	2011	9.0	508.8	No
Lulworth	2011	1.0	509.8	No
Te Uku	2011	64.4	574.2	No
Mahinerangi	2011	36.0	610.2	No
Total		**610.2**		

Source: NZWEA

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