Project activity no. 1259 "Enercon Wind Farm (Hindustan) Ltd in Karnataka".

1. Further demonstration of the additionality of the project activity is required.

The additionality of the project has been demonstrated using the Tool for demonstration of additionality version 3.0 approved in the 29th meeting of the Executive Board. In accordance with the guidelines of the additionality tool, we have chosen to use the Investment analysis tool i.e. step 2, to assess the project's additionality. As per step 2 of the additionality tool, the proposed project activity is additional if the project activity is economically or financially less attractive than at least one other alternative, identified in step 1, without the revenue from the sale of certified emission reductions (CERs).

Further, as per the additionality tool, the investment analysis to demonstrate economic attractiveness of the project can be conducted either in the form of a (i) simple cost analysis, (ii) investment comparison analysis or (iii) benchmark analysis.

The project activity generates and supplies electricity to the Karnataka state electricity grid and earns revenues from sale of electricity to the grid. Therefore, option (i) simple cost analysis can not be applied. The project proponent has chosen to carry out option (iii) Benchmark Analysis and the financial indicator that is identified is the equity return or equity Internal Rate of Return (IRR).

Post tax equity return or equity IRR is used as the appropriate financial indicator because in the Indian power sector, the post tax equity return is an established benchmark for projects in public or private sector based on cost-plus regulations prescribed by the Central Electricity Regulatory Commission that is mandated by the statute of the Electricity Act 2003 to set the terms and conditions for determination of tariff for electricity generation, transmission and distribution activities. The CERC in its order dated 24th January 2004 had stated that a post tax equity return of 16% can be considered as appropriate for Independent Power Producers (IPPs). Incentives, foreign exchange variations and efficiency in operations are in addition to this benchmark of 16%. The CERC order is attached as Appendix 1 to our response. The response to question 3 further elaborates the appropriateness of this benchmark.

The Karnataka Electricity Regulatory Commission (KERC) has considered a 16% post tax equity IRR as the appropriate equity return while determining the tariff for non conventional energy based power plants (Refer Appendix 2 to the document). Accordingly, a post tax equity IRR of 16% is considered as the appropriate benchmark return for the project, if the project has a equity IRR of less than 16%, then it can be considered as additional.

The financial analysis of the project, which was submitted as part of the registration documents, clearly shows that without considering CDM revenues, the project has a post-tax equity IRR of 11.7%, which is less than the benchmark return of 16%. Therefore, in accordance with the guidelines provided in the additionality tool, the project activity may be termed as additional.

As we had already carried out a full investment analysis in the PDD, we understand that this question relates to providing evidence of barriers. We had refrained from using barrier analysis in the PDD as we believed that the investment analysis was sufficient and rigorous to demonstrate additionality. The Investment analysis clearly shows that the investment returns generated by the project are no sufficient to justify the investment involved, unless CDM incentives are considered. However, there are several barriers impeding the development of the project activity and these are explained below.

Barriers due to price sensitive electricity market:

The electricity market in India is price sensitive, so much so that politicians often make offers of free electricity in order to win elections. There are many instances where attempts to raise the electricity

tariffs have been met with vehement protests and general unrest in the public. State governments, driven by political considerations, impose minimal tariff on domestic and agricultural consumers that are disproportionate to the cost of electricity consumed by these consumers. Consequently, bulk of the cost of generating and supplying electricity has to be recovered from the Industrial consumers. Needless to say the industry, in an attempt to reduce the incidence of higher electricity costs, favors generating sources with the lowest costs.

The political approach of the government means that the distribution utilities have very little maneuverability relating to tariff setting and the focus therefore is to procure energy at the least cost. This is evident from the KERC order (Refer - Appendix 2) which states:

KPTCL/Escoms have opined that merit order should be applicable to renewable sources of energy also as otherwise they will be constrained to purchase this high cost power when adequate power is available at much lower tariff especially during monsoon season. Such purchase would not be in the interest of the licensees and consumers. With the introduction of ABT, KPTCL also explained that if merit order is not applied, KPTCL may be purchasing power at higher tariff from renewable sources of energy when it is not required and will be forced to sell the same outside the state at lower tariff incurring huge losses.

As can be seen clearly, the transmission and distribution utilities in the state have no consideration whatsoever to promote renewable sources and obviously prefer fossil fuel based plants owing to the low cost of generation. The industrial consumers also lobby strongly to promote fossil fuel based projects.

Barriers due to high cost of wind projects

India has a total wind generation potential of 45,000 MW (Refer – Appendix 3), the study to assess wind resource potential in India was first conducted way back in 1985 and the policy for promotion of wind projects was introduced in 1993. However, even after nearly 15 years since the policy to promote wind projects was introduced, India has managed to achieve wind capacity installations of 7,231 MW[1] i.e. less than 15% of its potential (Refer – Appendix 3). This is despite of the fact that maximum capacity has been added in the last two years, aided by CDM (The common practice test in response 4 further elaborates this). The situation in Karnataka is also similar, Karnataka has a wind potential of 7023 MW against which installations have been 853 MW till date (Refer – Appendix 4). The reasons for this slow uptake in mainstreaming of wind projects are explained below:

Electricity generation by wind projects is infirm since it is driven by the wind velocity and density, variables that are beyond the project developer's control. Therefore, among all energy sources that are available, wind energy can never be considered as base-load, neither can wind projects be relied on to provide peaking power. Wind regime in India is characterized by low wind speeds and dusty environment, which results in low Plant load factor for the wind projects. At the same time the capital cost of wind projects is also higher than that of other power projects. The table below provides a comparison of the capital cost and PLFs of various power generation projects.

Category	Cost/MW (Million Rupees)	Normative PLF / CUF (in %)
Wind energy projects	42.5	26.5
Biomass projects	40.0	75.0
Mini-Hydel projects	39.0	30.0
Cogeneration projects	30.0	75.0
Gas Based Projects	25.0	80.0

[1] Source – Ministry of New and Renewable Energy (MNRE), http://mnes.nic.in/ach1.htm

Coal Based Projects	40.0	80.0

(Source KERC order dated 18 January 2005[2], In the matter of Determination of Tariff in respect of Renewable Sources of Energy – Appendix 2)

As can be seen, among all, wind projects have the highest investment cost and the lowest Plant Load Factor. The PLF for wind projects is almost 1/3rd when compared to other projects, which means that the investment cost associated with every unit of electricity generated from a wind farm is three times as expensive as that of other conventional and non-conventional sources. Consider this; the Bangalore Electricity Supply Company (BESCOM) spends Rs. 1.41[3] for every unit of electricity that it buys from NTPC's Ramagundam coal based thermal power plant (Refer Appendix -5). In comparison, BESCOM has to pay Rs.3.40 for every unit of electricity it buys from wind projects in Karnataka (Refer Appendix 2). Clearly, every unit of electricity that is supplied by a wind project, further increases the average cost of electricity generation. Since a large portion of this cost is borne by a single consumer category (industry), there is a very strong industrial lobby that is working to discourage costly generation sources (such as wind) and promote coal based thermal projects that have significantly lower cost of generation as compared to wind.

Critics of wind power projects argue that wind projects are protected by the renewable purchase obligations of the distribution utilities which requires the Discoms to procure certain portion of their power requirements from renewable sources, where as conventional fossil fuel plants are dispatched base on the merit order. Even if this argument were to be true, from an investment perspective conventional fossil fuel plants present a much more lucrative investment alternative than wind. Consider this; it is a well known fact that, India currently has a power deficit situation i.e. the demand for electricity is more than what the existing plants can supply. For instance the state of Karnataka had a peak shortage of 9.8% in FY 2005 (Appendix 6). In the 11th five year plan, the Government of India has targeted a GDP growth rate of 10% and an average growth rate of 8% for the next 15 years. This growth would further widen the demand and supply gap, a situation where merit order will have little influence on dispatch because demand for electricity is significantly more than that can be supplied and hence all plants that can generated will be dispatched to the full. Further, this surge in demand would require capacity addition to the tune of 82,500 MW in the power generation sector over the next 5 years (refer - Appendix 7). Needless to say, to meet such huge power demand, the focus will always be on conventional thermal power plants owing to their low generation cost and high PLF, more so when India has one of the largest coal deposits in the world, sufficient to meet its coal demand for the next 100 years (Refer Appendix 8).

Wind sites where the wind regime is suitable to generate wind-power are typically located on remote hilly areas that are away from load centers. Whereas fossil fuel plants like coal, gas etc. can be conveniently located closer to load centers. In addition, there is also the notion that large scale penetration from wind can destabilize the grid. Further, in case of wind energy projects, there is very little protection to the investor as there is considerable uncertainty over the amount of returns that can be generated by a wind project. Investment returns in wind projects are dependent on the electricity generation from the project which are driven by the velocity and density of wind in the region. Both these factors are exogenous and completely beyond the control of the project developer. High cost of wind energy systems coupled with their infirm generation characteristics and low PLF when compared to other conventional as well as non conventional energy projects act as significant barriers to investment in wind energy projects.

Barriers due to unfavorable regulatory regime

[2] Reference: http://www.kerc.org/order2005/Order%20on%20NCE%20Tariff%20(FINAL).doc

[3] Annex to KERC Order on tariff determination for Bangalore Electricity Supply Company dated 16th October 2006

1. The policy framework for promotion of non conventional energy sources (NCEs) was formulated by the Government of India (GoI) first in 1993-94 and later on by various state governments. After the advent of the Electricity Act 2003, the Electricity Regulatory Commissions took over the role of tariff setting for conventional fossil fuel fired power generation, hydro power generation or non-conventional/ renewable power generation.

   The GoI policy, formulated in 1993 provided for incentives and facilities which included *inter alia* setting predetermined tariff rates for power from NCE sources, effective from 01-04-1994, and tariff escalations year on year. In order to formulate necessary framework to support the plan, Ministry of Non-conventional Energy Sources (MNES) was constituted to act as the nodal agency of Government of India for all matters relating to non conventional/ renewable energy. MNES came out with its tariff guidelines for NCE projects on 13.09.1993. The MNES policy stated that the power purchase price for wind projects would be Rs. 2.25 per kWh for the base year 1994-95 with 5% year on year escalation on the base year price[4]. (Appendix – 9)

   In 2003, the Karnataka Electricity Regulatory Commission (KERC) came out with its order on determination of tariff for NCE projects which set a tariff of Rs. 3.10/kWh for projects implemented after September 2003 and 2% year on year escalation in tariff (Refer Appendix 10). In 2005, KERC came out with a new order relating to tariff determination of NCE projects, which set a tariff of Rs. 3.40/kWh for wind projects and removed the escalation clause that was their in the earlier MNES and KERC policies (Refer Appendix 2). We analyze the tariff that would be applicable to the project under the different regulatory policy regimes that have come up for wind power projects in Karnataka over the years.

Electricity tariff (Rs/kWh)	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	Average
MNES Policy[5]	3.60	3.72	3.83	3.94	4.05	4.17	4.28	4.39	4.50	4.62	4.11
KERC Order 2003[6]	3.29	3.35	3.41	3.47	3.53	3.60	3.66	3.72	3.78	3.84	3.57
KERC Order 2005[7]	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40

   As can be seen, the average tariff for the project over the 10 year period, under the MNES policy, would have been Rs. 4.11/kWh. The average tariff as per KERC's 2003 order would be Rs. 3.57/kWh which significantly lower than the tariff MNES had proposed. The KERC order in 2005 further reduced the applicable tariff to Rs.3.40/kWh. Clearly the various policies have progressively decreased the electricity tariffs payable by the off-taker (KPTCL/Discoms).

2. We also look at the way the applicable tariff of Rs.3.40/kWh has been determined by KERC. The year wise tariff for wind projects in Karnataka estimated by KERC as per its order dated 18th January 2005 (Refer - Appendix 2) is as follows:

Year	Tariff (Rs./kWh)
1st	3.95
2nd	3.82
3rd	3.69
4th	3.56
5th	3.43
6th	3.30
7th	3.18

[4] http://mnes.nic.in/wp4.htm
[5] Rs.2.25 for 1994-95 and 5% annual escalation thereafter
[6] Rs.3.10 for 2003-04 and 2% annual escalation thereafter
[7] Rs. 3.40 for 2005-06, fixed for next 10 years

8th	3.05
9th	2.93
10th	2.80
Average tariff for above 10 years	3.37
Rounded off to	**3.40**

In such cases where the cost of generation varies from year to year, in order to spread out the cost involved in generation of electricity, equitably over the life of the project, the tariff is levelised. However the KERC, while calculating the applicable tariff, took a simple average of the annual tariff numbers, instead of calculating the levelised tariff. Needless to say, a simple average of the 10 year tariff numbers would be less than the levelised tariff of 10 years. For instance, in case of wind in Karnataka, if the annual tariff numbers determined by KERC are levelised over a period of 10 years assuming a discounting factor of 12%, the levelised tariff would be Rs.3.50/kWh (Refer-Annexure 11 which shows the levelised tariff calculations). Therefore only a tariff of Rs.3.50/kWh can ensure investment recovery for wind projects in Karnataka. KERC, by taking a simple average of annual tariff numbers, has determined the applicable tariff at Rs.3.40/kWh, which is clearly not sufficient to ensure recovery of investment costs in wind projects.

3. The tariff for wind energy projects has been fixed for a period of 10 years and at the moment there are no indications from the Regulatory Commission on the type of returns that would be allowed to the investor after the expiry of this 10 year period. Due to the Back loading of tariff, the investment recovery in case of wind projects is not possible within first 6-7 years of the operational life of the project and usually the payback period for a wind energy project races beyond 10 years. The PPA entered with the Discom is valid for a period of 10 years, whereas the operating life of the project is more than 20 years. This means that for a large part of the project's life, there is a great deal of uncertainty over the project's ability to sell the generated electricity. Even though open access regulations permit a generator of electricity to use the state's transmission network and supply directly to the consumer, finding a buyer for the project's electricity will be difficult, considering its infirm nature and high cost, more so when cheaper and more reliable options like coal are abundantly available. Thus full investment recovery itself is at stake in case of wind projects in Karnataka.

4. In India, fossil fuel and hydro plants are allowed a two part tariff recovery where in the plant's are able to recover their full investment cost (plus post tax equity return) each year if they are able to reach a specified level of plant availability. Whereas, in case of wind projects, the tariff is a single part tariff linked to electricity generation instead of machine availability. Since, generation itself is beyond the control of the project developer, there is a great deal of uncertainty over the amount of investment returns that a wind farm will generate each year. This implies that project activity carries a greater investment risk than the fossil fuel and hydro projects where the investment recovery is decoupled from the level of actual generation achieved by the project due to variations in off-take.

   Thus, in case of the project activity, issues such as transmission unavailability, back-down of generation or part-load operations, which are beyond the control of the investors will affect the project activity severely.

Other barriers

1. For conventional sources of power like thermal or Hydro, the usual practice is that the transmission network for evacuation of electricity from the project is set up by the Distribution/Transmission utility. Whereas in case of wind projects, the investor is required to build the interconnecting

transmission line, for transmitting the generated electricity up to the grid substation. The project activity is located in the remote areas of Tumkur and Chitradurga districts; the nearest grid substation is at Hiriyur village which is 30 kms away from the project site. The project proponent had to develop the 30 km transmission line for evacuation of electricity from the project. Further, after commissioning of the project, the transmission line is required to be handed over to the transmission utility at free of cost.

This acts as a significant barrier for investors who find it difficult to develop and bear the cost of transmission lines over such long distances.

2. Wind in India is dominated by the strong south-west summer monsoon, which starts in May–June, when cool, humid air moves towards the land and the weaker north-east winter monsoon, which starts in October, when cool, dry air moves towards the ocean. The period March to August is favorable for wind generation in India. Wind speeds during the period November to March are relatively weak. For this reason, the maximum generation from a wind farm in India is achieved during the monsoon season. However, during monsoon there is maximum generation from hydro projects also because of ample availability of water. During monsoon, the energy demand is also less owing to cooler and favorable climate.

   The cost electricity from a hydro unit is almost 1/3rd of the cost of electricity from a wind farm. The reduced demand coupled with low cost hydro generating stations makes wind projects vulnerable to backing down. Even though Merit Order Dispatch is not applicable to wind power projects, the risk of backing down of the wind generation is always a possibility during the operational lifetime of the project. For example, there are instances when the wind projects in the neighboring state Tamil Nadu were asked to back down during peak wind season because of peak generation from thermal stations (refer - Appendix 12). Given that investment recovery for wind projects is directly linked to generation, any backing down of turbines on account of grid unavailability can have substantial bearing on the project's feasibility.

2 The additionality of the project should be demonstrated using version 3 if the additionality tool.

The PDD for the project has been prepared using the Approved Consolidated baseline methodology for grid connected electricity generation from renewable sources – ACM0002 version 6.0. As per the guidelines given in ACM0002 *the additionality of the project activity shall be demonstrated and assessed using the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the CDM Executive Board, which is available on the UNFCCC CDM web site*[8].

The PDD for the Project Activity was web hosted for public comments from 21st November 2006 to 20th December 2006[9]. During this period the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the CDM Executive Board that was available on the UNFCCC CDM web site was version 2.0. Therefore, in accordance with the guidance given in ACM0002, we used the additionality tool version 2.0 to assess and demonstrate the additionality of the project.

Annex 2 to the EB30 report states that:

The revision of an approved methodology or tool referred to in a methodology shall not affect (i) registered CDM project activities during their crediting period; and (ii) project activities that have been published for public comments for validation using the previously approved methodology or tool,

[8] Refer: Page 2, ACM0002 version 6.0 available on the UNFCCC website
[9] Refer: Para 4.1, page 13 of the validation report

so long as the project activity is submitted for registration within 8 months of the date when the revision became effective.

Version 3.0 of the additionality tool was made public on 16th February 2007[10]. Thus the Project Activity was published for public comments for validation prior to the Version 3.0 of the additionality tool.

The validation exercise for the project was completed - and the request for registration was filed on - i.e. within less than 8 months of the date when the version 3.0 of the tool was made public.

In light of the above, we understand that additionality tool version 2.0 is applicable to the Project Activity. We are however submitting the revised PDD using version 3 of the additionality tool along with this response.

3. Further evidence regarding the investment analysis and common practice should be provided.

Investment Analysis

The excel spread sheet showing the investment analysis along with all the assumptions has been submitted as part of the registration documents. Evidence and justifications of all the assumptions used in the investment analysis were provided to the DOE during validation. A list of the critical assumptions and the evidence that was provided to corroborate these assumptions is provided in the table below:

Assumption	Documentary Evidence
Project Capacity	Purchase Orders
Project Cost	Purchase Orders
Project Commissioning date	Commissioning certificate
Plant Load Factor	KERC Order dated 18th January 2005
Insurance charges	Insurance Premium payment
O&M Costs	O&M agreement
Tariff	KERC Order dated 18th January 2005
Loan amount	Copy of loan sanction letter from Bank
Terms of Loan	Copy of Loan agreement signed with the Bank
Baseline Emission Factor	CO2 database published by Central Electricity Authority

We request the DOE to confirm this.

[10] Refer: EB 29 meeting report

Common practice test

We analyze the extent to which wind energy has diffused in India and how much of it is due to the benefits offered by the Clean Development Mechanism. As explained earlier, installed capacity of wind in India is barely 15% of the country's wind potential and the situation in Karnataka is no better, against an assessed potential of more than 7000 MW, the state has only managed to install 853 MW as of 31 March 2007 (installed capacity was even less when the project activity started). The table below provides details of wind capacity additions in Karnataka since the promotional policy for wind was first introduced in 1994-95.

SL.NO	Financial year	Capacity allocated in MW	Capacity commissioned in MW
1	1994-95	0.55	0.55
2	1995-96	4.00	1.35
3	1996-97	14.56	3.95
4	1997-98	32.50	12.04
5	1998-99	45.60	1.25
6	1999-00	394.16	18.09
7	2000-01	125.60	3.75
8	2001-02	358.30	28.80
9	2002-03	806.05	55.46
10	2003-04	409.10	83.17
11	2004-05	555.40	204.55
12	2005-06	1,575.10	174.63
13	2006-07	2,397.20	265.95
14	2007-08	305.00	-
	Total	**7,023.12**	**853.54**

(Source: http://www.kredl.kar.nic.in/docs/Yearwise_allotment_and_commissioned_wind_power_projects.xls - Appendix 4)

As can be seen, wind in Karnataka has picked up in the last three years. More than 3/4th of the state's installed capacity has been added in these years. It is interesting to note that the promotional policies for wind in the state have not witnessed any significant change in the last three years. An analysis of the current CDM pipeline will clarify the role CDM has played in promoting wind projects in the state. India ratified the Kyoto protocol in 2002, since 2003-04, close to 720 MW of wind projects have come up in Karnataka. In the current CDM pipeline, 190 MW of registered wind projects are from Karnataka, close to 269 MW of wind projects are under the validation and registration process and another 150 MW of wind is currently in project development stage which will enter the CDM pipeline soon. Out of the 720 MW that has come up, 609 MW of capacity or close to 85% are already in the CDM pipeline and more are expected to follow. If projects under CDM are excluded, the installed capacity of wind in Karnataka (excluding CDM pipeline) would be 276 MW or less than 4% of its potential.

We also analyze the extent to which wind energy projects have diffused in the electricity sector in Karnataka. In 2004–05, wind electricity generation in Karnataka was 489.53 GWh[11] (Refer Appendix – 13) and the total electricity availability at bus-bar in the state of Karnataka was 33,523.92 GWh[12] (Refer

[11] Table 3.4 titled "Gross Electrical Energy Generation (Utilities Only) Primemoverwise, Regionwise / Statewise During 2004-05" in chapter 3 of the CEA general review 2006

[12] Table 5.3 titled "Statewise System Losses During 2004-05" in chapter 5 of the CEA General review 2006

Appendix – 14). This works out to 1.45%, showing that wind energy power generation is insignificant as compared to other power project generation sources in Karnataka.

Clearly, wind power project development in Karnataka is insignificant when compared to the power sector of Karnataka. Further, wind power project development is substantially dependent on CDM mechanism and thus is not common practice.

4. Further validation of the appropriateness of the benchmark is required.

We would request the DOE to comment on this as this relates to validation. However, we would like to clarify the following from a project participant's perspective:

The relevant benchmark (post tax equity returns) has been derived from the benchmark that has been long used in the power generation sector, first set by Government of India policy notification (1991) and later, when the Central Electricity Regulatory Commission and State Electricity Regulatory Commissions (and in some instances, the state government policy notification) took over the role of tariff setting (mandated by the Electricity Act 2003), by their respective tariff orders/regulations/notifications. Post tax equity return has long been an established benchmark to attract private sector finance in to the Indian power sector (electricity generation), whether it is for conventional fossil fuel fired power generation, hydro power generation or non-conventional/renewable power generation. We provide below an overview of the regulatory regime that govern the tariff determination for electricity sector investments in India.

In India, activities in the electricity sector such as generation, distribution, transmission and trading of power come under the purview of a comprehensive legislation called the Electricity Act 2003. As per the Electricity Act, the power to determine the tariff to reach an acceptable IRR relating to generation, transmission and distribution of electricity is vested with the Electricity Regulatory Commissions. Some of the provisions laid down by the Electricity Act for tariff determination are reproduced below:

The Appropriate Commission[13] shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:-

- *the principles and methodologies specified by the Central Commission[14] for determination of the tariff applicable to generating companies and transmission licensees;*
- *the generation, transmission, distribution and supply of electricity are conducted on commercial principles;*
- *the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;*
- *safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;*
- *the principles rewarding efficiency in performance;*

The Central Electricity Regulatory Commission, Terms and Conditions of Tariff, Regulations 2004 dated 26 March 2004 set out the principles of tariff setting for generation projects. The principles allow full cost recovery plus the required return on equity (denominated in post tax equity return) for the power generators. The CERC in its order dated 24th January 2004 had stated that a post tax equity return of 16%[15] can be considered as appropriate for Independent Power Producers (IPPs). Incentives, foreign exchange variations and efficiency in operations are in addition to this benchmark of 16%. The CERC order is attached as Appendix 1 to our response.

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[13] State Electricity Regulatory Commission
[14] Central Electricity Regulatory Commission
[15] Refer: Para 1, Page 122 of CERC order dated 24th January 2004

There are some variances in the approach followed by a particular regulatory commission as to what should be the level of the appropriate post tax equity return should be, as the regulatory commission attempts to balance the interests of the consumers (lower tariff) and the interests of the generators. But there is uniformity in selecting the benchmark as post tax equity return by all the state electricity regulatory commissions and the Central Electricity Regulatory Commission.

Further, while setting the generation tariffs for wind power projects, a state electricity regulatory commission goes through a transparent and detailed process for determining each of the parameters that impact the tariff and obtains relevant data in relation to each parameter from the various stakeholders. The regulatory commission goes through this extensive public process and using the various cost parameters, the key operating parameters and the required rate of return (post tax equity return), it establishes the tariff for wind energy generation by aggregating the costs (including required rate of returns) and dividing by the expected generation from the wind projects.

As mentioned above, the regulatory commission also carries out its mandate as striking a balance between the consumers' interests and generator's interests. Clearly, the regulatory commission cannot allow any generator to make excess profits at the expense of the consumers and as the tariff is set *ex ante* based on various parameters, the parameters themselves are chosen on a conservative basis (lower benchmark rate of return for equity, higher benchmark for plant load factor/expected generation, etc.) so as to lead to a conservative per unit generation tariff.

The Option III - Benchmark analysis tool allows for equity returns as the appropriate benchmark. To quote from the text of both version 2 and version 3 of the tool

"*Identify the relevant benchmark value, such as the required rate of return (RRR) on equity. The benchmark is to represent standard returns in the market, considering the specific risk of the project type, but not linked to the subjective profitability expectation or risk profile of a particular project developer.*"

This fits in well with the choice of equity rate of return that was chosen for this project, based on what the various electricity regulatory commissions' orders. We believe that since the regulatory commission/government notifications provide a very sound, rigorous and transparent basis for the benchmark returns and this has been in use in India for a very long time, this may be accepted as the appropriate benchmark for the project activity.

5. Justification and the validation of the PLF is required in the context of this specific project activity.

As explained earlier, the state regulatory commissions are mandated by the Electricity Act to determine tariff in a manner that assumes commercial principles, encourages competition, efficiency and economical usage of resources, ensures reasonable recovery of cost of generation, rewards efficiency in performance[16] and safeguarding the interests of the consumers. The Electricity Act also requires that tariff should be determined in a transparent manner that requires the regulatory commission to consider the views and opinions of the public in determining the appropriate tariff. The list of participants in the tariff determination process is enclosed with the response.

The project activity involves generation and sale of the electricity to the state utility, therefore in accordance with the Electricity Act, the tariff for the project is determined by the Karnataka Electricity Regulatory Commission ("KERC"). KERC Order for determination of tariff from wind generation sources has been based on extensive consultation, obtaining information from various stakeholders (including wind farm developers, government agencies, utilities and other stakeholders). KERC after reviewing the appeals of various petitioners and examining the data available on wind profile in the state, in its order dated 18/January/2005 (Appendix 2), ruled as follows "***The Commission, after***

[16] Refer: Para 61, Section VII of Electricity Act 2003

considering the above proposals and after examining the actual PLF achieved by the plants in operation, decides that a PLF of 26.5% would be reasonable for tariff computation."

As explained earlier, the regulatory commission's orders/government notifications consider data from various sources including wind power developers, NGOs, general public, state utilities, government agencies involved in wind monitoring, etc. and go through an extensive consultation and public hearing before arriving at the Plant Load Factor that reasonably represents the average expected PLF over the term of the PPA. The PLF is also subject to further review as more data becomes available.

Finally, the PLF used by regulatory commission's order strikes a balance between what is achievable (and therefore protect generator's interest) and what should be allowed (and therefore protect the consumer's interest). We therefore believe that it is appropriate to use this PLF in the investment analysis. Further, to take care of uncertainties, the range of PLFs that are indicated in the regulatory commission's orders/government notifications have been used as part of the sensitivity analysis.

6. **The PPs applies ACM0002/ Version 6. The grid EF is calculated for southern regional grid of India and is fixed ex-ante. The PPs use the statistics from CEA database. Simple OM is calculated for years 2002-2005 but year for BM is not clearly mentioned in the PDD. Further clarification is required.**

We thank you for bringing this to our notice and apologize of the omission. The value for BM taken from the CEA database pertains to the year 2004-05[17] (Appendix 15). A copy of this database is also available with the DOE. We request the DOE to confirm this.

7. **Only one parameter, net electricity supplied to the grid, is considered for monitoring. This is net electricity supplied to the grid. According to the validation report (page 14) "the net electricity export to the grid will be reported on monthly basis and cross checked with the invoices raised to KPTCL". This means that measured electricity is the basis for CERs and the invoices are only for crosschecking, though this is not clearly expressed in monitoring information (annex 4 to the PDD). At least two parameters, import and export should be listed in B.7.1 Data and Parameters Monitored" and the third net electricity should be calculated. Roles of invoices should be added in the Annex 4 to the PDD.**

We regret the confusion created due to explanations given in the PDD. The metering system for the project activity consists of one main and one check meter. Both main and check meters are two-way trivector meters capable of recording import and export of electricity and provide output in the form of net electricity supplied to the grid. The Net electricity supplied to the grid is recorded by taking a Joint Meter Reading (JMR) in the presence of Officials from off-taking Utility and Enercon India Limited. The Joint meter reading contains the value of energy imported and exported and the net export to the grid during the recording period. This Joint meter reading is certified by the Executive engineer of the utility and by Enercon Officials. These certified readings are then used by the Discom officials to prepare the tariff invoices. Thus the sole monitoring parameter for the project activity is the net electricity supplied to the grid as mentioned in the JMR, which will be crosschecked with the value mentioned in the invoices.

We appreciate the view of EB and have revised the PDD clearly mentioning the role of invoices in the Annex 4 to the PDD.

For Enercon India Ltd

for **A V Raghavan**

Associate Vice President

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[17] Source: http://www.cea.nic.in, version 1.1 of the baseline

Appendices to the document

Appendix 1 - CERC order dated 24th January 2004

Appendix 2 - KERC order dated 18 January 2005

Appendix 3 – MNRE data showing total potential and installations of wind power

Appendix 4 – Year-wise allotment and commissioned wind power projects in Karnataka

Appendix 5 – Annex to KERC order for BESCOM tariff dated 16th October 2006

Appendix 6 – Southern region power sector profile, Ministry of Power

Appendix 7 – Capacity addition required during 11th plan (refer page 3 of the document)

Appendix 8 – Coal availability in India

Appendix 9 – MNES guidelines on policy

Appendix 10 – KERC order dated 17th September 2003

Appendix 11 – Levelised tariff calculations

Appendix 12 – Backing down of wind projects in Tamil Nadu

Appendix 13 – Chapter 3 of CEA General Review 2006

Appendix 14 – Chapter 5 of CEA General Review 2006

Appendix 15 – CEA CO2 Emission database version 1.1

List of participants involved in the tariff determination process in Karnataka.

Indian Wind Power Association Karnataka Council, Bangalore.
http://www.indianwindpower.com/

Karnataka Renewable Energy Development Ltd. (KREDL)
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Indian wind energy association, New Delhi
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