

IN THE MATTER

of the Resource Management Act
1991

AND

IN THE MATTER

of applications to the **WAIKATO
DISTRICT COUNCIL** and
WAIKATO REGIONAL COUNCIL
by **WEL NETWORKS LTD** for
resource consents to authorise the
establishment, operation and
maintenance of 28 wind turbines for
the generation of electricity and
associated activities on the
Wharauoa Plateau near Te Uku

STATEMENT OF EVIDENCE OF JIM TRUESDALE

1. INTRODUCTION

Qualifications and experience

- 1.1 My name is Jim Truesdale. I am a director of Concept Consulting Group, a Wellington based consultancy specialising in the energy sector.
- 1.2 I hold a Bachelor of Electrical Engineering degree (honours, 1979) and a Master of Electrical Engineering degree (1981), both from the University of Canterbury.
- 1.3 I specialise in electricity generation and wholesale electricity market issues. Prior to the establishment of Concept Consulting Group in 1999, I worked for over twenty years in the electricity sector in engineering, operational and senior executive roles.
- 1.4 Experience which is relevant to my evidence includes:
 - (a) Co-ordinating New Zealand's electricity generation resources (as Generation Control Manager at ECNZ¹).
 - (b) Establishing and overseeing electricity market operation and trading (as Wholesale Market Development Manager at ECNZ and establishment General Manager Operations and Trading at Genesis Power).

¹ Electricity Corporation of New Zealand.

- (c) Developing and reviewing electricity market arrangements in NZ and overseas.
- (d) Providing advice on security of supply issues, including to the Ministry of Economic Development and the New Zealand Electricity Commission.
- (e) Undertaking technical and economic analysis of electricity markets, including longer term electricity supply and demand projections, security of supply risk assessments, evaluation of power station development options and assessing climate change policy implications.
- (f) Advising on issues relating to climate change policy, on likely greenhouse gas emission reductions associated with proposed renewable energy developments, implications for New Zealand's Kyoto Protocol commitments and carbon related impacts on future electricity prices.

Purpose and scope of my evidence

1.5 The purpose of my statement is to:

- (a) Provide an overview of the New Zealand electricity market within which decisions to build and operate electricity generation projects are made by investors (section 3);
- (b) Discuss how the cost of carbon flows through the electricity value chain, affecting different electricity generation resources and electricity prices (section 4); and
- (c) Discuss factors affecting the carbon footprint of the Te Uku project and its potential impact on New Zealand's greenhouse gas emissions (section 5).

1.6 In covering the above points I shall also comment on some of the assertions made by Mr Gallagher and Mr Cox in their statements and, particularly, substantive inconsistencies and errors relating to Mr Cox's assertion that the carbon payback period for the Te Uku wind farm project would be 7.8 years.

Expert Witness Code of Conduct

1.7 I have been provided with a copy of the Code of Conduct for Expert Witnesses contained in the Environment Court's Consolidated Practice Note 2006 [2006] NZRMA 357. I have read and agree to comply with that Code. This evidence is within my area of expertise, except where I state that I am relying upon the

specified evidence of another person. I have not omitted to consider material facts known to me that might alter or detract from the opinions that I express.

2. SUMMARY OF EVIDENCE

- 2.1 The New Zealand electricity market enables generators across the country to compete to supply consumer demand within a framework which promotes economic efficiency. It also disciplines commercial decision-making – investors must be satisfied that a new generation project will earn sufficient revenues to make a commercial return on all costs over the life of the project. I stress this point because Mr Cox’s claims that certain generation options are more economic than others are not supported by investment decisions being made in the electricity market².
- 2.2 Generation revenues will be affected by the amount of electricity generated and wholesale market prices at the time. These factors will depend on climatic conditions, consumer demand, transmission system capability and the availability, location and relative costs of competing generation options. Some generators also earn secondary revenue from ancillary services (such as maintaining power system frequency or supporting voltage on the transmission system). Being able to increase production when market prices are higher and vice versa, controllable generation will tend to receive a higher average price³ for its output than generation that is uncontrollable (at the same location).
- 2.3 In addition to financing, building, operating and maintaining generation plant, an investor also faces costs for connecting to the power system and participating in the electricity market. Costs can be fixed (incurred whether the plant generates or not) or variable (incurred only when the plant generates).
- 2.4 Once built, the variable operating costs of a generation facility determine its ability to compete with other generation in the market. Facilities with low variable operating costs, such as wind, must run hydro⁴ or geothermal generation, can be offered into the market at zero or very low prices. The market will dispatch this generation ahead of generation with higher variable operating costs, such as fossil-fuelled thermal power stations⁵ or hydro schemes with limited storage⁶.

² Renewable generation investments that have been made in the last few years and are likely in the next few years are largely limited to wind and geothermal developments.

³ Both generation sources at the same location would receive the same market price for each unit of production but market revenue divided by electricity generation over a given period will be different.

⁴ Hydro schemes with minimal ability to storage water.

⁵ In particular fuel costs.

- 2.5 Under the emissions trading regime being developed as part of Government's climate change policy, fossil-fuelled thermal generators will face a carbon price on all emissions, thus increasing their variable operating costs. This will have flow-on effects to electricity market prices, making renewable energy options such as wind farms more attractive to investors. Once built, renewable supply options with low variable operating costs will be able to displace fossil-fuelled thermal generation in the market and avoid associated greenhouse gas emissions.
- 2.6 The extent to which an individual wind farm investment will avoid emissions from fossil-fuelled thermal power stations is difficult to assess. It could be argued that the 10 year moratorium on new base-load fossil-fuelled thermal power stations⁷, rather than any individual renewable generation project, will avoid emissions from new thermal power stations. If a particular renewable energy project is unable to proceed, under the moratorium an alternative renewable generation project, even if more expensive, could theoretically take its place.
- 2.7 It is possible to assess the impact of a particular renewable generation project on emissions from existing thermal power stations. New renewable generation with total costs less than the variable operating cost of existing thermal stations, including the cost of carbon, would be commercially viable. Once built, a renewable generation project could avoid emissions from existing fossil-fuelled power stations since it is likely to be offered into the market at a relatively low price and displace higher variable cost thermal generation. However, assessing the likely impact is difficult.
- 2.8 New Zealand's thermal power station mix includes combined cycle gas turbines (CCGT) and coal-fired steam plant⁸ with estimated emission factors of approximately 370 and 930 tonnes respectively of carbon dioxide per GWh of electricity generated. Depending on prevailing market conditions (such as hydro inflows, fuel contracts and demand) at any time a mix of coal and gas-fired plant,

⁶ (Variable) opportunity costs of releasing stored water now for generation or storing the water for later use (trading off the cost of replacement generation, running out or spilling in future).

⁷ To be implemented through "The Emissions Trading Scheme and Renewables Preference Bill", introduced in December 2007. The Bill allows exemptions to be granted where new fossil-fuelled plant is required to ensure security of supply, and/or where new plant is replacing older fossil-fuelled plant, and the replacement plant will lower emissions without reducing security margins. How these criteria are to be applied in practice has yet to be clarified.

⁸ Until recently, the thermal supply mix included gas fired steam plant at Huntly Power Station (designed to operate on gas and coal, but now largely coal-fired) and New Plymouth Power Station (gas or oil fired but recently retired). The mix also includes a small amount of cogeneration (which tend to operate according to the host site's steam/heat demand and is less responsive to electricity market prices) and oil and/ or gas fired open cycle gas turbine (OCGT) plants.

and potentially hydro at times of high inflows, would be displaced by a new wind farm. Displacement is difficult to predict because of the many variables involved, but it is unlikely to be as high as 930 tonnes per GWh or to be substantially less than 370 tonnes per GWh (except during periods of high hydro inflows). If, on average, one GWh of new renewable generation would evenly displace gas-fired CCGT and coal-fired⁹ steam generation, then approximately 650 tonnes of carbon dioxide equivalent emissions would be avoided¹⁰.

- 2.9 At the above rate, the Te Uku project could avoid up to 168,000 tonnes of carbon dioxide emissions annually (assuming an average contribution of 259 GWh to annual energy supply requirements). The development of other renewable projects could have the effect of reducing the avoided emissions from Te Uku. However, as demand grows the contribution from new renewable supply projects will be consumed, existing thermal plant will again become competitive and will increase production levels and emissions. The period over which this occurs will depend on the volume of competitive new renewable supply options available¹¹ relative to existing thermal supply and the rate of demand growth.
- 2.10 While it is difficult to estimate the level of emission reductions that would result from the Te Uku project, it is important to note that it would contribute to Government's climate change objectives, assisting the moratorium, and that it could make an initial contribution to reducing carbon dioxide emissions up to 168,000 tonnes per annum, depending on the extent to which other new renewable generation projects are developed contemporaneously, and in the future, to meet demand growth.
- 2.11 Given the above issues, the carbon payback period¹² for a specific wind farm project is also difficult to estimate. However, a conservative upper estimate of approximately 104,000 tonnes of carbon dioxide equivalent for the carbon footprint¹³ of the Te Uku wind farm indicates a payback period of less than 7.5 months assuming an initial emission avoidance rate of 168,000 tonnes per annum. In contrast, Mr Cox asserts a payback period of 7.8 years.

⁹ Possibly a conservative assumption given greater variable operating costs (including carbon costs) of coal-fired generation.

¹⁰ This is similar to the emission factor published in a study for the Ministry of Environment in 2003. However, that study was carried out to consider the impact of smaller renewable projects over the period 2008-2012 and was undertaken before the introduction of the moratorium.

¹¹ The market will determine an economic limit on new renewable supply - to the extent that substantial amounts impose additional system operating costs, the owners will face a share of those costs.

¹² The period of time it would take to displace thermal generation emissions equal to the amount of emissions associated with its manufacture, construction and operation.

- 2.12 Mr Cox assumes that the Te Uku wind farm would produce 132.4 GWh of electricity annually. As explained by Mr Burchett, the Te Uku project is expected on average to produce 259 GWh of electricity annually, roughly double Mr Cox's assumption. Substituting the correct annual energy output figure into Mr Cox's calculations, but accepting his other assumptions at face value, would reduce his estimate of the payback period from 7.8 years to just under 4 years.
- 2.13 Further, Mr Cox states that displacement of other generation by the Te Uku project would be apportioned between gas (50%), thermal (30%) and hydro (20%). I assume by 'thermal' he means coal-fired steam plant¹⁴. He then asserts that this represents an overall emission displacement factor of 0.1 tonnes per MWh (100 tonnes per GWh). Combining the displacement proportions assumed by Mr Cox with the emission factors I have used (as in paragraph 2.8), yields an overall emission factor of approximately 460 tonnes per GWh. Applying this corrected figure to Mr Cox's calculations would further reduce his estimate of the payback period to approximately 10.5 months. This is not dissimilar to my estimate of 7.5 months.
- 2.14 Other basic errors made by Mr Cox further undermine put into question the credibility of his statement. For example, as noted above, he uses a very low factor of 0.1 tonnes per MWh for estimating emissions that would be avoided by the Te Uku project. Instead of using this factor, he then uses an apparently arbitrary figure of 0.4 tonnes per MWh for his alternative generation options. This inconsistency biases his estimates of emissions reductions by 400% in favour of his alternative generation options.
- 2.15 Some assertions in his statement also suggest Mr Cox does not understand how the New Zealand electricity market works. For example, he asserts that "*new rules coming into force will prohibit the bidding of more than 90% of maximum output from wind turbines without cogeneration*". This may have been lifted, or misinterpreted, from another jurisdiction (perhaps Denmark¹⁵) but has no relevance to New Zealand electricity market arrangements. He also appears to believe that wind generators

¹³ The volume of carbon emissions that would be produced in the lifecycle of the wind farm including during manufacture, construction, operation and decommissioning.

¹⁴ Fossil-fuelled plant in general (coal, gas, oil), not just coal-fired plant, is classified as thermal generation.

¹⁵ I say this because Denmark has relatively high levels of wind generation and cogeneration. Unlike New Zealand, it has negligible hydro generation but relies on transmission links with other countries (for example, Norway) for flexible supply.

receive payments for quantities offered (he uses the term *bid*) into the market¹⁶. In fact, market payments to wind generators are made for actual generation.

2.16 I make some additional comments on the statements by Mr Cox, and also some comments by Mr Gallagher, in the body of my statement.

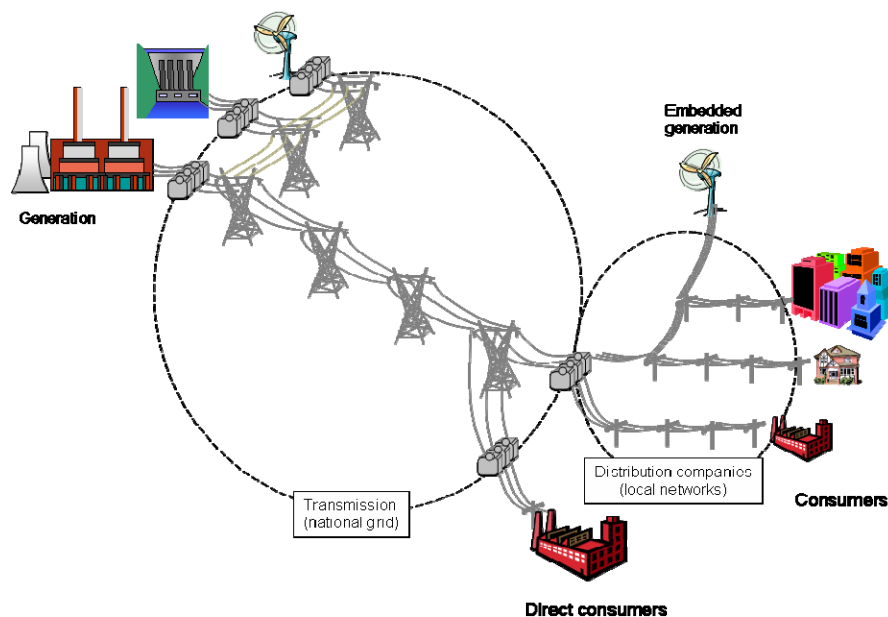
3. **ELECTRICITY MARKET OVERVIEW**

3.1 In this section I will provide a brief outline of the electricity market structure and operation to explain the commercial environment within which market participants make decisions.

Physical arrangements

3.2 Figure 1 illustrates the key physical elements of the national electricity supply system.

Figure 1: Power System Layout



3.3 In relation to Figure 1:

(a) Approximately 42,000 GWh¹⁷ of electricity generation¹⁸ is currently required to meet New Zealand's annual electricity demand.

¹⁶ For example, he makes statements like "*The fundamental is not what you can produce but what you can sell*" and "*To estimate bid power it has been assumed that WEL will be able to predict wind well enough to achieve a level of 94% of actual following hour minimum*".

- (b) The national transmission grid, owned and operated by Transpower, is the backbone of the electricity supply system enabling electricity supply and demand to be matched continuously across the country.
- (c) The national grid transports approximately 40,000 GWh from power stations around the country to over 25 local distribution companies, such as WEL Networks in the Waikato region, and a small number of large grid-connected consumers¹⁹.
- (d) Distribution companies deliver electricity to consumers connected to their networks.
- (e) A small proportion of electricity, approximately 5%, is supplied by generation embedded within distribution company networks, as proposed for the Te Uku wind farm project.
- (f) Some electricity generation is dissipated as losses as it travels from power stations through the transmission and distribution networks to consumers. In 2006 this amounted to approximately 7.5% of total supply²⁰.

Commercial overview

- 3.4 The New Zealand electricity market is structured along the lines shown in Figure 2 and underpinned by the physical arrangements outlined above. There are competitive wholesale and retail markets.

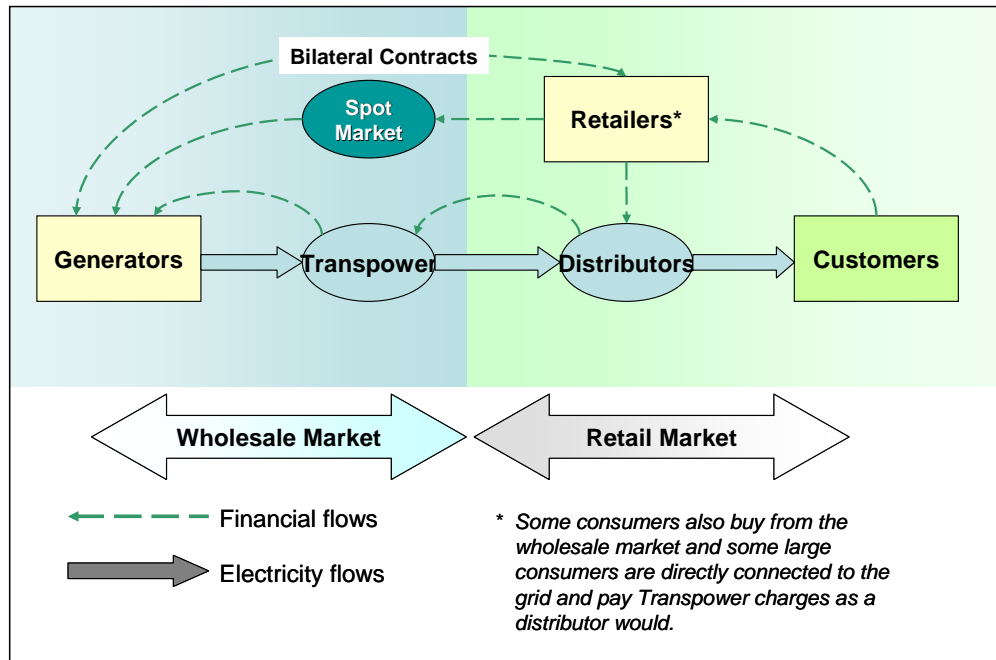
¹⁷ *Gigawatt hour* - a typical New Zealand household uses less than one hundredth of a GWh of electricity annually.

¹⁸ Sourced from "New Zealand Energy Data File, June 2007", Ministry of Economic Development.

¹⁹ For example, the BHP NZ Steel site at Glenbrook and the Rio Tinto aluminium smelter at Tiwai.

²⁰ For year ended 31 March 2006 ("New Zealand Energy Data File", June 2007; Ministry of Economic Development).

Figure 2: Commercial Structure



- 3.5 The wholesale market is a combination of half hourly spot and longer term contracts markets. Prices in the wholesale electricity market, in which generators compete to supply demand, are set every half hour and vary considerably with demand patterns and generation conditions. Retail prices are set by retailers but consumers are free to switch between suppliers. Retail prices are typically fixed but over the medium term follow trends in wholesale market prices. My statement largely focuses on the wholesale market but the longer term relationship between wholesale and retail market prices over time is an important discipline on market participants and investors.
- 3.6 Physics dictate that electricity generation must be coordinated continuously across the country to ensure that supply at all times matches consumer demand. This is coordinated across the national grid by Transpower, as system operator, in accordance with a set of spot market rules²¹.

Spot market basics

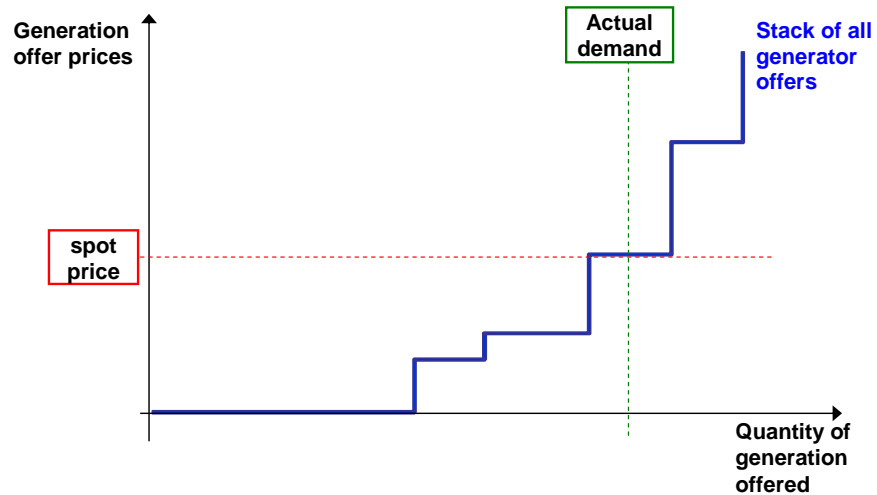
- 3.7 In the spot market, generators submit half hourly offers for the amount of electricity they are prepared to sell at specified prices²². Offer prices determine which generation is dispatched by the system operator to meet demand. As demand rises, increasingly higher priced generation is used and vice versa.

²¹ Part of the Electricity Governance Regulations (EGRs) administered by the Electricity Commission.

²² Offers are submitted for each generating unit for each half hour up to midnight of the following day.

- 3.8 Figure 3 shows, in stylised form, how the generation needed to match the next increase or decrease in demand sets the spot market price for a particular half hour²³.

Figure 3: Spot market pricing



- 3.9 For each half hour, generators are paid the spot price for electricity they were instructed to produce and retailers and direct consumers pay the spot market clearing price for electricity they purchased²⁴.
- 3.10 The spot market is an efficient way of:
- (a) Coordinating moment to moment physical supply to maintain system security; and
 - (b) Ensuring that generators with very low variable operating costs are able to operate ahead of other generation with higher operating costs.
- 3.11 In relation to the last point:
- (a) Geothermal, wind and must run hydro²⁵ can be offered into the spot market at very low prices (reflecting very low variable operating costs²⁶).

²³ In practice, arrangements are more complex than depicted and the price is set after the event (ex post) based on final generator offers and half-hourly metered demand.

²⁴ Financial settlements occur in the following month.

²⁵ Hydro power stations which have little storage capacity and can generate only when inflows are available.

²⁶ In other words most of the costs are fixed and will be incurred each year whether the plant generates or not.

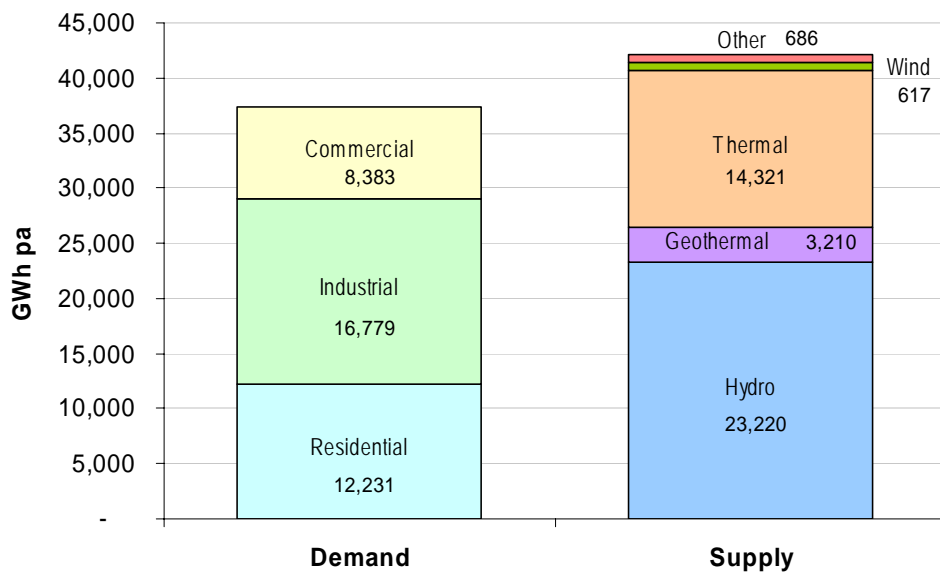
- (b) Discretionary hydro²⁷ can be offered into the market reflecting the future risks (opportunity cost) of running out of water or over-filling and having to spill (waste) water.
 - (c) Fossil-fuelled thermal power station offer prices reflect higher variable operating costs, in particular fuel costs.
- 3.12 In line with Government's overall efficiency objectives for electricity supply, the electricity market rules play an important role in enabling such trade-offs to occur.
- 3.13 In dispatching generation around the country to minimise the overall cost of supplying demand, the wholesale market takes transmission losses and constraints into account. This means that separate prices are established each half hour at over 200 locations around the country, reflecting the cost of transporting electricity around the country. While proximity to thermal fuel, wind, geothermal and hydro resources will clearly influence new generation investment decisions, locational pricing also sends important longer-term signals to investors about where and when new supply and/ or transmission investments would reduce losses or avoid investment in the grid. Prices nearer major load centres are typically higher than prices at remote generation locations – this provides an important signal that it is efficient to locate generation close to demand.

Supply and demand

- 3.14 Figure 4 shows, for the 2006 calendar year, the amount of electricity used by different types of consumers (demand) and the amount of electricity produced (supply) by different generation technologies.

²⁷ Hydro systems with storage lakes provide some discretion as to when water is released from storage or held in storage for future use.

Figure 4: Electricity Demand Supply Mix 2006²⁸



- 3.15 The difference between total supply and total consumer demand in Figure 4 shows that in 2006 approximately 11% of electricity generation was consumed as losses, a large portion due to transmission and distribution system losses²⁹. Losses would be minimised if electricity could be generated where it is needed. However, in practice, decisions about where to build power stations are influenced by the location of natural resources, such as rivers, wind patterns or geothermal fields, the cost of transporting fuel (such as coal or gas) and the cost of transporting electricity to where it is needed.
- 3.16 As discussed previously, locational pricing arrangements in the electricity market fill an important role in signalling the relative benefits or costs of competing electricity supply options including transmission losses and constraints.

Supply mix

- 3.17 Returning to the supply mix, the New Zealand electricity system has a large proportion of hydro supply. This is in contrast to many overseas jurisdictions, which are often dominated by thermal power stations. This means that the New Zealand electricity system has significant short term supply flexibility, because hydro power stations can vary electricity production quickly and start-up and shut-down faster

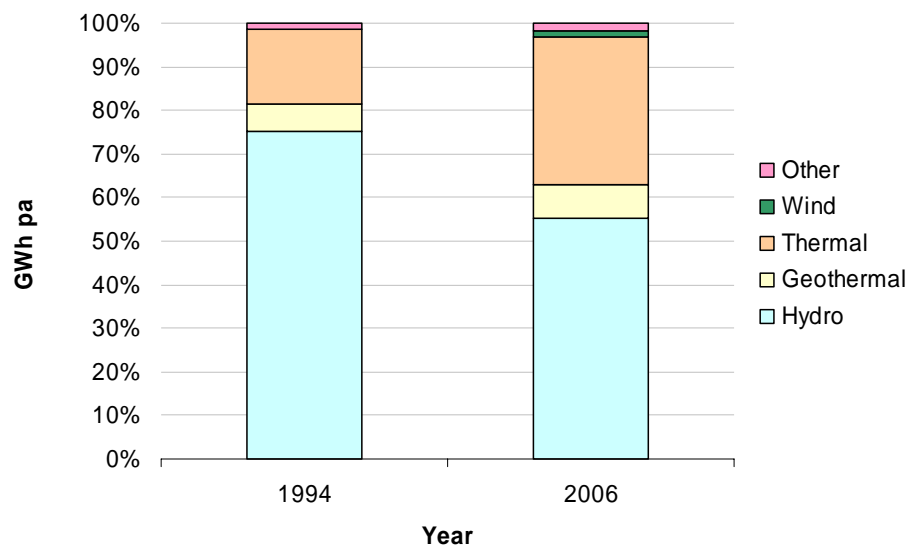
²⁸ Data sourced from “New Zealand Energy Data File, June 2007, Ministry of Economic Development”.

²⁹ Some of these losses occur at electricity generation facilities (as electricity used on site for auxiliary requirements). As noted previously, transmission and distribution loss are approximately 7.5%.

than thermal power stations. This capability can help to reduce the impact of shorter term variations in demand and supply (for example, variations in wind generation).

3.18 To a lesser extent, thermal power stations also make a significant contribution to New Zealand’s electricity requirements. As shown in Figure 5, much of the increase in electricity demand since 1994 has been met by fossil-fuelled thermal power stations. The Clyde dam, the last major hydro development, was completed in 1993.

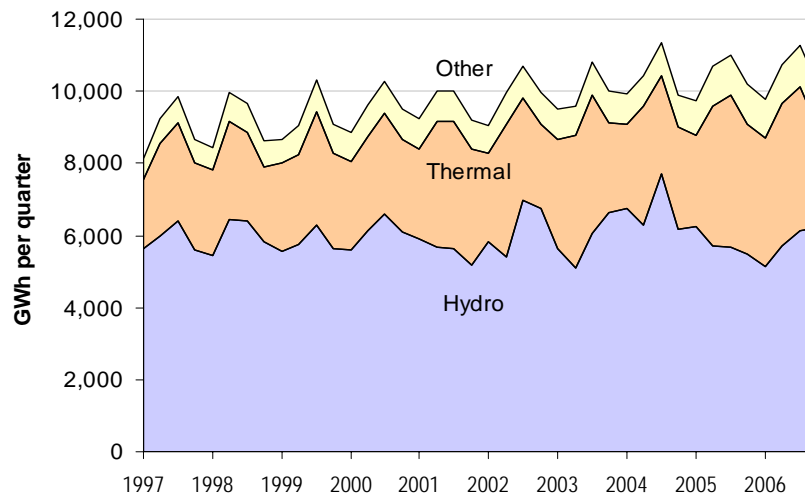
Figure 5: Change in the Mix of Electricity Produced - 1994 to 2006³⁰



3.19 While hydro power stations provide significant short term (hour to hour) supply flexibility, longer term energy supply variations can be large. To illustrate this point, Figure 6 shows how quarterly hydro generation varied over the period 1997 to 2006.

³⁰ Data sourced from “New Zealand Energy Data File, June 2007”, Ministry of Economic Development.

Figure 6: Quarterly Supply Mix 1997 to 2006³¹



- 3.20 The hydro storage lakes can be used to smooth out some of the seasonal fluctuations in weather dependent hydro inflows. However, storage capacity is limited³² and as illustrated in Figure 6, thermal power stations also fill an important role in compensating for seasonal hydro variability. During hydro droughts, fossil-fuelled thermal power stations have been vital to maintaining security of energy supply.

Energy constrained system

- 3.21 The New Zealand electricity system has therefore been characterised as *energy constrained* – having technical generating capacity (installed MW) in excess of peak demand but limited ability to generate for prolonged periods because of hydro energy constraints. In this sense, New Zealand security of electricity supply issues have been dominated by seasonal hydro energy (GWh) concerns rather than short term generating capacity (MW) concerns.

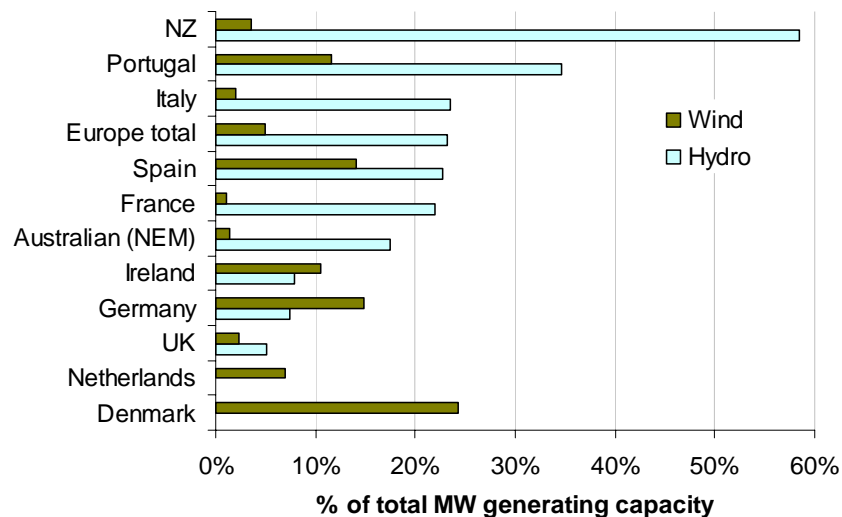
Future outlook

- 3.22 Looking forward, there is an increasing focus on renewable energy supply options to reduce greenhouse gas emissions. As part of its overall energy strategy, Government has decided to introduce an emissions trading regime and to place a moratorium on the development of new base load fossil-fuelled thermal power stations for ten years. Security of energy supply will clearly depend on existing fossil-fuelled thermal power stations to some extent but adding other forms of energy supply to the system will help to increase diversity and energy security.

³¹ Data sourced from “New Zealand Energy Data File, June 2007”, Ministry of Economic

3.23 While able to contribute to energy supply requirements, wind generation can be difficult to predict over the shorter term. Concerns have therefore been raised about the potential implications for short term security of supply if large levels of wind generation were to be added to the New Zealand electricity system. Compared to many other countries, New Zealand has large amounts of hydro with short term flexibility which should help to offset wind variability. Figure 7 compares the amount of hydro and wind generation as a proportion of total generating capacity for a number of countries³³. In Europe, Denmark, Germany, Spain, Portugal and Ireland have relatively large levels of wind generation – each of which has significantly lower proportions of hydro generating capacity.

Figure 7: Hydro and wind generating capacity comparisons



3.24 There are of course a range of factors which influence the technical ability, and cost, of electricity systems to accommodate wind generation and such comparisons should be made with caution. As in other countries, it is reasonable to assume that with increasing wind generation development, the New Zealand electricity system can be expected to bear additional costs to maintain security.

3.25 The Electricity Commission is currently considering how to efficiently integrate wind generation into the electricity market³⁴. Importantly, its framework for considering options includes the principle that wind generation investors face the costs they impose on the system³⁵. The market already allocates system costs in this manner.

Development.

³² Around 5 weeks of winter demand when the hydro storage lakes are full.

³³ European data sourced from Euroelectric.

³⁴ "Wind Generation Investigation Project, Discussion Paper on Initial Options Assessment", 18 October 2007, Electricity Commission.

³⁵ This principle is already evident in the market rules. For example, the costs of ancillary services are allocated to the parties causing the need.

For example, because of their size³⁶, thermal generating units face a large share of the cost of instantaneous reserves³⁷. Wind generation investors, as for generation investors generally, will need to factor any system costs they will bear into their decision-making.

- 3.26 Also, the generation weighted average price³⁸ a wind generator receives for its generation will tend to be lower than that received by controllable generation with the ability to increase production when market prices are high and vice versa. As the level of wind generation grows, market prices can be expected to become more volatile, with the market rewarding more flexible controllable generating capacity, such as hydro generation with storage or fast start thermal generation.
- 3.27 Except for the moratorium on new fossil-fuelled thermal power stations, the electricity market arrangements I have discussed will determine the future mix of generation options by signalling the value and cost of different forms of generation and imposing commercial disciplines on generation investors. Carbon costs, which I will now discuss, will also have a significant influence in determining the future generation mix.

4. **CARBON AND ELECTRICITY MARKET INTERACTIONS**

- 4.1 In this section I will explain how the cost of carbon can be expected to flow through the electricity market and the implications that will have for the operation of the market and new investment decisions. This will also provide a context for discussing and correcting assertions made by Mr Cox regarding carbon abatement in the form of emissions reduction.

Background

- 4.2 Under the Government's proposed emissions trading regime, described by Mr Palakshappa in his statement, fossil-fuelled thermal generators will receive a zero allocation of emission rights. They will in effect have to pay a carbon price for all emissions. These costs will flow through the electricity market with implications for the operation of the market, generator investment decisions and electricity prices.

³⁶ Up to approximately 400 MW.

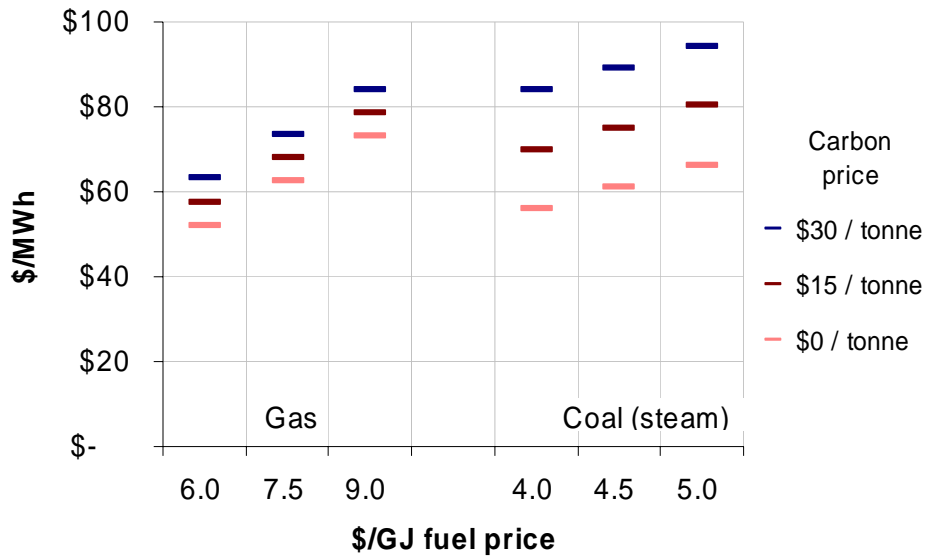
³⁷ For example, the market procures instantaneous reserves (contracts for partly loaded generation and interruptible load) to cover the failure of a large generating unit or Cook Strait transmission. The half hourly procurement costs are allocated proportionately to such risks on the system at the time above 60 MW, with an increased proportion to assets that actually fail.

³⁸ Market revenue divided by electricity sold.

Impacts on generation costs

- 4.3 Figure 8 indicates how the variable operating costs of CCGT and coal-fired thermal power stations will be affected by the cost of emissions for a range of carbon and fuel costs³⁹. For a given price of carbon, carbon costs will be greater for coal generation reflecting lower plant efficiency and higher carbon loadings in the fuel.

Figure 8: Impact of carbon cost on fossil-fuelled generation variable costs



- 4.4 By comparison, renewable generation has low variable costs and will generally not face carbon costs⁴⁰.

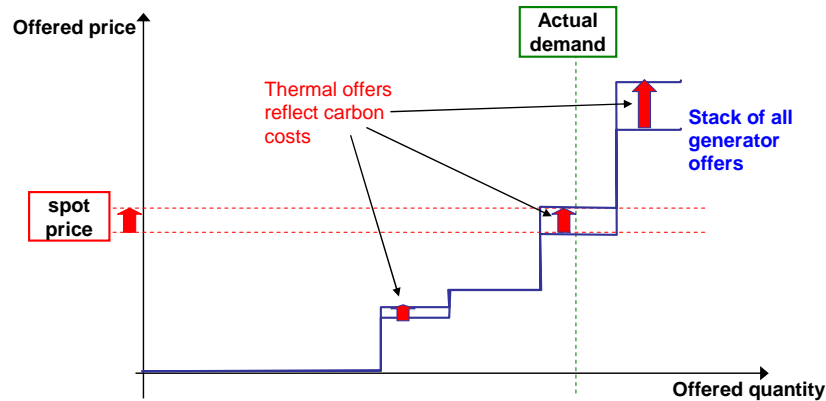
Market impacts

- 4.5 From an operational perspective, thermal generator offer prices can be expected to increase reflecting higher variable operating costs due to the cost of carbon. This will tend to cause wholesale market prices to rise, depending on the need for thermal generation at the time, as depicted in stylised form in Figure 9. In practice, offers will vary by half hour and from day to day depending on the availability and/ or cost of generation resources.

³⁹ CCGT and coal-steam heat rates are assumed to be 7,000 GJ/GWh and 10,250 GJ/GWh respectively. The carbon content of coal and natural gas are assumed to be 52.3 and 91.2 kt per PJ respectively (“New Zealand Energy Greenhouse Gas Emissions, 1990–2005”, June 2006 Ministry of Economic Development). Variable non fuel operating costs for CCGT and coal plants are assumed to be \$10 and \$15 per MWh respectively.

⁴⁰ Geothermal generation will also face some carbon costs although much smaller than for fossil-fuelled generation.

Figure 9: Stylised impact of carbon costs on thermal offers and market prices



- 4.6 If this were to occur tomorrow, it is unlikely to have any material effect on the amount of existing lower cost must run generation because that is largely determined by maintenance requirements and the availability of resources such as water, wind and geothermal fluids. However, with carbon costs causing electricity prices to rise, the range of commercially renewable generation investments will be expanded. The moratorium on new thermal development will expand this range.

Implications for emissions

- 4.7 Once built, renewable generation with low variable operating costs can be offered into the market at lower prices thus displacing thermal generation and avoiding associated emissions that would otherwise occur. The actual level of emissions that would be avoided is difficult to estimate, depending on a range of market factors at the time, for example, electricity demand, thermal fuel contracts, plant maintenance, hydro and wind supply availability and transmission system availability. The level of avoided emissions attributable to a particular renewable project is also difficult to assess, depending on the relative costs of competing renewable options and variable operating costs of existing thermal generation.
- 4.8 The removal of new base load thermal generation options from the market, under the 10 year moratorium, means that some otherwise uneconomic renewable generation projects will become commercially viable. While the objective of the moratorium is clearly to promote renewable generation development and avoid thermal emissions, it is now more difficult to argue that a particular renewable project will reduce emissions because, theoretically, alternative (even if more costly) renewable options could take its place if it is unable to proceed.

- 4.9 Given low variable operating costs, a new renewable generation project will avoid emissions by being dispatched in the market ahead of existing thermal generation. New Zealand's thermal power station mix includes combined cycle gas turbines (CCGT) and coal-fired steam plant with estimated emission factors of approximately 370 and 930 tonnes respectively of carbon dioxide per GWh of electricity generated⁴¹. Depending on prevailing market conditions, such as hydro inflows, fuel contracts, transmission availability and demand, at any time a mix of coal and gas-fired plant (and potentially hydro at times of high inflows) would be displaced.
- 4.10 Expected displacement is difficult to predict because of the many variables involved. However, the rate of emissions avoided is unlikely to be as high as 930 tonnes per GWh or substantially less than 370 tonnes per GWh (except during periods of high hydro inflows). If, on average, one GWh of new renewable generation would evenly displace gas-fired CCGT and coal-fired⁴² steam generation, approximately 650 tonnes of carbon dioxide equivalent emissions would be avoided⁴³.
- 4.11 At the above rate, the Te Uku project could avoid up to 168,000 tonnes of carbon dioxide emissions annually (assuming an average contribution of 259 GWh to annual energy supply requirements).
- 4.12 At this point, I note that Mr Cox has assumed in his statement that displacement of generation by renewable generation would be apportioned between gas (50%), thermal (30%) and hydro (20%)⁴⁴. He then concludes that this represents an overall emission factor of 0.1 tonnes per MWh (100 tonnes per GWh). Had he used correct emission factors (as in paragraph 2.8), he would have calculated an overall emission factor of 0.464 tonnes per MWh (464 tonnes per GWh).
- 4.13 Once lower cost new renewable supply options have been developed, existing thermal plant would again be competitive and increase production with demand growth. The period over which this occurs will depend on the volume of competitive

⁴¹ Based on carbon loadings for natural gas and coal of 52.3 and 91.2 kt/ PJ ("New Zealand Energy Greenhouse Gas Emissions, 1990–2005", June 2006 Ministry of Economic Development) and CCGT and coal-steam generation heat rates of 7,000 and 10,250 GJ/GWh respectively.

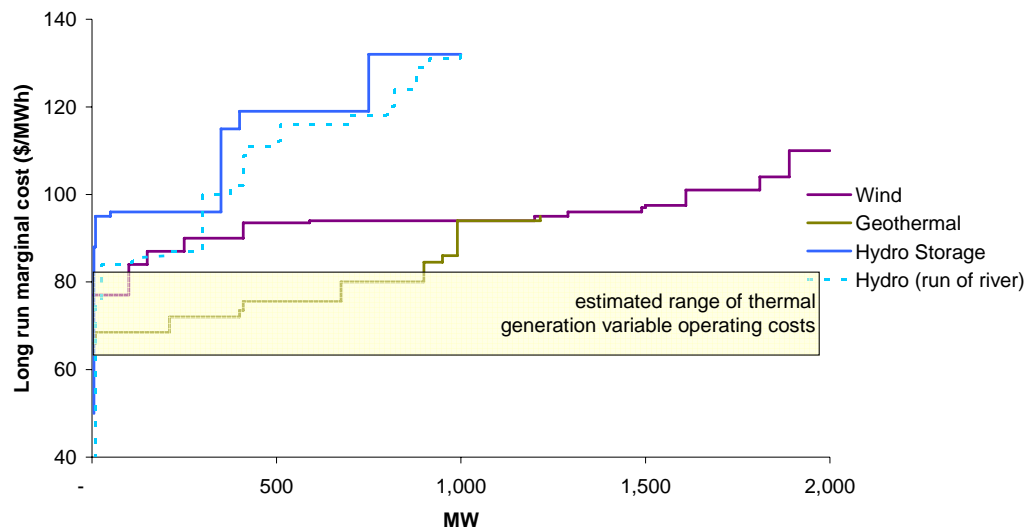
⁴² Possibly a conservative assumption given greater variable operating costs (including carbon costs) of coal-fired generation.

⁴³ This is similar to the emission factor published in a study for the Ministry of Environment in 2003. However, that study was carried out to consider the impact of smaller renewable projects over the period 2008-2012 and was undertaken before the introduction of the moratorium.

⁴⁴ Under industry convention, fossil-fuelled plant in general (oil, gas, coal) is classified as thermal generation but I assume Mr Cox uses the term 'thermal' to mean coal-fired steam plant.

new renewable supply options available⁴⁵ relative to existing thermal supply and the rate of demand growth. In this regard, Figure 10 compares estimates of renewable generation development options, derived from a Government New Zealand Energy Strategy publication⁴⁶, to the estimated range of variable operating costs for existing thermal generation including carbon costs.

Figure 10: Total costs of renewable supply developments vs existing thermal variable operating costs



4.14 While it is difficult to estimate the level of emission reductions that would be attributable specifically to Te Uku project, it is important to note that:

- (a) The Te Uku project would contribute to Government’s climate change and energy strategy objectives, and assist the moratorium.
- (b) Substantial renewable generation development will be required for Government to meet its policy objective that 90% of electricity supply be from renewable sources by 2025. Government expects annual electricity demand to be approximately 11,000 GWh higher in 2025 than now, of which the Te Uku project would supply 259 GWh, or less than 2.5%. If long term historical growth rates were to continue⁴⁷, annual demand in 2025 would be substantially higher, approximately 18,000 GWh higher than now. It would

⁴⁵ The market will determine an economic limit on new renewable supply - to the extent that substantial amounts impose additional system operating costs, the owners will face a share of those costs.

⁴⁶ “New Zealand Energy Strategy to 2050”, November 2007.

⁴⁷ Around 2% per annum since 1980.

take many projects of the size of the Te Uku project to meet this increase in demand.

- (c) On its own, the Te Uku project would make an initial contribution to reducing carbon dioxide emissions of 168,000 tonnes per annum, but that figure may be smaller depending how the mix of generation development alters over time.

5. CARBON FOOTPRINT

- 5.1 In relation to a wind farm development, a carbon footprint represents the volume of emissions produced during the lifecycle of the wind farm, including manufacture, transport, construction, operation and disestablishment.
- 5.2 Estimating a carbon footprint is a complex exercise requiring a detailed breakdown of all energy inputs and associated emissions over the full lifecycle of the plant. For example, where component materials originate and how electricity consumed in their manufacture is generated would need to be known⁴⁸. Some comprehensive studies have been published although with differing results, even after compensating for different assumptions about wind farm project lifetimes and the amount of generation it will produce⁴⁹. By way of illustration, Figure 11 shows carbon footprint estimates derived from a number of detailed studies⁵⁰.

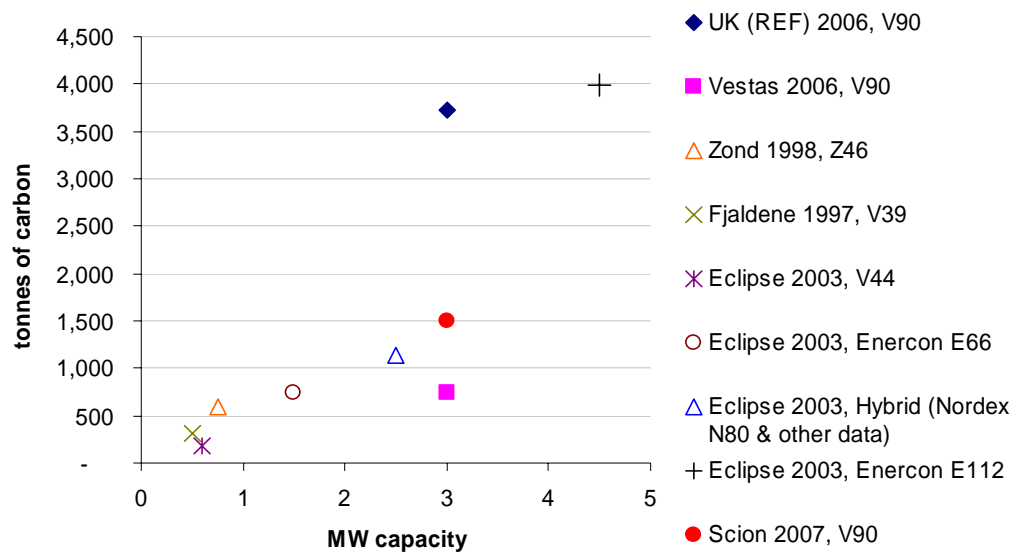
⁴⁸ For example, a study undertaken by Scion (to estimate the carbon footprint of the Trustpower Kaiwera Downs wind farm proposal) relied significantly on a lifecycle assessment report published by Vestas for its 3 MW wind turbine. The Vestas report is entitled "Life cycle analysis of offshore and onshore sited wind power plants based on Vestas V90 3.0 MW turbines", the report and can be found on the Vestas website (www.vestas.com).

⁴⁹ Lifecycle results are often expressed in terms of carbon embodiment per kWh produced over the life of a plant.

⁵⁰ The legends in Figure 11 and Figure 12 refer to the following data sources.

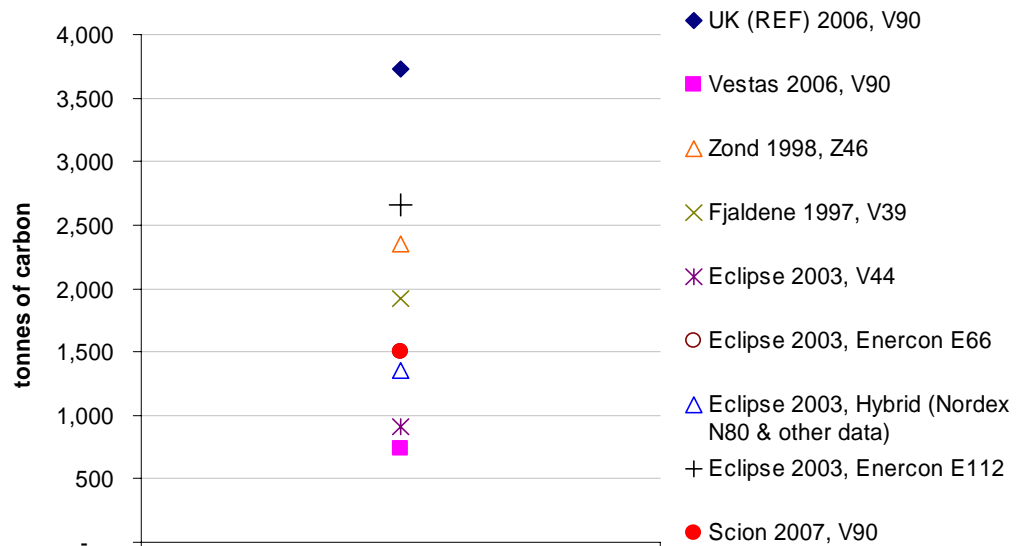
Scion	"Carbon Footprint of Proposed Kaiwera Downs Wind Farm", SCION, 2007
UK (REF)	"A guide to calculating the carbon dioxide debt and payback time for wind farms", 2006, Renewable Energy Foundation
Vestas	"Life cycle assessment of offshore and onshore sited wind power plants based on Vestas V90-3.0 MW turbines", Vestas, 2006
Eclipse	"Wind Turbine Systems (WT): ECLIPSE", Annie Chataignere & Denis Le Boulch, EDF R&D: The European Commission, 2003
Zond	"Net energy payback and CO2 emissions from wind generated electricity in the Midwest", S.W. White & G.L. Kulcinski, University of Wisconsin, 1998
Fjaldene	"Externe National Implementation, Denmark", Lotte Schleisner, Risø National Laboratory & Per Sieverts Nielsen, the Technical University of Denmark, 1997

Figure 11: Carbon footprint estimates



5.3 Figure 12 shows the same data scaled according to a wind turbine generator 3 MW capacity. While results are not really scalable in such a simple manner⁵¹, it is a useful way of illustrating how carbon footprint estimates vary.

Figure 12: Study results scaled to 3 MW WTG capacity



5.4 I note that the estimate of the carbon footprint for a 3 MW wind turbine presented by Mr Cox (3,690 tonnes of CO₂) is at the upper end of the estimates in Figure 12 and approximately 5 times the estimate by Vestas, the Danish wind turbine manufacturer. In his statement, Mr Gallagher estimated that CO₂ emissions

⁵¹ For example, due to any scale economies and technology advances since some studies were undertaken.

associated with the concrete foundations for all turbines would be 5,400 tonnes. This figure, equivalent to 193 tonnes per turbine, is much lower than Mr Cox's estimate of 1,400 tonnes for the mounting and construction of each turbine. I have estimated, from publicly available data as summarised in Table 1, a figure of 865 tonnes.

Table 1: Estimated carbon embodiment per wind turbine foundation

Foundation component	Value
Cement	
Volume of cement (WEL data)	800 m ³
Density of cement ⁵²	2,400 kg/m ³
Total weight of cement [2,400 kg/m ³ * 800 m ³]	1,920 tonnes
Emissions factor for 30 Mpa concrete ⁵³	0.43 tonnes CO ₂ per tonne
CO ₂ emissions [1,920 * 0.43]	825.6 tonnes
Aggregate	
Density of aggregate (WEL data, 350kt per wind-farm)	12,500 tonnes
Emissions factor for aggregate ⁵⁴	2.3 grams CO ₂ per tonne
CO ₂ emissions [(12,500 * 2.3)/1000]	28.8 tonnes
Reinforcing steel	
Quantity ⁵⁵	30 tonnes per turbine
Emissions factor for steel	0.352 tonnes CO ₂ per tonne
CO ₂ emissions [30 * 0.352]	10.6 tonnes
Summary of emissions	Tonnes of CO₂ emitted
Cement	825.6
Aggregate	28.8
Reinforcing steel	10.6
Total emissions	865

5.5 Returning to studies summarised previously, rather than comment on the relative merits of each study I wish to observe that the footprint of a specific 3 MW wind turbine is difficult to estimate accurately. Applying study results to New Zealand projects would also require adjustments to account for project specific requirements,

⁵² "The Physics Fact Book", Katrina Jones, 1999

⁵³ "New Zealand's Greenhouse Gas Inventory 1990-2003", New Zealand Ministry for the Environment

⁵⁴ "Embodied Energy and CO₂ Coefficients of New Zealand Building Materials", Centre for Building Performance Research, Victoria University.

⁵⁵ Estimated based on a single wind turbine in the Renewable Energy Foundation publication "A guide to calculating the carbon dioxide debt and payback time for wind farms", M.J Hall, 2006.

including the project content sourced and/ or constructed in New Zealand. For the purpose of this statement, I shall adopt a conservative upper estimate of 104,000 tonnes for the carbon footprint of the Te Uku project (based on the maximum estimate per 3 MW wind turbine shown in Figure 12).

6. CARBON PAYBACK

- 6.1 'Carbon payback' is an assessment of how long it would take for a new project to avoid emissions equivalent to its carbon footprint. Given the previous discussion, estimating the carbon payback period for a specific wind farm project is difficult to estimate. However, an upper estimate of approximately 104,000 tonnes of carbon dioxide equivalent for the carbon footprint of the Te Uku wind farm indicates a payback period of less than 7.5 months assuming an initial emission avoidance rate of 168,000 tonnes per annum.
- 6.2 Had Mr Cox used the correct thermal emission in calculating his overall emission factor, his estimate of emissions avoided would have been approximately 61,000 tonnes per annum (4.6 times higher). Further, had he applied the correct annual energy production figure for Te Uku (259 GWh), this figure would have been approximately 119,000 tonnes, which is roughly nine times higher than the estimate in his statement. This figure would have given a carbon payback period of approximately 10.5 months, substantially less than asserted in his statement and a similar order of magnitude to my estimate above of 7.5 months.
- 6.3 Other basic errors made by Mr Cox further undermine the credibility of his statement. For example, as noted above, he uses a factor of 0.1 tonnes per MWh for estimating emissions that would be avoided by the Te Uku project. However, instead of using this factor, he then uses an apparently arbitrary much higher figure of 0.4 tonnes per MWh for his alternative generation options, biasing his estimates of emissions reductions for his alternative generation options by 400%.
- 6.4 Some assertions in his statement also suggest Mr Cox does not understand how the New Zealand electricity market works. For example, he asserts that "*new rules coming into force will prohibit the bidding of more than 90% of maximum output from wind turbines without cogeneration*". This may have been lifted, or misinterpreted, from another jurisdiction (perhaps Denmark⁵⁶) but has no relevance to New Zealand electricity market arrangements. He also appears to believe that wind generators

⁵⁶ I say this because Denmark has relatively high levels of wind generation and cogeneration. Unlike New Zealand, it has negligible hydro generation but relies on transmission links with other countries (for example, Norway) for flexible supply.

receive payments for quantities offered (he uses the term *bid*) into the market⁵⁷. In fact, market payments to wind generators are made for actual generation.

Jim Truesdale

January 2008

⁵⁷ For example, he makes statements like “*The fundamental is not what you can produce but what you can sell*” and “*To estimate bid power it has been assumed that WEL will be able to predict wind well enough to achieve a level of 94% of actual following hour minimum*”.