IN THE MATTER of the Resource Management Act 1991

AND

IN THE MATTER of a Board of Inquiry appointed under s146 of the Resource Management Act 1991 to consider an application by Mighty River Power Limited for resource consents to construct, operate, and maintain a wind farm at Turitea

REBUTTAL EVIDENCE OF PAUL CHRISTOPHER BAKER

1.0 Qualifications and Experience

1.1 My full name is Paul Christopher Baker. I have been Managing Consultant for Energy Link since 1 April 2004.

1.2 Energy Link is a provider of forecasting, modelling, consulting and professional training services to the electricity market, and has been doing so since 1996. Energy Link is also on the Panel of preferred consultants for both the Electricity Commission and the Ministry of Economic Development.

1.3 I am responsible for managing Energy Link's consulting activities. This includes:

- Energy Link's electricity and gas price forecasts;
- delivering training courses on the electricity and gas markets; and
- the design of Energy Link's gas market model (*GMarket*) and generation expansion model (*I-Gen*).

1.4 Prior to joining Energy Link I was at the Crown Company Monitoring Advisory Unit (*CCMAU*) within Treasury for over three years. At CCMAU I was responsible for advising Shareholding Ministers on the business plans, strategies, major investment decisions and performance of a number of large State-Owned Enterprises (*SOEs*). These included Genesis Power from 1999 through to 2003, and Meridian Energy and Solid Energy from 2003 to 2004.

1.5 With my grasp of the market drivers in the energy sector, I was responsible for preparing briefing papers for shareholding Ministers on the influence of the SOEs' operations and behaviours during the 2001 and 2003 energy 'crises'. I also prepared papers for the Commerce Select Committee on the financial gearing of the Electricity SOEs, and on the factors in the market that determine the pricing of electricity hedge contracts.

1.6 I was directly responsible for preparing advice for Ministers on projects such as Genesis' acquisitions of retail electricity and gas customers, the construction of the Huntly e3p Power station, its major coal contract with Solid Energy New Zealand Limited, and Meridian's wind farms at Te Apiti and Wattle Point (Australia).

1.7 I have a Master of Commerce Degree with Honours in Operations Research. Prior to joining CCMAU I had extensive experience in the funds management and superannuation industries, utilising qualifications in finance and investment analysis. This included leading strategic and business planning sessions, business to business marketing, and management of wholesale investment products.

2.0 Engagement

2.1 I have been engaged by Mighty River Power Limited to express my opinion on the evidence presented by Molly Melhuish and Bryan Leyland in respect of the Board of Inquiry hearing on the proposed Turitea Wind Farm (*Turitea*).

2.2 I confirm that I have read, and am familiar with, the Code of Conduct for Expert Witnesses in the Environment Court set out in Consolidated Practice Note 2006.

2.3 In preparing this statement I have reviewed the evidence presented by Brent Leyton, Molly Melhuish and Brian Leyland in respect of the Board of Inquiry hearings on Turitea.

3.0 Summary

3.1 The general thrust of both the Melhuish and Leyland papers is that there are better alternative projects available than Turitea. My view is that while this may, or may not be the case, the market is designed to enable the generators to assess the complexities of each proposal. Mighty River Power is best placed to determine whether this project will provide the Company with an adequate return on its investment.

3.2 Leyland has highlighted the potential costs of increased wind generation in the Tararuas. These costs are relevant, but only in the context of matching these costs against all generation types and locations, that is, the different costs associated with other options may be greater than those associated with increasing wind generation in the Tararuas. This is clearly a highly complex process, which is a key reason why there has been a trend for electricity markets around the world to move to a market based approach rather than centralised planning. In the context of an electricity market, the financial risks associated with building, owning and operating a new power station fall on those with the greatest incentive to manage those risks, which over the longer term ensures that the economic efficiency of investments in new plants are maximised for the benefit of society as a whole.

3.3 It is the Electricity Commission's role as market administrator to ensure that the structure of the market is such that the pricing signals for new electricity generation developments are clear and undistorted. Questions in respect of costs of frequency keeping, peaking plant generation, transmission constraints, et cetera. are signalled to generators through market prices and charges. It is Mighty River Power's role to understand the likely impact of electricity prices and such charges on the viability of its generation projects.

3.4 The Electricity Commission's Statement of Opportunities (*SOO*) report is designed to provide guidance on potential, and hypothetical, development paths for the electricity market. It provides a perspective on the resource requirements and, in particular, the likely upgrades required to Transpower's electricity grid to facilitate economically efficient development paths for new generation under a range of scenarios. It is not intended to be prescriptive for the type or location of new generation developments.

3.5 If Turitea is expected to earn greater or lesser revenues than alternative projects, or incur particular fees for connection to the grid, then I would expect that Mighty River Power would take those elements into consideration when making the decision to proceed.

3.6 The capital cost of Turitea if built, therefore, cannot impact on electricity prices. Issues such as location factors, daily and seasonal generation patterns are issues for the generator to consider in its investment decision, but do not represent a cost to the consumer. It is critical to understand that building the wind farm, therefore, cannot result in a higher cost of electricity for the consumer.

3.7 Turitea is located on the central backbone of the transmission grid through the lower North Island. As such, alternative generation developments may easily have a greater impact on grid losses and constraints than Turitea. The potential need for any upgrade to lines on the grid should not be a factor in this decision.

4.0 Capital costs

4.1 Leyland's evidence highlights that there is uncertainty in ascertaining the exact costs of Turitea. I have not explored the detail of his analysis, but point out that those uncertainties are unlikely to be greater than those of other prospective generation development projects. Capital costs are also not stable over time as the availability of finance, demand for turbines, and exchange rates continues to change.

4.2 For this reason, Energy Link always uses a range of potential development scenarios in its long term (15 year) electricity price path projections. Any ranking of the economics of Turitea amongst a range of alternative new generation options can only ever be a probabilistic estimate. Even when the project has a committed costing from suppliers, the expected revenues remain uncertain depending on the performance of the plant, climatic conditions, and spot prices.

4.3 Leyland (at paragraph 3.2) states, "*The most important cost is the capital cost of the wind farm itself"*. In the context of the return to Mighty River Power on its investment, and the overall economic benefit of the project, this is true. However, in the context of the cost of electricity supplied to consumers, the capital cost of Turitea has no relevance.

4.4 Wind farms are required, because of their intermittent nature, to offer their generation output in to the electricity market a $0.01 per MWh. This means that irrespective of the wind farm's capital cost, Turitea will only ever receive the wholesale market price for its output. (Mighty River Power may enter into other contractual arrangements that refer to the wind farm output, but these arrangements would have no impact on the wholesale spot price.)

4.5 Because the wind has no cost, and Turitea will always offer its output at $0.01 per MWh, Turitea must nearly always[1] be replacing higher cost generation, and thereby have the effect of reducing the wholesale spot price.

4.6 Melhuish (at paragraph 77) states, "*Officials describe it as efficient to base retail electricity prices on the long run marginal cost (LRMC)"*. Melhuish then contends (77) '*But retail prices rise as new power stations become more expensive, driving up LRMC. Wind generation will only drive retail prices down if they are cheaper to build than other types of new power generation.*' Melhuish appears to be implying that Turitea is an expensive wind farm with a high LRMC, and will therefore cause retail prices to increase.

4.7 As retail prices represent a significant forward commitment by the retailer, retailers do need to consider future wholesale prices when setting retail prices. It is true therefore that over the long run (assuming the electricity market is sufficiently competitive) retail prices are expected to track LRMC plus the costs of retailing (although there is no guarantee that prices will ever reach or exceed LRMC for any sustained period). However, it would be wrong to suggest that declining any new generation project, expensive or otherwise, could have the effect of reducing either wholesale or retail prices.

[1] The only exception occurs when demand is very low and there is an excess of generation that 'must run' because of resource consent or technical issues.

4.8 As an example, we can take a hypothetical scenario where a diesel peaking plant is built with a LRMC of $500 per MWh and a short run marginal cost (*SRMC*) of $350 per MWh. The plant would only run infrequently as wholesale prices would still average below $350. It would still contribute to reducing average prices overall however as it would increase supply by providing additional generation during periods of extreme hydro shortage. Other lower cost generation options would still be built. It would not be rational to suggest that this plant would result in an increase in retail prices. (Unless of course it was owned by the Electricity Commission and funded through a direct levy on electricity consumers.)

4.9 I consider that it would be unlikely that Mighty River Power would proceed with Turitea if the project does not cover its weighted average cost of capital, but irrespective of that, the project cannot cause wholesale or retail electricity prices to be higher, either in the short or long run.

5.0 Central planning and the Statement of Opportunities

5.1 A part of the Electricity Commission's role is to produce a SOO Report. To quote the Electricity Commission:

"The purpose of the SOO is to enable the identification of potential opportunities for efficient management of the grid, including investment in upgrades and transmission alternatives. The SOO is also relevant to the Grid Investment Test (GIT) and the Grid Reliability Standards (GRS) under part F, each of which reference the possible future scenarios set out in the SOO. There are also links between the SOO and documents prepared by Transpower, as grid owner, pursuant to part F: the Grid Reliability Report (GRR), the Grid Economic Investment Report (GEIR), and Grid Upgrade Plans (GUPs)."

5.2 The Electricity Commission constructs a range of potential scenarios when it prepares its SOO Report. Each scenario in the SOO is designed to reflect the outcome under circumstances that particularly favour that outcome. For example, a high gas scenario where there is an abundance of gas available for new gas turbines, or alternatively, a high carbon cost scenario where renewable generation projects are considerably cheaper than thermal power stations.

5.3 By definition therefore, none of the SOO scenarios actually represent a most likely development path. This is appropriate as the SOO is intended to test the range of potential developments and grid development needs.

5.4 For each of these scenarios a representative range of new generation projects is presented. These are not intended to present any particular mandate to those projects.

5.5 Melhuish (at paragraph 85) makes the point that:

"*The wind generation resource being investigated in Manawatu and Wellington is so large that it is unlikely to be economic to connect it to existing transmission lines. The 2008 SOO however does not indicate any need to increase transmission capacity in the Manawatu as a result of increases in wind generation.*"

5.6 I believe that the reference may be referring to the following extract from the Transpower Annual Planning Report 2009:

"There are several investigations and proposals for wind farms connecting to the 220 kV double circuit line between Bunnythorpe, Linton and Wellington. They could be connected at Linton or at new connection points along the line. Examples are the proposed Turitea wind farm near Linton and Puketiro (in the Wellington region). This is a high capacity line and the effect of some additional generation on transmission capacity between Bunnythorpe and Wellington will be a small net percentage increase or decrease in transfer capacity, depending on the direction of power flow.

However, the wind generation resource under investigation is so large that, due to transmission constraints, it is unlikely to be economic to connect it all to this line."

5.7 The link between Bunnythorpe and Haywards in Wellington is a core component of the grid. As such, alternative investments to the Turitea wind farm northwards of Bunnythorpe or in the South Island are also likely to result in higher power flows through this region from time-to-time. Transpower shows an upgraded link between Bunnythorpe and Haywards in their possible configuration for 2019.[2] If Turitea does not proceed, then that particular section of the grid might still be required to carry increased power flows from alternative projects.

5.8 I agree with Melhuish (at paragraph 86) that the cost of expanding grid assets is a "*true externality to the wind farm proponent*" but contend that this is consistent for all new projects connecting to the grid, with the notable exception of the South Island, where the costs of the HVDC link are directly charged to generators. Replacing Turitea with an alternative project can just as easily require more significant upgrades on other parts of the grid.

5.9 The Electricity Commission's SOO report highlights a range of new generation scenarios and various grid options associated with those scenarios. The relative costs have been summarised on a Net Present Value (*NPV*) basis and the results are presented in Table 22, on page 171 of the report. I have copied this below.

[2] Figure 12-4 Transpower Annual Planning Report 2009

Table 22 NPVs of pre-tax costs in the market development scenarios (committed transmission projects are excluded)

Discount rate (real, pre-tax)	Scenario	Generation NPV (2007 $m)	Transmission NPV (2007 $m)	Total NPV (2007 $m)
Five percent	Sustainable Path	36,129	1,093	37,222
	South Island Surplus	35,743	1,055	36,798
	Medium Renewables	30,763	1,114	31,877
	Demand-side Participation	33,093	1,059	34,152
	High Gas Discovery	32,554	1,044	33,598
Seven percent	Sustainable Path	27,016	779	27,795
	South Island Surplus	26,711	754	27,465
	Medium Renewables	23,314	787	24,101
	Demand-side Participation	24,705	757	25,462
	High Gas Discovery	24,487	747	25,234

5.10 The highest NPV for transmission investment in this table, under the Electricity Commission's central discount rate of 7%, is $1,044 million. The cost of the generation options ranges between $23,314 million and $27,016 million, a spread of $3,702 million. The spread in potential generation costs is close to three times the total cost of the grid upgrades.

5.11 In my view, this relationship means grid upgrades should support generation development plans, rather than the alternative of seeing generation projects selected to avoid grid upgrades.

5.12 Similarly, from a market competition perspective, in his review of the Wolak report for the Commerce Commission, Nils-Henrik Von Der Fehr states that:[3]

"*Maintaining and expanding transmission capacity beyond levels that would be deemed necessary from purely operational reasons may be required to counteract the tendency to geographical concentration*."

5.13 It is therefore my view that any potential need to upgrades lines on the Transpower grid should not be a factor in considering whether Turitea should proceed or not. This view is consistent with the Transmission Pricing Methodology determined by the Electricity Commission, which dictates that the grid, excluding the HVDC link, is paid for by consumers rather than generators.

[3] Nils-Henrik M. Von Der Fehr, Universitetet I Oslo: Peer Review of Professor Wolak Report for the Commerce Commission.

6.0 Generic costs associated with wind generation

6.1 Leyland (3.7 – 6.4) highlights a number of costs associated with the operation of the electricity market that are expected to increase with increased reliance on wind generation. He states (5.14), '*The inescapable conclusion is that a substantial amount of generating capacity will have to be allocated purely to cover the risk associated with the variability and unpredictability of the output of the wind farms during system peak.*'

6.2 My contention is that the electricity market is designed to ensure that such costs are appropriately signalled to generators and consumers through market prices and charges. The market is not necessarily perfect in this respect, and there may be changes to the pricing regime in the future, but I do not believe that there is any basis for attributing additional costs to Turitea.

6.3 Under the Electricity Act 1992, s172N: *The principal objectives of the [Electricity] Commission in relation to electricity are –*

a. to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner; and

b. to promote and facilitate the efficient use of electricity.

Under the specific outcomes stemming from those objectives, the EC is expected to achieve (with my underlining):

d. incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment:

e. the full costs of producing and transporting each additional unit of electricity are signalled:

g. the electricity sector contributes to achieving the Government's climate change objectives by minimising hydro spill, efficiently managing transmission and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables and distributed generation.

6.4 Given its requirements under the Electricity Act 1992 I take it that the Electricity Commission has the incentive and authority to ensure that over the long run the true costs of each form of generation are appropriately signalled in market prices. Specifically, the Electricity Commission has undertaken a Wind Generation Investigation Project (*WGIP*), the purpose of which is:[4]

"*To accommodate the connection of further wind generation while maintaining the integrity of the New Zealand power system, the Commission initiated a strategic project to assess the likely impact of wind generation development over the next 5 to 10 years. This study will identify wider power system and electricity market implications of additional wind generation and how these can be best resolved to enable the development of wind generation on a "level playing field" with other generation sources.*"

[4] http://www.electricitycommission.govt.nz/opdev/comqual/windgen/wgip

6.5 As part of this project the Electricity Commission has already carried out extensive modelling to analyse the potential impact of a high level of penetration of wind farms in New Zealand. If the Electricity Commission felt that there was a need to limit the penetration of wind generation then it could potentially utilise a number of mechanisms to implement that. The most likely would be some form of levy on generation, grid access, or capacity payments. I am not aware of any such levies or payments being considered at this point.

6.6 There are still a number of points in Leyland's evidence that are worth addressing:

6.7 **Frequency keeping:** Leyland states that increased frequency keeping costs should be attributed to wind generators (at paragraph 3.8). Frequency keeping ensures that the amount of electricity generated is tracking closely to demand. It is designed to cater for the error factor in the System Operator's five minute demand forecasts; that is, in the time that it takes the System Operator to re-dispatch generators to match anticipated demand.

6.8 While the cost of frequency keeping has increased over recent years, this cannot be attributed to wind generation. The generators providing frequency keeping are assumed to price the service on the basis of the opportunity cost of providing energy or reserves. They can also receive payments for being 'constrained on' when there is limited competition for providing frequency keeping for any reason. The cause of volatility within the +/- 50 MW band required by the frequency keeper is irrelevant to the cost of providing the service. Wind generation will only contribute to an increase in the cost of frequency keeping if the Electricity Commission determines that increasing system volatility due to wind dictates that the generation band for frequency keeping should be increased from +/- 50 MW to some higher figure.

6.9 **System operation costs:** The System Operator can only dispatch generation that is offered in to the market. It does signal to the market in advance on likely generation requirements, and this becomes more uncertain with an increasing proportion of wind generation. It is not correct, however, to state that "*the system operator will be forced to keep thermal and hydro plant connected to the system and running at less than full load*" (Leyland at paragraph 3.9).

6.10 In any case, it is relatively rare for the thermal power stations in New Zealand to operate continuously at full load.

6.11 Typically, each of the four units at the Huntly power station can operate between approximately 80 MW and 250 MW output, giving a range of almost 680 MW between minimum and maximum output.[5] Furthermore, Huntly is expected to become more of a back-up generator over time as the cost of carbon emissions is accounted for. Huntly can maintain a stockpile of coal that gives it operating flexibility over many months.

6.12 Advances in forecasting wind some hours in advance may also help reduce some of the problem of allowing for uncertain wind generation. New Zealand also has the advantage that its hydro generation assets provide a great deal of short term flexibility. Leyland quotes the limitations of the Waikato system in providing peaking capacity (at paragraph 5.6), but ignores Tokaanu in the Central North Island that can provide 240 MW of peaking capacity alone. This flexibility of the hydro systems is available in even quite low hydro storage conditions. The cost of maintaining hydro generation availability in reserve is minor in the context of the overall market.

[5] Frequency keeping duties might reduce this to 550 MW.

6.13 **Meeting demand when the wind is not blowing:** Wind farm output is seasonal, and there will be periods when a greater level of alternative generation is required. The pattern of electricity prices through these periods will reflect this and provide an incentive for both hydro generators to retain storage, and for thermal generators to maintain sufficient flexibility in their capacity and fuel arrangements to maximise generation during those periods. An example of such capacity is the new 200 MW gas fired power station being built by Contact Energy at Stratford, and associated gas storage facility that it is commissioning nearby at the Ahuroa gas field.

6.14 **Capacity during system peak demand periods:** I agree with Leyland that wind farms cannot be relied upon to meet demand during periods of peak demand. There is therefore a need for the market to have sufficient capacity to meet demand in the absence of wind generation. The New Zealand electricity market is in fact rather unusual in that, to date, it is not generally constrained[6] by generation capacity, but instead experiences significant periods of fuel constraints, i.e. periods when the hydro storage levels have been relatively low. Leyland refers to this at paragraph 4.3.

6.15 As our reliance on wind and geothermal generation increases, the potential to experience capacity constraints must also increase, which means that electricity prices may spike upwards more often during peak demand periods. These price spikes provide an incentive for hydro generators to maximise their ability to capitalise on such opportunities through their plant design, reservoir management, and offering strategies. Similarly, any new thermal power stations are more likely to be open cycle gas turbines with peaking capability rather than combined cycle gas turbines that need to run with a minimum base load. Generators will also seek more flexible gas supply arrangements from producers.[7] I do not agree with Leyland (at paragraph 6.2) that open cycle gas turbines are 'relatively expensive' given that Genesis Energy, Mighty River Power, and now Contact Energy have all invested in such plants since 2004.

6.16 If the market fails to respond to market signals and build sufficient peaking capacity alongside the renewable power stations, then the Electricity Commission has the option of introducing some form of capacity payments. Such payments would effectively divert some of the existing revenues from consumers to the parties that could guarantee their generation capacity. I suspect that such a system would not necessarily result in a higher cost to consumers, but may merely be a redistribution of existing revenues away from wind farms.

6.17 New Zealand is therefore well placed to cope with a greater proportion of its electricity generation coming from wind.

6.18 Based on these points, it is my view that it would be inappropriate to take into account when considering the costs and benefits of Turitea any provision for:

- frequency keeping;
- system operation costs;
- capacity during system peak demand periods; or
- back-up generation.

To do so would be inconsistent with the market signals that the Electricity Commission is responsible for supporting.

---

[6] There are of course times when thermal plant outages, lines constraints and reserves requirements do create regional capacity constraints, the most significant of which is currently the capacity of the HVDC link and its associated reserve requirements.

[7] Flexible gas supply arrangements are largely a reflection of the level of investment made in the gas field and associated pricing levels, rather than any inherent physical constraints.

7.0 Quantifying the available resource

7.1 Melhuish appears to be suggesting (at paragraphs 51–54) that as New Zealand has a very large wind resource; Turitea can be declined without adversely impacting on New Zealand's likelihood of achieving a very high penetration of renewable generation. I have not had the opportunity to review in detail the studies on the resource, but it seems in all likelihood that wind farm developers will naturally target those projects that offer the greatest financial return over time.

7.2 Energy Link has long held the view that while there are a great many wind projects seeking resources consents, it will be over ten years before even 25 % of these projects are completed. That does not mean that the current level of activity in seeking resource consents is inappropriate. In volatile times it is extremely important that the electricity market has the flexibility to respond to changing economic conditions. It is apparent, for instance, that Genesis' Awhitu Peninsula project might well have proceeded had the delays in the consenting process not meant that the costs of the project escalated and made it non-viable in the short term.

7.3 I very much doubt the suggestion in Melhuish's report (at paragraph 62) that there is a risk of "*a surplus of generation capacity*".

7.4 Rejecting the Turitea Wind Farm on the basis that there are many additional projects available would seem to be delaying developments in favour of potentially more expensive projects. I do not believe that Melhuish's analysis is sufficiently robust to support such a rejection.

8.0 Locational effects

8.1 Melhuish (at paragraph 84) states that "*siting wind farms near Auckland would lead to less commitment of transmission capacity and reduced losses compared to siting them in the Manawatu*". I do not have any argument with that thought, but I do not believe that in the absence of Turitea, we will necessarily see over 300 MW of renewable generation being built nearer to Auckland. The alternative is just as likely to see the advancement of the projects already consented in the South Island.

9.0 As Leyton points out (at paragraph 8.5) wholesale electricity prices in New Zealand reflect the transmission losses and constraints at every node. New generation developments will take those into account as well as the other costs and benefits associated with each particular location. The benefit of being close to Auckland has not yet resulted in Genesis Energy proceeding with its Awhitu Peninsula project.

Paul Baker
5 June 2009