



**CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006**

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**SECTION A. General description of project activity****A.1 Title of the project activity:**

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Title: Enercon Wind Farm (Hindustan) Ltd in Karnataka

Version: 6.0

Date of completion of PDD: 03/09/2012

A.2. Description of the project activity:

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Objective of the Project

The objective is development, design, engineering, procurement, finance, construction, operation and maintenance of Enercon Wind Farm (Hindustan) Ltd. (EWHPL) 68.8 MW wind power project (“Project”) in the Indian state of Karnataka to provide reliable, renewable power to the Karnataka state electricity grid which is part of the Southern regional electricity grid. The Project will lead to reduced greenhouse gas emissions because it displaces electricity from fossil fuel based electricity generation plants.

Nature of Project

The Project harnesses renewable resources in the region, and thereby displacing non-renewable natural resources thereby ultimately leading to sustainable economic and environmental development. Enercon (India) Ltd (“Enercon”) will be the equipment supplier and the operations and maintenance contractor for the Project. The generated electricity will be supplied to Karnataka Power Transmission Company Ltd (“KPTCL”)/ Bangalore Electricity Supply Company Ltd (“BESCOM”) under a long-term power purchase agreement (PPA). The Project company (EWHPL) is owned by Enercon (India) Ltd and Enercon GmbH.

Contribution to sustainable development

The Project meets several sustainable development objectives including:

- contribution towards the policy desire of Government of India and Government of Karnataka of incremental capacity from renewable sources;
- contribution towards meeting the electricity deficit in Karnataka;
- CO₂ abatement and reduction of greenhouse gas emissions through development of renewable technology;
- reducing the average emission intensity (SO_x, NO_x, PM, etc.), average effluent intensity and average solid waste intensity of power generation in the system;
- conserving natural resources including land, forests, minerals, water and ecosystems; and
- developing the local economy and create jobs and employment, particularly in rural areas, which is a priority concern for the Government of India;

**A.3. Project participants:**

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Name of Party involved (host) indicates a host Party)	Private and/or public entity(ies) project participants (*) (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Government of India (Host)	Enercon (India) Ltd	No
United Kingdom of Great Britain and Northern Ireland	Rabobank International (Private entity)	No

The contact details of the entities are provided in Annex – 1.

A.4. Technical description of the project activity:**A.4.1. Location of the project activity:**

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A.4.1.1. Host Party(ies):

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The host party to the project activity is the Government of India.

A.4.1.2. Region/State/Province etc.:

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The Project is located in the State of Karnataka that forms part of the Southern regional electricity grid of India.

A.4.1.3. City/Town/Community etc:

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The Project is located at Chikkabyaladakere, Kanubehalli, Elladakere and Arasinagundi villages in Chitradurga District and Dasudi, Nelenuru, Ganadu, Annenhalli, Siddapura villages in Tumkur district of Karnataka state in India.

A.4.1.4. Detail of physical location, including information allowing the unique identification of this project activity (maximum one page):

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The project area extends between latitude 13° 31' & 13° 45' North and longitude 76° 30' & 76° 44' East. The Project is connected to the KPTCL 220/66/11 kV substation at Hiriur village. The site is located at a distance of 200 km from Bangalore by road. The nearest railway station is at Bangalore. A location map is attached at Appendix – 1.

The Project consists of 86 E-48 WECs of 800 kW each. The turbines are uniquely identified as EWFHL-01 to EWFHL-86. the details of the physical location are as follows:

S. No	District	Taluka	Village	No. Of WECs
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1	Tumkur	Chikkanayakanahalli	Dasudi	20
		Chikkanayakanahalli	Nelenuru	5
		Chikkanayakanahalli	Ganadu	6
		Gubbi	Annenhalli	6
		Gubbi	Siddapura	9
2	Chitradurga	Hosadurga	Chikkabyaledakere	16
		Hosadurga	Kanubehalli	11
		Hosadurga	Arasinagundi	8
		Hosadurga	Elladakere	5
Total number of wind energy converters (WECs)				86

A.4.2. Category(ies) of project activity:

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The project activity is considered under CDM category zero-emissions ‘**grid-connected electricity generation from renewable sources**’ that generates electricity in excess of 15 MW (limit for small scale project). Therefore as per the scope of the project activity enlisted in the ‘list of sectoral scopes and related approved baseline and monitoring methodologies (version 02 Mar 05/07:23)’, the project activity may principally be categorized in Scope Number 1, Sectoral Scope - Energy industries (renewable/ non-renewable sources).

A.4.3. Technology to be employed by the project activity:

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The Project involves 86 wind energy converters (WECs) of Enercon make (800 kW E-48) with internal electrical lines connecting the Project with local evacuation facility. The WECs generates 3-phase power at 400V, which is stepped up to 33 KV. The Project can operate in the frequency range of 47.5–51.5 Hz and in the voltage range of 400 V \pm 12.5%. The other salient features of the state-of-art-technology are:

- Gearless Construction - Rotor & Generator Mounted on same shaft eliminating the Gearbox.
- Variable speed function – has the speed range of 18 to 33 RPM thereby ensuring optimum efficiency at all times.
- Variable Pitch functions ensuring maximum energy capture.
- Near Unity Power Factor at all times.
- Minimum drawal (less than 1% of kWh generated) of Reactive Power from the grid.
- No voltage peaks at any time.
- Operating range of the WEC with voltage fluctuation of -20 to +20%.
- Less Wear & Tear since the system eliminates mechanical brake, which are not needed due to low speed generator which runs at maximum speed of 33 rpm and uses Air Brakes.
- Three Independent Braking System.
- Generator achieving rated output at only 33 rpm.
- Incorporates lightning protection system, which includes blades.
- Starts generation of power at wind speed of 3 m/s.

Enercon (India) Ltd has secured and facilitated the technology transfer for wind based renewable energy generation from Enercon GmbH, has established a manufacturing plant at Daman in India,



where along with other components the "Synchronous Generators" using "Vacuum Impregnation" technology are manufactured.

A.4.4 Estimated amount of emission reductions over the chosen crediting period:

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Crediting Period for the Project: fixed for 10 years

Years	Annual estimation of emission reductions in tonnes of CO ₂ e
2008	148,858
2009	148,858
2010	148,858
2011	148,858
2012	148,858
2013	148,858
2014	148,858
2015	148,858
2016	148,858
2017	148,858
Total estimated reductions (tonnes of CO ₂ e)	1,488,580
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tonnes of CO ₂ e)	148,858

A.4.5. Public funding of the project activity:

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There is no ODA financing involved in the Project.

SECTION B. Application of a baseline and monitoring methodology

B.1. Title and reference of the approved baseline and monitoring methodology applied to the project activity:

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The approved consolidated baseline and monitoring methodology **ACM0002 Version 6.0** (19 May 2006) has been used. The titles of these baseline and monitoring methodologies are "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" and "Consolidated monitoring methodology for grid-connected electricity generation from renewable sources."

**B.2 Justification of the choice of the methodology and why it is applicable to the project activity:**

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The Project is wind based renewable energy source, zero emission power project connected to the Karnataka state grid, which forms part of the Southern regional electricity grid. The Project will displace fossil fuel based electricity generation that would have otherwise been provided by the operation and expansion of the fossil fuel based power plants in Southern regional electricity grid.

The approved consolidated baseline and monitoring methodology ACM0002 Version 6 is the choice of the baseline and monitoring methodology and it is applicable because:

- the Project is grid connected renewable power generation project activity
- the Project represents electricity capacity additions from wind sources
- the Project does not involve switching from fossil fuel to renewable energy at the site of project activity since the Project is green-field electricity generation capacities from wind sources at sites where there was no electricity generation source prior to the Project, and
- the geographical and system boundaries of the Southern electricity grid can be clearly identified and information on the characteristics of the grid is available.

B.3. Description of the sources and gases included in the project boundary.

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According to ACM0002, for the baseline emission factor, the spatial extent of the project boundary includes the project site and all power plants connected physically to the electricity system that the CDM project power plant is connected to.

The Indian electricity system is divided into five regional grids, viz. Northern, Eastern, Western, Southern, and North-Eastern. Each grid covers several states. As the regional grids are interconnected, there is inter-state and inter-regional exchange. A small power exchange also takes place with neighbouring countries like Bhutan and Nepal.

Power generation and supply within the regional grid is managed by Regional Load Dispatch Centre (RLDC). The Regional Power Committees (RPCs) provide a common platform for discussion and solution to the regional problems relating to the grid. Each state in a regional grid meets its demand with its own generation facilities and also with allocation from power plants owned by the Central Sector such as NTPC and NHPC etc. Specific quotas are allocated to each state from the Central Sector power plants. Depending on the demand and generation, there are electricity exports and imports between states in the regional grid. The regional grid thus represents the largest electricity grid where power plants can be dispatched without significant constraints and thus, represents the “project electricity system” for the Projects. As the Projects are connected to the Southern regional electricity grid, the Southern grid is the “project electricity system”.

Accordingly, the project boundary encompasses the physical extent of the southern regional electricity grid which includes the project site and all power plants connected physically to the electricity system.



	Source	Gas	Included?	Justification/ Explanation
Baseline	Electricity generation from power plants connected to the Southern Grid	CO ₂	Included	Main emission source
		CH ₄	Excluded	This source is not required to be estimated for wind energy projects under ACM0002
		N ₂ O	Excluded	This source is not required to be estimated for wind energy projects under ACM0002
Project Activity	Electricity generation from the Projects	CO ₂	Excluded	Wind energy generation does not have any direct GHG emissions.
		CH ₄	Excluded	
		N ₂ O	Excluded	

B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

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According to ACM0002, for project activities that do not modify or retrofit an existing electricity generation facility, the baseline scenario is the following:

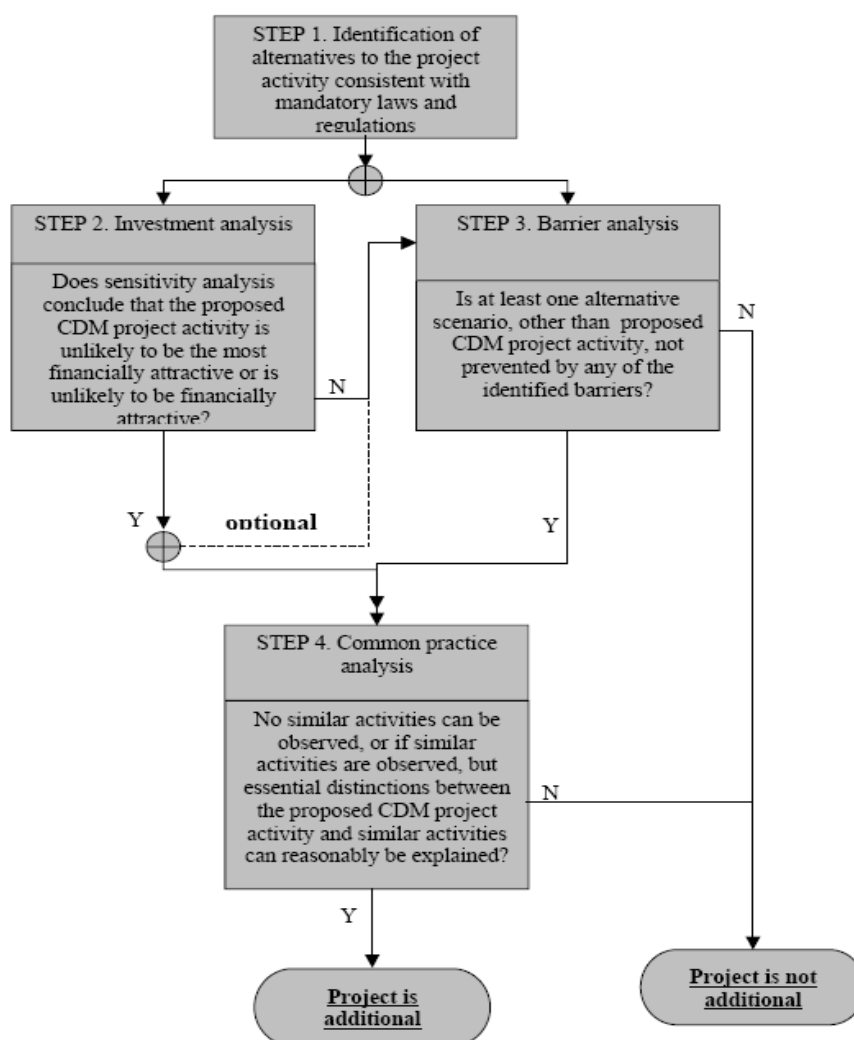
Electricity delivered to the grid by the project would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations described below.

As the Project does not modify or retrofit an existing generation facility, the baseline scenario is the emissions generated by the operation of grid-connected power plants and by the addition of new generation sources. This is estimated using calculation of Combined Margin multiplied by electricity delivered to the grid by the Project.

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity (assessment and demonstration of additionality): >>

The Project start date is prior to the start date of validation of the PDD. Enercon and a CER purchaser had entered into an Emission Reduction Purchase Agreement dated 7 December 2005 for purchase of emission reductions from the Project, which is prior to the start date of the Project.

The latest additionality tool i.e. Tool for the demonstration and assessment of additionality version 3.0 approved by CDM Executive Board in its 29th meeting is used to demonstrate project additionality.



Step 1: Identification of alternatives to the project activity consistent with current laws and regulations

Sub-step 1a. Define alternatives to the project activity:

1. Identify realistic and credible alternative(s) available to the project participants or similar project developers that provide outputs or services comparable with the proposed CDM project activity. These alternatives are to include:

- The proposed project activity not undertaken as a CDM project activity;
- All other plausible and credible alternatives to the project activity that deliver outputs and on services (e.g. electricity, heat or cement) with comparable quality, properties and application areas;



- If applicable, continuation of the current situation (no project activity or other alternatives undertaken).

Alternative(s) available to the project participants or similar project developers include:

- (a) The Project is not undertaken as a CDM project activity.
- (b) Setting up of comparable utility scale fossil fuel fired or hydro power projects that supply to the Karnataka grid under a PPA.

Continuation of the current situation where no project activity or any of the above Alternatives are undertaken would not be applicable as Karnataka had energy (MU) shortages of 0.7% and peak (MW) shortages of 9.8% in 2005-06 (Source: Southern Region Power Sector Profile, August 2006, Ministry of Power).

Outcome of step 1 a:

Alternatives a and b, as identified above are realistic and credible alternatives to the project activity.

Sub-step 1b. Enforcement of applicable laws and regulations

2. The alternative(s) shall be in compliance with all applicable legal and regulatory requirements, even if these laws and regulations have objectives other than GHG reductions, e.g. to mitigate local air pollution. This sub-step does not consider national and local policies that do not have legally-binding status.
3. If an alternative does not comply with all applicable legislation and regulations, then show that, based on an examination of current practice in the country or region in which the law or regulation applies, those applicable legal or regulatory requirements are systematically not enforced and that non-compliance with those requirements is widespread in the country. If this cannot be shown, then eliminate the alternative from further consideration.
4. If the proposed project activity is the only alternative amongst the ones considered by the project participants that is in compliance with all regulations with which there is general compliance, then the proposed CDM project activity is not additional.

There are no legal and regulatory requirements that prevent Alternatives (a) and (b) from occurring.

Outcome of step 1 b

Both alternative a and alternative b are in compliance with mandatory laws and regulations taking into account the enforcement in the region or country and EB decision on national and sectoral policies. Hence Alternative a and b as identified in the step 1a are realistic and credible alternatives to the project activity.

Proceed to Step 2 (Investment analysis) or Step 3 (Barrier analysis). (Project participants may also select to complete both steps 2 and 3.)

Step 2: Investment Analysis

Determine whether the proposed project activity is the economically or financially less attractive than other alternatives without the revenue from the sale of certified emission reductions (CERs). To conduct the investment analysis, use the following sub-steps:

Sub-step 2a. - Determine appropriate analysis method



1. Determine whether to apply simple cost analysis, investment comparison analysis or benchmark analysis (sub-step 2b). If the CDM project activity generates no financial or economic benefits other than CDM related income, then apply the simple cost analysis (Option I). Otherwise, use the investment comparison analysis (Option II) or the benchmark analysis (Option III).

Sub-step 2b. – Option I. Apply simple cost analysis

2. Document the costs associated with the CDM project activity and demonstrate that the activity produces no economic benefits other than CDM related income.

Sub-step 2b. – Option II. Apply investment comparison analysis

3. Identify the financial indicator, such as IRR, NPV, cost benefit ratio, or unit cost of service (e.g., levelized cost of electricity production in \$/kWh or levelized cost of delivered heat in \$/GJ) most suitable for the project type and decision-making context.

Sub-step 2b. – Option III. Apply benchmark analysis

4. Identify the financial indicator, such as IRR, NPV, cost benefit ratio, or unit cost of service (e.g., levelized cost of electricity production in \$/kWh or levelized cost of delivered heat in \$/GJ) most suitable for the project type and decision context.

Option I – Simple cost analysis is not applicable as the project activity sells electricity to the grid and obtains economic benefits in the form of electricity tariffs.

Enercon proposes to use **Option III – Benchmark analysis** and the financial indicator that is identified is the post-tax return on equity or the equity IRR.

The expected cost of equity and weighted average of cost of capital (WACC) for the power generating industry in India has been calculated using CAPM approach (Detailed calculations are provided in Annex 7) supported by data derived from Bloomberg and other relevant sources.

While carrying out the investment analysis, we had initially used the 16% post tax equity return benchmark that is considered by various regulatory commissions for determining the tariff applicable to wind power projects. Without CDM revenues, it was not possible for us to implement the project, as the IRR of our project was significantly below the benchmark; we were able to come close to the benchmark only with the support of CDM revenues. Therefore we entered into a forward emission reduction purchase agreement (ERPA) in December 2005, i.e. before the project start date of March 2006, to secure the CDM revenues and ensure viability of this investment.

In EB-40, the Executive Board ruled against suitability of CERC benchmark of 16% as that value is used in tariff determination for CDM projects and for non CDM projects. We were asked by EB to clarify “Given the calculated IRR for the project activity how it can be demonstrated that investment would not be made without the benefits of CDM”.

We clarified in our submission taken up in EB-41 that, it was not possible for us to undertake the project activity without the benefits of CDM as the IRRs of this project was not only lower than the benchmark, also the IRRs and other factors like Debt Service Coverage Ratio (DSCR) do not meet the credit requirements of banks. To evidence this, we explained the lending criteria applied by bank and how the project was not able to meet these criteria without the support of CDM. We also drew attention of the EB to the fact that our project IRR was even lower than the bank PLR (Prime Lending Rate). At the time of project start date the Bank PLR was between 10.25% - 10.75% [Source: Reserve Bank of India, <http://www.rbi.org.in/scripts/WSSView.aspx?Id=9359>), whereas our Project IRR was (without CDM) 8.55%.



Even taking the actual starting interest rate of 8.5% , a project IRR of just 8.55% would not provide the lenders with adequate cushion for approval especially considering that there is always a chance of a downside in project performance as well as an increase in interest rate (the interest rate for the project is now already up to 9%). Banks in India typically require a minimum DSCRs (debt service coverage ratio, defined as Net Cash from Operations divided by debt servicing of a year) of about 1.5x (same has been considered by this project lending bank, PNB, please see Annex 5), which is required to be satisfied after adjusting for any downside. The average DSCR of our project in base case is 1.44x, which is below 1.5x minimum requirement, after adjusting for a 10% downside in generation (which is likely to happen and has happened in the past) the DSCR further comes down to 1.22x, which is well below the lender's requirement. With CDM base case the average DSCR improved to 1.61x, which lenders found acceptable.

We would also like to submit that as per Guidance to investment analysis issued in EB 41 (paragraph 11), the weighted average cost of capital can be considered as appropriate benchmark for project IRR. The tool for demonstration and assessment of additionality [para-5, sub step 2(b)] states that in such cases (where the project has more than one potential developer) the benchmark can not be based on internal cost of equity or WACC and shall be based on parameters that are standard in the market, considering the specific characteristics of the project type. Hence, we have not used company or project specific parameters for the calculation of the benchmark (such as company WACC, project and company specific interest rates, etc.).

Accordingly, the weighted average cost of capital applicable to the project type has been considered. Weighted average cost of capital (WACC) is calculated as weighted average cost of equity and cost of debt as illustrated below

$$\text{WACC} = [D / (D+E)] * [\text{Cost of Debt}] + [E / (D+E)] * [\text{Cost of Equity}]$$

Cost of Debt:

Cost of debt is defined as the rate at which lender's agree to lend money to a project. The additionality tool and the guidance to investment analysis clarify that for projects that benchmark for project with more than one potential developer should not be based on project specific parameters but should represent the standard in the market. Accordingly, the bank prime lending prevailing at the time of project start date has been considered as the cost of debt. The prime lending rate at the time of investment was in the range of 10.25% - 10.75% [Source: Reserve Bank of India (RBI), <http://www.rbi.org.in/scripts/WSSView.aspx?Id=9359>], the average PLR of 10.50% has been considered as the cost of debt.

Cost of Equity:

The cost of equity has been determined using the Capital Asset Pricing Model (CAPM) considering Beta values of all power generating companies in India that were listed at the time of this investment. Detailed calculations of cost of equity and WACC along with an elaboration of the approach are provided in Annex 7.

As can be seen, the benchmark WACC works out to **12.13%**.



The WACC has been calculated considering bank PLR as the cost of debt, this is in accordance with additionality tool version 5 sub-step 2(b) Para 5 that mandates use of standard parameters for benchmark calculation. It may be noted that the actual cost of debt for the project is 8.5%, if the actual cost of debt is considered, the WACC works out to 10.9%.

In accordance with EB guidance (additionality tool version 5 and guidance for investment analysis – EB 41), we have considered the WACC of 12.13% as the benchmark. However, it is important to note that even if the actual cost of debt were to be considered for WACC calculations, the project IRR is still lower than the WACC.

Sub-step 2c. Calculation and comparison of financial indicators (only applicable to options II and III):

1. Calculate the suitable financial indicator for the proposed CDM project activity and, in the case of Option II above, for the other alternatives. Include all relevant costs (including, for example, the investment cost, the operations and maintenance costs), and revenues (excluding CER revenues, but including subsidies/fiscal incentives where applicable), and, as appropriate, non-market cost and benefits in the case of public investors.
2. Present the investment analysis in a transparent manner and provide all the relevant assumptions in the CDM-PDD, so that a reader can reproduce the analysis and obtain the same results. Clearly present critical techno-economic parameters and assumptions (such as capital costs, fuel prices, lifetimes, and discount rate or cost of capital). Justify and/or cite assumptions in a manner that can be validated by the DOE. In calculating the financial indicator, the project's risks can be included through the cash flow pattern, subject to project-specific expectations and assumptions (e.g. insurance premiums can be used in the calculation to reflect specific risk equivalents).
3. Assumptions and input data for the investment analysis shall not differ across the project activity and its alternatives, unless differences can be well substantiated.
4. Present in the CDM-PDD submitted for validation a clear comparison of the financial indicator for the proposed CDM activity and:
5. The alternatives, if Option II (investment comparison analysis) is used. If one of the other alternatives has the best indicator (e.g. highest IRR), then the CDM project activity can not be considered as the most financially attractive;
6. The financial benchmark, if Option III (benchmark analysis) is used. If the CDM project activity has a less favourable indicator (e.g. lower IRR) than the benchmark, then the CDM project activity cannot be considered as financially attractive.

The key assumptions used for calculating the benchmark (post-tax equity IRR) are set out below. These are the assumption on which the attached financial model based.

Capacity of Machines in kW	800
Number of Machines	86
Project Capacity in MW	68.80
Project Commissioning Date	28-Dec-06
Project Cost per MW (Rs. In Millions)	47.4



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Operations	
Plant Load Factor	26.5%
Insurance Charges @ % of capital cost	0.18%
Operation & Maintenance Cost base year @ % of capital cost	1.25%
% of escalation per annum on O & M Charges	5.0%

Tariff	
Base year Tariff for 10 years - Rs./kWh	3.40
Annual Escalation (Rs./kWh per Year)	0.00
Tariff applicable after 10 years (Rs/kWh)	Cost plus 16% return on equity

Project Cost	Rs Million
Land and Infrastructure, Generator & Electrical Equipments, Mechanical Equipments, Civil Works, Instrumentation & Control, Other Project Cost, Pre operative Expenses, etc.	
Total Project Cost	3,263

Means of Finance		Rs Million
Own Source	30%	979
Term Loan	70%	2,284
Total Source		3,263
Terms of Loan		
Interest Rate	8.50%	
Tenure	10	Years
Moratorium	6	Months

Income Tax Depreciation Rate (Written Down Value basis)	
on Wind Energy Generators	80%
On other Assets	10%
Book Depreciation Rate (Straight Line Method basis)	
On all assets	7.86%
Book Depreciation up to (% of asset value)	90%

Income Tax	
Income Tax rate	30%
Minimum Alternate Tax	10%
Surcharge	10%



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Cess	2%
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Working capital	
Receivables (no of days)	45
O & m expenses (no of days)	30
Working capital interest rate	12%

CER Revenues	
CER Price in US\$	10
Exchange rate Rs./US\$*	45.34

* RBI reference rate as of 15 November 2006

Crediting period starts	1-Jul-07
Length of Crediting period	10

Baseline Emission Factor for Southern Region (tCO ₂ /GWh)	932.04
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The equity IRR for the Project (without CDM revenues) is 11.7 % and project IRR is 8.55%. After considering CDM revenues, the equity and project IRRs improve to 16.5% and 10.30% respectively.

As explained under sub-step 2(b), the benchmark WACC for the project works out to 12.13%, as can be seen the project IRR is lower than the benchmark. Even when the actual cost of debt is considered the project IRR remains lower than the WACC. This analysis holds true even with the sensitivity.

We now present the clarifications to queries raised in EB-41.

Reasons why the project could not have been financed and invested even if the project IRR without CDM (8.55%) was higher than the actual interest rate (8.5%).

We would like to submit that is that this minimal cushion is not enough for lenders, in fact there is virtually no cushion against any downward slide as the numbers are essentially the same. The project IRR is 8.55% whereas the interest rate is 8.5%. When the project IRR is equal to or just marginally above the interest rate, the lenders stand the risk of suffering even if there is a small downside in the project's performance. Just a 10% decrease in estimated generation of power (which can easily happen and has happened in the past), the project IRR drops to 7.14% which is lower than the interest rate for the project.

In such cases, lending banks also face the risk of possible increase in interest rates, as any minor variation in interest rate can jeopardize the project's capacity to meet its interest and loan repayment obligations. To illustrate, we would like draw attention to the fact the current interest rate for the project is 9% (interest rates are reset periodically) which is higher than the project IRR. Therefore, to safeguard against reasonable downsides in project performance and changes in interest rate, lenders consider an average DSCR of at least 1.5x, a project IRR of above 12% which clearly implies that a project IRR marginally above interest rate not enough for them. We have also



included a communication from our lenders Rabobank that explains the reasons why banks are not satisfied simply with project IRR being marginally higher than interest rate (Please see letter from Rabobank, attached as Annex 6).

Also, projects that generate returns that are barely able to meet the loan costs (leave alone provide any returns to equity investors) are not worthwhile for equity investors like us to invest in. To ensure investment in the project and continued operation, equity investors require an adequate return, and the banks also recognize the same. Please refer to letter from project lender (Punjab National Bank, attached as Annex 5) which also mentions the equity IRR criteria for the project.

Principles of Corporate Finance state: Projects raise money from both equity investors and lenders, both groups of investors make their investments expecting to make a return. The expected return for equity investors includes a premium for the equity risk in the investment and is known as Cost of Equity. Similarly; lenders expected return includes a premium for undertaking the risk that the project could default in repayments, and is referred as the Cost of Debt [Page 186, 187 attached as Appendix 5]. In fact, “the first principle of Corporate Finance” states that investment should be made only in projects that yield a return greater than the minimum acceptable hurdle rate; the hurdle rate should be higher for riskier projects and should reflect the financing mix” [Page 185, attached as Appendix 4]. Therefore the costs of equity and cost of debt, collectively (and not the interest rate alone) represent what the project needs to make on its investment in order for it to be considered as investment worthy.

In summary, Lenders are not willing to finance projects that have financial parameters that are significantly lower than the lending criteria. Further, the parameter for investment is the equity IRR, without which the investor will not invest in any case, and the project will not even be referred to lenders for consideration.

Sub-step 2d. Sensitivity analysis (only applicable to options II and III):

5. Include a sensitivity analysis that shows whether the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions. The investment analysis provides a valid argument in favor of additionality only if it consistently supports (for a realistic range of assumptions) the conclusion that the project activity is unlikely to be the most financially attractive (as per step 2c para 8a) or is unlikely to be financially attractive (as per step 2c para 8b).

Sensitivity analysis of the Equity IRR to the Plant Load Factor (the most critical assumption) has been carried out considering a plant load factor of 23% and 28% (the range indicated in KERC Order dated 18 January 2005). Plant Load Factor is the key variable encompassing variation in wind profile, variation in off-take (including grid availability) including machine downtime. The post tax Equity IRRs at the stated PLFs are as follows:

Sensitivity	PLF at 23%	PLF at 28%
Post tax Equity IRR without CER revenues	7.0%	13.9%
Post tax Project IRR without CER revenues	6.67%	9.35%

**Outcome of step 2**

As can be seen from above, the Project is not the most financially attractive (as per step 2c para 8a) we proceed to Step 4 (Common practice analysis).

Step 4. Common practice analysis

Sub-step 4a. Analyze other activities similar to the proposed project activity:

Sub-step 4b. Discuss any similar options that are occurring:

1. Provide an analysis of any other activities implemented previously or currently underway that are similar to the proposed project activity. Projects are considered similar if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc. Other CDM project activities are not to be included in this analysis. Provide quantitative information where relevant.
2. If similar activities are widely observed and commonly carried out, it calls into question the claim that the proposed project activity is financially unattractive (as contended in Step 2) or faces barriers (as contended in Step 3). Therefore, if similar activities are identified above, then it is necessary to demonstrate why the existence of these activities does not contradict the claim that the proposed project activity is financially unattractive or subject to barriers. This can be done by comparing the proposed project activity to the other similar activities, and pointing out and explaining essential distinctions between them that explain why the similar activities enjoyed certain benefits that rendered it financially attractive (e.g., subsidies or other financial flows) or did not face the barriers to which the proposed project activity is subject.
3. Essential distinctions may include a serious change in circumstances under which the proposed CDM project activity will be implemented when compared to circumstances under which similar projects were carried out. For example, new barriers may have arisen, or promotional policies may have ended, leading to a situation in which the proposed CDM project activity would not be implemented without the incentive provided by the CDM. The change must be fundamental and verifiable.

We analyze the extent to which wind energy projects have diffused in the electricity sector in Karnataka. In 2004 – 05, wind electricity generation was 485.57 GWh and the total electricity availability at bus-bar in the state of Karnataka was 33523.92 GWh (Source: CEA General Review 2006). This shows that wind energy accounted for 1.45% of electricity generation in the state of Karnataka, and was therefore not common practice.

Installed capacity of wind energy generation sources stood at 276 MW as of 31 March 2005 (Source: CEA General Review 2006). There are approximately 201 MW wind energy projects that are currently in the CDM pipeline (UNFCCC website) and more are expected to follow.

Further, all other wind projects in Karnataka to the best of our knowledge, as per the CDM pipeline, are substantially dependent on CDM mechanism.

Outcome of step 4

Thus wind projects without CDM is not common practice.



Sub-steps 4a and 4b are satisfied and therefore the project activity is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

>>

According to the approved baseline methodology ACM0002, the emission reductions ER_y by the project activity during a given year “y”¹ is

$$ER_y = BE_y - PE_y - Ly \dots \dots \dots (1)$$

Where: BE_y is baseline emissions
 PE_y is project activity emissions and;
 Ly is the amount of emissions leakage resulting from the project activity.

Baseline Emissions for the amount of electricity supplied by project activity, BE_y is calculated as

$$BE_y = EG_y * EF_y \dots \dots \dots (2)$$

where EG_y is the electricity supplied to the grid, EF_y is the CO₂ emission factor of the grid as calculated below.

The emission factor EF_y of the grid is represented as a combination of the Operating Margin (OM) and the Build Margin (BM). Considering the emission factors for these two margins as $EF_{OM,y}$ and $EF_{BM,y}$, then the EF_y is given by:

$$EF_y = w_{OM} * EF_{OM,y} + w_{BM} * EF_{BM,y} \dots \dots \dots (2)$$

with respective weight factors w_{OM} and w_{BM} (where $w_{OM} + w_{BM} = 1$).

The Operating Margin emission factor

As per ACM0002, dispatch data analysis should be the first methodological choice. However, this option is not selected because the information required to calculate OM based on dispatch data is not available in the public domain for the Southern electricity regional grid.

The Simple Operating Margin approach is appropriate to calculate the Operating Margin emission factor applicable in this case. As per ACM 0002 the Simple OM method can only be used where low cost must run resources constitute less than 50% of grid generation based on average of the five most recent years. The generation profile of the Southern grid in the last five years is as follows:

¹ Throughout the document, the suffix y denotes that such parameter is a function of the year y, thus to be monitored at least annually.



Generation in GWh	2004-05	2003-04	2002-03	2001-02	2000-01
Low cost/must run sources					
Hydro	24,951	16,943	18,288	26,260	29,902
Wind & Renewables	3,256	1,865	1,607	1,456	1,262
Nuclear	4,408	4,700	4,390	5,244	4,331
Other sources					
Coal	99,010	98,435	92,053	84,032	83,292
Diesel	2,434	3,295	4,379	4,155	2,868
Gas	12,428	14,214	13,950	10,331	7,132
Total Generation	146,487	139,451	134,667	131,478	128,787
Low cost/must run sources	32,615	23,508	24,285	32,960	35,496
Low cost/must run sources	22%	17%	18%	25%	28%

Source: Table 3.4 of CEA General Review 2004-05, 2003-04, 2002-03, 2001-02, 2000-01

From the available information it is clear that low cost/must run sources account for less than 50% of the total generation in the Southern grid in the last five years. Hence the Simple OM method is appropriate to calculate the Operating Margin Emission factor applicable.

Build Margin Emission Factor

The Build Margin emission factor $EF_{BM,y}$ (tCO₂/GWh) is given as the generation-weighted average emission factor of the selected representative set of recent power plants represented by the 5 most recent plants or the most recent 20% of the generating units built (summation is over such plants specified by k):

$$EF_{BM,y} = [\sum_i F_{i,m,y} * COEF_i] / [\sum_k GEN_{k,m,y}] \dots \dots \dots (5)$$

The summation over i and k is for the fuels and electricity generation of the plants in sample m mentioned above.

The choice of method for the sample plant is the most recent 20% of the generating units built as this represents a significantly larger set of plants for a large regional electricity grid having a large number of power plants connected to it and is therefore appropriate.

The Central Electricity Authority, Ministry of Power, Government of India has published a database of Carbon Dioxide Emission from the power sector in India based on detailed authenticated information obtained from all operating power stations in the country. This database i.e. The CO₂ Baseline Database provides information about the Operating Margin and Build Margin Emission Factors of all the regional electricity grids in India. The Operating Margin in the CEA database is calculated ex ante using the Simple OM approach and the Build Margin is calculated ex ante based on 20% most recent capacity additions in the grid based on net generation as described in ACM0002. We have, therefore, used the Operating Margin and Build Margin data published in the CEA database, for calculating the Baseline Emission Factor.

Combined Margin Emission Factor



As already mentioned, baseline emission factor (EF_y) of the grid is calculated as a combined margin (CM), calculated as the weighted average of the operating margin (OM) and build margin (BM) factor. In case of wind power projects default weights of 0.75 for EF_{OM} and 0.25 for EF_{BM} are applicable as per ACM0002. No alternate weights are proposed.

Using the values for operating margin and build margin emission factors provided in the CEA database and their respective weights for calculation of combined margin emission factor, the baseline carbon emission factor (CM) is 932.04 tCO₂e/GWh or 0.93204 tCO₂e/MWh.

Project Emissions:

The project activity uses wind power to generate electricity and hence the emissions from the project activity are taken as nil.

$$PE_y = 0$$

Leakage:

Emissions Leakage on account of the project activity is ignored in accordance with ACM0002.

$$L_y = 0$$

B.6.2. Data and parameters that are available at validation:

>>

Data / Parameter:	$EF_{OM,y}$						
Data unit:	tCO ₂ e/MWh						
Description:	Operating Margin Emission Factor of Southern Regional Electricity Grid						
Source of data used:	<p>“CO₂ Baseline Database for Indian Power Sector” published by the Central Electricity Authority, Ministry of Power, Government of India.</p> <p>The “CO₂ Baseline Database for Indian Power Sector” is available at www.cea.nic.in</p>						
Value applied:	<table border="1"> <tr> <td>2002 – 03</td><td>0.9970</td></tr> <tr> <td>2003 – 04</td><td>1.0094</td></tr> <tr> <td>2004 – 05</td><td>1.0038</td></tr> </table>	2002 – 03	0.9970	2003 – 04	1.0094	2004 – 05	1.0038
2002 – 03	0.9970						
2003 – 04	1.0094						
2004 – 05	1.0038						
Justification of the choice of data or description of measurement methods and procedures actually applied :	Operating Margin Emission Factor has been calculated by the Central Electricity Authority using the simple OM approach in accordance with ACM0002.						



Data / Parameter:	$EF_{BM,y}$		
Data unit:	tCO ₂ e/MWh		
Description:	Build Margin Emission Factor of Southern Regional Electricity Grid		
Source of data used:	<p>“CO₂ Baseline Database for Indian Power Sector” published by the Central Electricity Authority, Ministry of Power, Government of India.</p> <p>The “CO₂ Baseline Database for Indian Power Sector” is available at www.cea.nic.in</p>		
Value applied:	2004 – 05	0.718	
Justification of the choice of data or description of measurement methods and procedures actually applied:	Build Margin Emission Factor has been calculated by the Central Electricity Authority in accordance with ACM0002.		

B.6.3 Ex-ante calculation of emission reductions:

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Ex-ante calculation of emission reductions is equal to ex-ante calculation of baseline emissions as project emissions and leakage are nil.

Baseline emission factor (combined margin)
= 932.04 tCO₂e/GWh

Annual electricity supplied to the grid by the Project
= 68.8 MW (Capacity) x 26.5% (PLF) x 8760 (hours) / 1000 GWh
= 159.712 GWh

Annual baseline emissions
= 932.04 tCO₂e/GWh x 159.712 GWh
= 148,858 tCO₂e

B.6.4 Summary of the ex-ante estimation of emission reductions:

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Year	Estimation of project activity emissions (tonnes of CO ₂ e)	Estimation of baseline emissions (tonnes of CO ₂ e)	Estimation of leakage (tonnes of CO ₂ e)	Estimation of overall emission reductions (tonnes of CO ₂ e)
2008	0	148,858	0	148,858
2009	0	148,858	0	148,858
2010	0	148,858	0	148,858
2011	0	148,858	0	148,858



Year	Estimation of project activity emissions (tonnes of CO ₂ e)	Estimation of baseline emissions (tonnes of CO ₂ e)	Estimation of leakage (tonnes of CO ₂ e)	Estimation of overall emission reductions (tonnes of CO ₂ e)
2012	0	148,858	0	148,858
2013	0	148,858	0	148,858
2014	0	148,858	0	148,858
2015	0	148,858	0	148,858
2016	0	148,858	0	148,858
2017	0	148,858	0	148,858
Total (tonnes of CO₂e)	0	1,488,580	0	1,488,580

B.7 Application of the monitoring methodology and description of the monitoring plan:**B.7.1 Data and parameters monitored:**

>>	
Data / Parameter:	EGy
Data unit:	MWh (Mega-Watt hour)
Description:	Net electricity supplied to the grid by the Project
Source of data to be used:	Electricity supplied to the grid as per two joint meter readings (Form B) taken at 33 kV metering point.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Annual electricity supplied to the grid by the Project = 68.8 MW (Capacity) x 26.5% (PLF) x 8760 (hours) MWh = 159,712 MWh
Description of measurement methods and procedures to be applied:	<p>Monitoring: The procedures for metering and meter reading will be as per the provisions of the power purchase agreement and details of metering has been explained in monitoring plan in section B.7. 2. Metering system for the project activity consists of two sets of main and check meters at 33 kV metering location. Both sets of meters are two-way trivector meters capable of recording import and export of electricity.</p> <p>In addition to this there is one set of main and check meter (bulk meter) at 220 kV metering point at the Enercon India Limited (hereafter referred as “Enercon” in the revised monitoring plan) substation. The bulk meter is connected to the machines of the project activity and the machines commissioned by the other project developers. Therefore in order to determine the net electricity supplied to the grid by the project activity at high voltage (220 kV) side of Enercon substation, the KPTCL/Discom (hereafter referred as “state utility” in the revised monitoring plan) applies the transmission loss between 220 kV metering point at Enercon substation at Dasudi village and meter reading recorded at the 33 kV metering points for all the machines that are connected to 220 kV bulk meter at</p>



	<p>Enercon substation. The transmission loss calculated by the state utility is endorsed / confirmed jointly by the representatives of Enercon and the state utility. The transmission loss applied to the project activity by the state utility is reflected in the JMR (Form B) recorded at 33kV metering point. Refer Appendix 1 for location of metering points at 33kV and 220 kV.</p> <p>Frequency of recording data: Monthly</p> <p>Recording: The values of net electricity supplied to the grid is sourced from two JMR for 56.8 MW and 12 MW at 33 kV metering point.</p> <p>Responsibility: Joint responsibility of Enercon and state utility.</p> <p>Refer section B.7.2 and Annex – 4 for an illustration of the provisions for measurement methods.</p>
QA/QC procedures to be applied:	QA/QC procedures will be as implemented by state utility pursuant to the provisions of the power purchase agreement except or otherwise explicitly stated in the PDD. The values of net electricity supplied to the grid mentioned in the two JMRs of the project for 56.8 MW and 12 MW at 33kV metering point can be cross checked with values mentioned in the invoice raised on the state utility. Refer Annex – 4 for an illustration of the provisions for QA/QC procedures. Refer Appendix 1 for location of metering points at 33kV and 220 kV.
Any comment:	The data for net electricity supplied to the grid will be archived on electronic media as well as on paper. The archive will be kept for the period up to two years after the completion of the crediting period.

Data / Parameter:	EGexport
Data unit:	MWh (Mega-Watt hour)
Description:	Summation of electricity Export recorded at meters (two main and two check) connecting 86 machines of the project activity and can be sourced from two JMR issued by BESCO for 56.8 MW and 12 MW at 33 kV metering point.
Source of data to be used:	Electricity export to the grid as per two joint meter readings (FormB) taken at 33 kV metering point.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	This value will be taken from the JMR (Form B) taken at 33kV metering point and will be applied directly.
Description of measurement methods and procedures to be applied:	<p>Monitoring: Electricity export to the grid will be recorded by the meters (two main and two check) connecting 86 turbines at 33kV point. Refer section B.7.2 and Annex – 4 for an illustration of the provisions for measurement methods.</p> <p>Frequency of recording data: Monthly</p> <p>Recording: The values electricity export to the grid is sourced from two JMR for 56.8 MW and 12 MW at 33 kV metering point.</p> <p>Responsibility: Joint responsibility of Enercon and state utility</p>



QA/QC procedures to be applied:	QA/QC procedures will be as implemented by state utility and the PP except or otherwise explicitly stated in the PDD. Refer Annex – 4 for an illustration of the provisions for QA/QC procedures.
Any comment:	The data will be archived on electronic media as well as on paper. The archive will be kept for the period up to two years after the completion of the crediting period.

Data / Parameter:	EGimport
Data unit:	MWh (Mega-Watt hour)
Description:	Summation of electricity Import recorded at the meters (two main and two check) connecting 86 machines of the project activity and can be sourced from two JMR issued by BESCO for 56.8 MW and 12 MW at 33 kV metering point.
Source of data to be used:	Electricity import from the grid as per two joint meter reading taken at 33kV metering point.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	This value will be taken from the JMR (Form B) taken at 33 kV metering point and will be applied directly.
Description of measurement methods and procedures to be applied:	<p>Monitoring: Electricity import from the grid will be recorded by meters (two main and two check) connected to the 86 machines at 33kV point. Refer section B.7.2 and Annex – 4 for an illustration of the provisions for measurement methods.</p> <p>Frequency of recording data: Monthly</p> <p>Recording: The values electricity import to the grid is sourced from two JMR for 56.8 MW and 12 MW at 33 kV metering point.</p> <p>Responsibility: Joint responsibility of Enercon and state utility</p>
QA/QC procedures to be applied:	QA/QC procedures will be as implemented by state utility and the PP except or otherwise explicitly stated in the PDD. Refer section B.7.2 Annex – 4 for an illustration of the provisions for QA/QC procedures.
Any comment:	The data will be archived on electronic media as well as on paper. The archive will be kept for the period up to two years after the completion of the crediting period.

Data / Parameter:	TE
Data unit:	MWh (Mega-Watt hour)
Description:	Transmission loss for export between the metering location at 33 kV point and the metering location at 220 kV at the Enercon substation.
Source of data to be used:	Transmission Loss for export will be sourced from the joint meter reading (Form B) taken at 33kV metering point for the project activity.
Value of data applied for the purpose of calculating expected	This value is certified by the State utility in the JMR (Form B). This value will be directly sourced from the JMRs (Form B).



emission reductions in section B.5	
Description of measurement methods and procedures to be applied:	<p>Monitoring: Transmission loss between metering location at 33 kV and the metering location at 220 kV at Enercon substation is applied to the meter reading taken at meters connected at 33 KV point for the project activity.</p> <p>Enercon Substation is connected to the machines of the project activity and the machines commissioned by the other project owners. Therefore transmission loss is applied by the state utility as reflected in the JMR (Form B) taken at 33kV point. The JMR is signed by the representatives of Enercon and the state utility. Refer section B.7.2 and Annex – 4 for an illustration of the provisions for measurement methods.</p> <p>Frequency of recording data: Monthly</p> <p>Recording: The value of transmission loss is sourced from two JMR for 56.8 and 12 MW at 33 kV metering point.</p> <p>Responsibility: Joint responsibility of Enercon and state utility</p> <p>Refer section B.7.2 and Annex – 4 for an illustration of the provisions for measurement methods.</p>
QA/QC procedures to be applied:	QA/QC procedures will be as implemented by state utility and the PP. Refer section B.7.2 and Annex – 4 for an illustration of the provisions for QA/QC procedures.
Any comment:	The data will be stored in hard format and values will be taken from JMR.

The data will be stored in hard format and soft format by PP (Enercon) at the project site office. Joint meter reading is taken in the presence of the persons representing Enercon [Operation and Maintenance Contractor]. The archive will be kept for the period up to two years after the completion of the crediting period.

B.7.2 Description of the monitoring plan:

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Approved monitoring methodology ACM0002 / Version 06 Sectoral Scope: 1, “Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources”, by CDM - Meth Panel is proposed to be used to monitor the emission reductions.

This approved monitoring methodology requires monitoring of the following:

- Electricity generation from the project activity; and
- Operating margin emission factor and build margin emission factor of the grid, where *ex post* determination of grid emission factor has been chosen

Since the baseline methodology is based on ex ante determination of the baseline, the monitoring of operating margin emission factor and build margin emission factor is not required. There are two main and check meters dedicated to project activity at 33 kV metering point for the project activity. The one set of main and check meter is connected to 56.8 MW and other set of the main and check meter is connected to 12 MW of the project activity. In addition to this there is one set of main and check meter (bulk meter) at 220 kV metering point at the Enercon substation is connected to the



machines of the project activity and the machines commissioned by the other project developers. Therefore in order to determine the net electricity supplied to the grid by the project at 220 kV at the Enercon substation, the state utility applies the transmission loss to the meter reading recorded at the 33 kV metering point.

The transmission loss calculated by the state utility is endorsed / confirmed jointly by the representatives of Enercon and the state utility. The transmission loss applied to the project activity by the state utility is reflected in the JMR (Form B) recorded at 33kV metering point. Net electricity supplied to the grid is calculated by applying transmission loss to the meter readings taken at 33 kV metering location of the project activity.

The procedure for calculation of transmission loss as given in the PPA is set-out below:

$$Z = \frac{(X_1 + X_2 + X_3 + X_4 + \dots, X_n) - Y}{(X_1 + X_2 + X_3 + X_4 + \dots, X_n)} \times 100$$

Where,

Z = Percentage transmission loss for export incurred in transmission line between the meters located at 33 kV metering point (including the machines of the project activity and other project developers) and the meters located at 220kV metering point (bulk meter: main and check) at high voltage side of receiving sub-station. **Refer Appendix 1 for schematic of the flow diagram.**

Summation of meter readings at 33 kV metering points for all the project developers connected to receiving substation (including the machines of the project activity and other project developers)

$$= (X_1 + X_2 + X_3 + X_4 + \dots, X_n)$$

X_i = Energy Export Reading (X_i) noted at energy meter installed at 33kV metering point where i vary from 1 to n which represents the meters connected to project activity and other project developers. $X_1, X_2, X_3, \dots, X_n$ are the meters that are installed at 33kV metering point (including the machines of the project activity and other project developers) and further connected to the receiving substation at 220 kV by internally connected lines. **Refer Appendix 1 for schematic of the flow diagram**

Y = Energy Export Reading at bulk meter installed at high voltage side of transformer of the receiving sub-station at 220 kV connecting machines of the project activity and other project developers. **Refer Appendix 1 for schematic of the flow diagram.**

Energy Export by the project activity at 33 kV metering point is as follows:

$$EG_{\text{export}} = X_1 + X_2$$

Where, X_1 & X_2 is the export reading recording at 33kV metering points for project activity.

$$\text{Transmission Loss in Export (T}_E\text{)} = \text{Transmission Loss (Z) * Energy Export at 33kV metering point (EG}_{\text{export}}\text{)}$$

**Empirical Formula for Energy Export after adjustment of transmission loss (Equation 1)**

Net Energy Export after adjustment of transmission loss = **EG_{export} – Transmission Loss (TE)**

The transmission loss in export is generally less than 5%. However in case of Energy Import, the state utility conservatively applies adjustment of 15% to the import values noted at 33 kV metering point.

Transmission Loss in Import (**TI**) = 15% * Energy Import at 33kV metering point (EG_{import})

Empirical Formula for Energy Import after adjustment of transmission loss (Equation 2)

Net Energy Import after adjustment of transmission loss = **EG_{import} + 15% * EG_{import}**
= **115% * EG_{import}**

Therefore Energy Supplied to Grid after adjustment of transmission loss is difference of equation 1 and 2 as given in the JMR (Form B) signed jointly by Enercon and the state utility.

$$\mathbf{EG_y = EG_{export} - 115\% * EG_{import} - Transmission Loss (TE)}$$

The Joint meter reading noted at 33 KV metering location contains the following data:-

1. Electricity Export (EG_{export})
2. Electricity Import (EG_{import})
3. Transmission Loss (TE) between 33 kV metering point and 220 kV metering point at Enercon substation
4. Net Electricity supplied to the Grid [EG_{export} - 115% * EG_{import} - TE]

JMR is signed by the representatives of Enercon and the state utility. The meter readings (both export and import), transmission loss and net electricity supplied to the grid are recorded in the JMR (33 KV metering point). Hence all these values will be reproduced from the JMR for calculation of emission reductions.

In addition to the JMR (Form B) at 33kV metering location for the project activity, the following documents will also be provided to the DoE for verification:

1. JMR (Form B) at 220kV metering point (bulk meters: main and check) at Enercon substation
2. Transmission loss calculation endorsed / confirmed jointly by the representatives of Enercon and the state utility.



The net electricity supplied to the grid can be cross checked from the invoices raised on the state utility for supply of net electricity supplied to the grid.

The Project is operated and managed by Enercon (India) Ltd. The operational and management structure implemented by Enercon is as follows:

<u>STRUCTURE</u>	<u>RESPONSIBILITY</u>
Managing Director Enercon India Ltd	
CDM Team co-ordinator	→ Review, Corrective action
Corporate CDM Team	→ Review, internal audit
Regional Service Heads	→ Check, authorize & forward Monitoring data
O&M Team	→ Monitor, record, report and archive data

B.8 Date of completion of the application of the baseline study and monitoring methodology and the name of the responsible person(s)/entity(ies)

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Date of completion: 06/03/2007

Name of responsible person/entity: PricewaterhouseCoopers Private Limited (not a Project Participant)

SECTION C. Duration of the project activity / crediting period.

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

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10/03/2006 being the date of placement of purchase order for the wind energy generators.

C.1.2. Expected operational lifetime of the project activity:

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20 years

**C.2 Choice of the crediting period and related information:****C.2.1. Renewable crediting period****C.2.1.1. Starting date of the first crediting period:**

>>

C.2.1.2. Length of the first crediting period:

>>

C.2.2. Fixed crediting period:**C.2.2.1. Starting date:**

>>

15/10/2007, being the date on which the Project is expected to be Registered.

C.2.2.2. Length:

>>

10 years

SECTION D. Environmental impacts

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D.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:

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Enercon appointed Aditya Environmental Services Private Limited to conduct Rapid Environmental Impact Assessment study to assess the impact of the project on the local environment.

Environmental Impact Assessment (EIA) of this project is not an essential regulatory requirement, as it is not covered under the categories as described in EIA Notification of 1994 or the Amended Notification of 2006. However, Enercon conducted the EIA to study impacts on the environment resulting from the project activity.

The EIA study included identification, prediction and evaluation of potential impacts of the CDM activities on air, water, noise, land, biological and socio-economic environment within the study area. The ambient air concentrations of Suspended Particulate Matter, respirable Particulate Matter, Oxides of Nitrogen, Sulphur dioxide and Carbon Monoxide were monitored and were found under limits as specified by CPCB. The noise levels were observed through out the study period and were found to be in the permissible range. Water quality monitoring studies were carried out for determination of physiochemical characteristics of bore wells. The ph level of water was found to be under the specified limits.

The study area represents part of Chitradurga and Tumkur district. The terrain comprises hilly areas, which are sparingly populated, the hills are generally covered with shrubs and grass, and



trees are not found on the hilltops. Moreover the project area doesn't fall under any protected land for wildlife and it has no adverse ecological impacts on the surroundings, flora and fauna found in the vicinity of the project area. The wind-farms do not affect the path of migratory birds.

D.2. If environmental impacts are considered significant by the project participants or the host Party, please provide conclusions and all references to support documentation of an environmental impact assessment undertaken in accordance with the procedures as required by the host Party:

>>

EIA demonstrated that there is no major impact on the environment due to the installation and operation of the windmills. The local ecology is not likely to get impacted by this type of project activity. The local population confirmed that there is no noise or dust nuisance due to windmills. The EIA also ruled out any adverse impacts due to the project activity.

SECTION E. Stakeholders' comments

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E.1. Brief description how comments by local stakeholders have been invited and compiled:

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The comments from local stakeholders were invited through two local stakeholder meetings both conducted on 2 September 2006 at Arashinagundi Village, Hiriur in Chitradurga District and Bukkapatna Village, Sira Taluk in Tumkur District. The two locations are approximately 30 kms apart and the stakeholder consultations were done on the same day. Two advertisements in a local newspaper were placed in Vijaya Karnataka on 19 August 2006 inviting the local stakeholders for the meetings.

The local stakeholder consultation meeting had representatives from the nearby villages, representatives of Enercon and representative of Aditya Environmental Services (consultant to Enercon). The minutes of the meeting are set out in Appendix 1.

E.2. Summary of the comments received:

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The queries/comments from local villagers in Chitradurga district included:

- Comment that there is a significant impact on the economic and social life in and around Chitradurga villages due to the wind power projects. Further, there are no rainfall shortages due to wind mills.
- Query on afforestation work carried out by Enercon
- Query on impact on ground water
- Query on generation capacity of wind mills
- Query on scope of purchasing wind mills by the public
- Query on revenue land being used wherever electrical overhead lines pass

The local villagers responded to the questions queries made by Enercon in Chitradurga district included:

- No noise pollution as the projects are located in hilltops and away from villages



- No water draining, soil erosion due to wind mills
- No problem with cattle grazing in the hills
- Better food production due to better quality of electricity and less load shedding
- No deforestation except while road formation and installation of machines
- No damage or accidents during construction or erection

The queries/comments from local villagers in Tumkur district included:

- A village leader (Mr Santosh) demanded some basic facilities to nearby villages. Another (Mr. Virupaksha) commented that there is no loss of forestry but instead, theft of wood has decreased due to project activity.
- Query on wind mill affecting cloud formation thereby causing drought.

The local villagers responded to the questions queries made by Enercon in Tumkur district included:

- No noise pollution so far. Once project is operational, they would come to know but they believe there would be no noise pollution.
- There is little damage due to water inflow and proper check dam is to be constructed.
- There are no minerals found in the hill areas and therefore no loss of minerals due to the wind projects.
- No problem in animal grazing. The road due to project construction activity helps farmers graze animals easily
- Believe that better food production due to better quality of electricity and less load shedding but will come to know only after commissioning of project
- No deforestation has taken place due to wind mills

E.3. Report on how due account was taken of any comments received:

>>

Enercon provided the following responses in relation to the comments received from the local stakeholders:

In Chitradurga district

- Enercon is carrying out afforestation work in all the hills where the wind turbines are installed.
- There is no impact on ground water due to wind mills.
- Generation capacity of wind mills is 800 kW.
- It is possible to purchase wind mills. In Maharashtra, farmers association has purchased one wind machine.
- Revenue land is not being used wherever electrical overhead lines pass. Access to the land is required only for line inspection in case of a fault.

In Tumkur district

- Enercon will ensure that check dams are constructed as required and no water/soil would enter the fields

**Annex 1****CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY**

Organization:	Enercon (India) Limited
Street/P.O.Box:	A-9, Veera Industrial Estate, Veera Desai Road, Andheri (West)
Building:	Enercon Towers
City:	Mumbai
State/Region:	Maharashtra
Postfix/ZIP:	400 053
Country:	India
Telephone:	+91-22-66924848
FAX:	+91-22-66921175
E-Mail:	yogesh.mehra@enerconindia.net
URL:	
Represented by:	
Title:	Managing Director
Salutation:	Mr.
Last Name:	Mehra
Middle Name:	
First Name:	Yogesh
Department:	Corporate
Mobile:	
Direct FAX:	+91-22-66921175
Direct tel:	+91-22-66924848
Personal E-Mail:	yogesh.mehra@enerconindia.net

Organization:	Coöperatieve Centrale Raiffeisen-Boerenleenbank B.A. (trading as Rabo Bank International)
Street/P.O.Box:	One Queenhithe, Thames Court, EC4V3RL
Building:	
City:	London,
State/Region:	
Postfix/ZIP:	
Country:	United Kingdom of Great Britain and Northern Ireland
Telephone:	+4476649716
FAX:	+4478093552
E-Mail:	
URL:	
Represented by:	
Title:	
Salutation:	Mr.
Last Name:	Carratu
Middle Name:	
First Name:	Domenic
Department:	



CDM – Executive Board

page 32

Mobile:	
Direct FAX:	
Direct tel:	
Personal E-Mail:	Domenic.Carratu@Rabobank.com



Annex 2

INFORMATION REGARDING PUBLIC FUNDING

The Project activity does not involve any ODA financing.

**Annex 3****BASELINE INFORMATION**

The Operating Margin data for the most recent three years and the Build Margin data for the Southern Region Electricity Grid as published in the CEA database are as follows:

Simple Operating Margin

	tCO ₂ e/GWh
Simple Operating Margin - 2002-03	997.02
Simple Operating Margin - 2003-04	1,009.37
Simple Operating Margin - 2004-05	1,003.76
Average Operating Margin of last three years	1,003.38

Build Margin

	tCO ₂ e/GWh
Build Margin- 2004-05	717.99

Combined Margin calculations

	Weights	tCO ₂ e/GWh
Operating Margin	0.75	1003.38
Build Margin	0.25	717.99
Combined Margin		932.04

Detailed information on calculation of Operating Margin Emission Factor and Build Margin Emission Factor is available at www.cea.nic.in.



Annex 4

MONITORING INFORMATION

- **Metering:** Net electricity supplied to the grid is metered jointly by state utility and Enercon through two sets of main and check meters at 33 kV metering point connecting exclusively the machines of project activity after adjusting for transmission loss.

In addition to this there is one set of main and check meter (Bulk meter) at 220 KV metering point at Enercon substation covering machines of the project activity and machines of other project developers. The schematic diagram indicating location of meters at 33 kV and 220 kV metering points for the project activity is attached as Appendix 1.

- **Metering Equipment:** Metering system for the project activity consists of two sets of main and checks meters at 33kV metering point and one set of main and check meters at 220 kV metering point. All the meters are **two-way Trivector meters capable of recording import and export of electricity**. The meters installed are capable of recording and storing half hourly readings of all electrical parameters for a minimum period of 35 days with digital output.
- **Meter Readings:** The electricity supplied to the grid is recorded by taking two JMRs at 56.8 MW and 12 MW at 33kV metering point in the presence of representatives of state utility and Enercon. The JMRs at 33kV metering point contains the value of energy exported, energy imported, transmission loss and net electricity supplied to the grid during the recording period. This JMR is certified by the Executive Engineer of the state utility and Enercon. These certified readings are then used to prepare the invoices to be raised on Discom. Thus the net electricity supplied to the grid as mentioned in the JMR can be crosschecked with the value mentioned in the invoices.
- **Inspection of Energy Meters:** All main and check energy meters and all associated instruments, transformers installed at the Project are of 0.2% accuracy class. Each meter is jointly inspected and sealed on behalf of the Parties and is not to be interfered with by either Party except in the presence of the other Party or its authorized representatives.

Meter Test Checking: All main and check meters are tested for accuracy with reference to a portable standard meter. The portable standard meter is owned by state utility. The main and check meters shall be deemed to be working satisfactorily if the errors are within specifications for meters of 0.2 accuracy class. The consumption registered by the main meters alone will hold good for the purpose of metering electricity supplied to the grid as long as the error in the main meters is within the permissible limits. All main & check meters connected at metering points with RR. No. KBCWP 01 (220kV metering point), KBCWP 02 (33kV metering point) & KBCWP03 (33kV metering point) (please refer project layout Appendix 1) will be tested / calibrated for accuracy annually by either of KPTCL or BESCOM based on the availability of EB officials. KPTCL is a transmission utility and BESCOM is distribution licensee in the state of Karnataka.

If during the meter test checking,

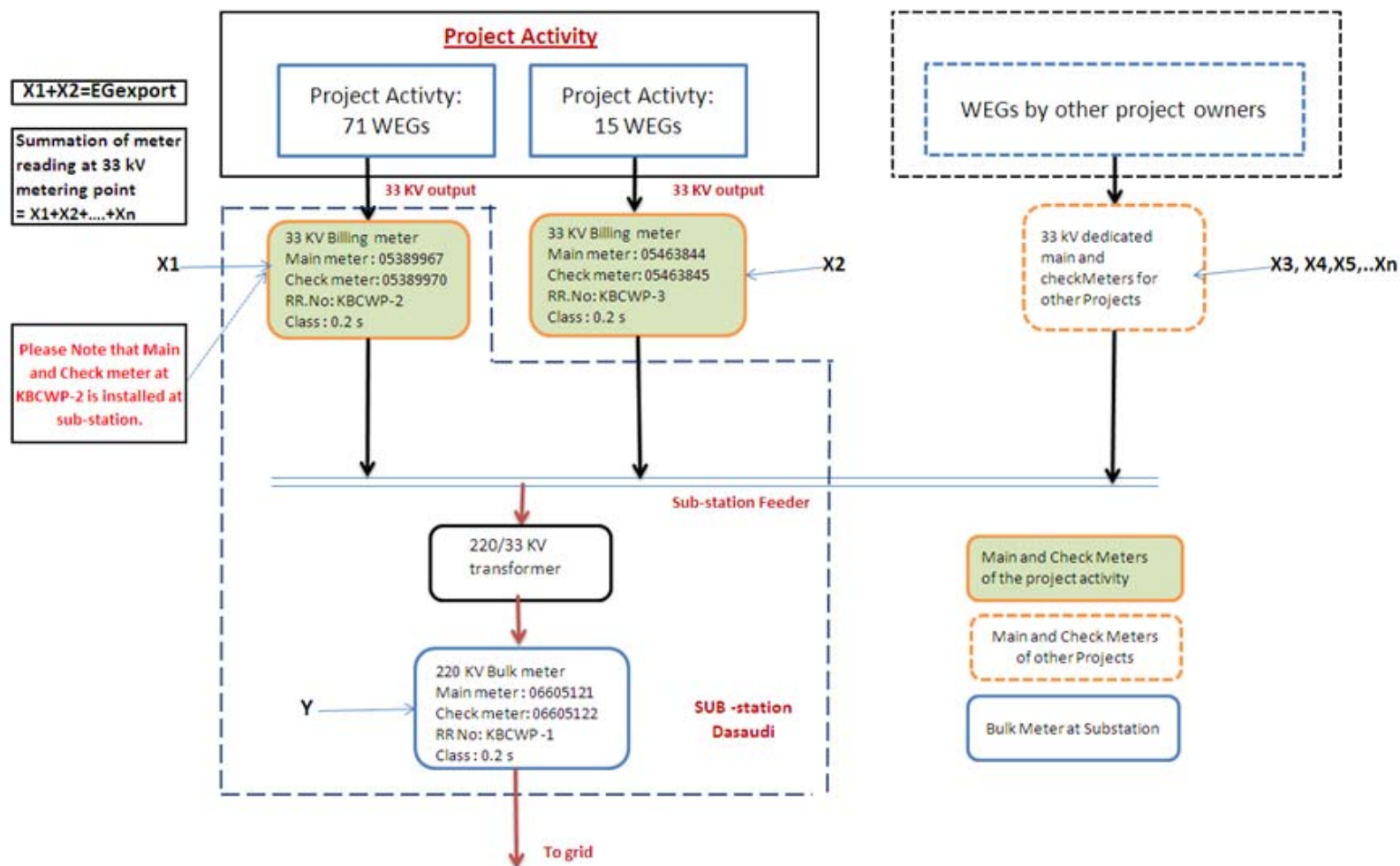


- The main meter is found to be within the permissible limit of error and the corresponding check meter is beyond the permissible limits, then the meter reading will be as per the main meter as usual. The check meter shall, however, be calibrated immediately.
- The main meter is found to be beyond permissible limits of error, but the corresponding check meter is found to be within permissible of error, then the meter reading for the month up to the date and time of such test shall be as per the check meter. There will be a revision in the meter reading for the period from the previous calibration test up to the current test based on the readings of the check meter. The main meter shall be calibrated immediately and meter reading for the period thereafter till the next monthly meter reading shall be as per the calibrated main meter.
- Both the main meters and the corresponding check meters are found to be beyond the permissible limits of error, both the main meters shall be immediately calibrated and the correction applied to the reading registered by the main meter to arrive the correct reading of energy supplied for metering electricity supplied to the grid for the period from the last month's meter reading up to the current test. Meter reading for the period thereafter till the next monthly reading shall be as per the calibrated main meter.

The schematic showing the location of meters for the project activity is given as follows:



Schematic for location of meters at 33kV metering points and the bulk meter at 220 kV at Enercon sub-station.





Annex 5

Bank Letter



26 August 2008

M/s Enercon Wind Farms (Hindustan) Pvt Ltd
Kolsite House, Plot No.31,
Shah Industrial Estate
Veera Desai Road, Andheri (W)
Mumbai 400 053

Dear Sir,

The following key financial parameters were used for project appraisal and approval of your 68.8 MW wind power project in Karnataka and 60 MW wind power project in Rajasthan through Enercon Wind Farms (Hindustan) Pvt Ltd.

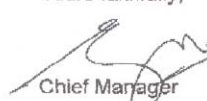
- (a) Internal rate of return for project cash flows : above 12%
- (b) Equity Returns : above 15%
- (c) Average Debt Service Coverage Ratio : above 1.5


We would also like to inform that we considered your case favourably considering that the project is likely to generate additional revenues from CDM. This was important since without CDM revenues your project was not meeting our financing criteria. We now note with concern that the CDM registration of your project is yet to be completed.

It is essential for us to know the exact status of the CDM registration of your project as the same is already delayed and hence your immediate feedback is required.

Thanking you,

Yours faithfully,


Chief Manager





Annex 6
Letter from Rabo Bank

Rabo India Finance

A 100% subsidiary of Rabobank International



Rabo

Rabo India Finance Limited

*Office address GF / A-03 B, Ground Floor
Building No. 9, Tower A
DLF Cyber City, Phase III
Gurgaon 122 002, India*

Telephone +91-124-271 3000

Fax +91-124-271 3005

To

Mr. C Kumaraswamy
Manager-South Asia
Climate Change Services
Det Norske Veritas AS
Bangalore, India

Dear Mr. Kumaraswamy,

As a lender that frequently finances renewable energy projects in India, especially wind farms, we are able to certify that we, and, to the best of our knowledge, other lenders, do not consider that just because a project's Project IRR and / or Equity IRR is higher than interest rate, that it an adequate ground in itself to lend to a project, whether in renewable energy or other sectors. The reason for this is that lenders need an adequate buffer to provide a cushion for adverse developments (for example lower than expected power output). Further, a project IRR just marginally above interest rate neither provides an adequate DSCR (Debt Service Cover Ratio), nor any ability to prevent a loan going into default should interest rates rise, as in fact has happened in India from 2005 / 2006 to the present time, or project performance slip.

In our assessment therefore, not only does project IRR have to be higher than interest rate, but sufficiently higher to provide us with necessary cushion.

We hope this clarifies the matter.

Sincerely,


Jotdeep Singh
Director & Head - India & Regional Co-ordinator - Asia
Renewable Energy & Carbon Credits
Rabobank India Pvt. Ltd.
100% subsidiary of Rabobank

Oct 1, 2008



Annex 7 – WACC Calculation

Weighted Average Cost of Capital:

$$\text{WACC} = [D / (D+E)] * [\text{Cost of Debt}] + [E / (D+E)] * [\text{Cost of Equity}]$$

Cost of Debt:

Cost of debt is defined as the rate at which lenders agree to lend money to a project. The additionality tool and the guidance to investment analysis clarify that for projects that benchmark for project with more than one potential developer should not be based on project specific parameters but should represent the standard in the market. Accordingly, the bank prime lending prevailing at the time of project start date has been considered as the cost of debt. The prime lending rate at the time of investment was in the range of 10.25% - 10.75% [Source: Reserve Bank of India, <http://www.rbi.org.in/scripts/WSSView.aspx?Id=9359>], the average PLR of 10.50% has been considered.

Interest costs are tax deductible, therefore in order to arrive at the post tax cost of debt, the cost of debt is multiplied with marginal tax rate. The loan tenure of the project is 10 years, it may be noted that for the first 10 years, all power projects in India are required to pay tax @ 11.33% (as per section 80 IA of Income Tax Act). Accordingly the marginal tax rate has been considered as 11.33%

The post tax cost of debt therefore works out to: $10.50\% * (1 - 11.33\%) = 9.31\%$

Calculation of Cost of Equity:

The expected return on equity has been determined using the Capital Asset Pricing Model (CAPM)¹. The CAPM economic model is used worldwide to determine the required/expected return on equity based on potential risk of an investment. The CAPM framework is the Nobel award winning work of financial economist Dr. William Sharpe.

$$K_e = R_f + B \times (R_m - R_f)$$

where:

K_e = Rate of return on equity capital;

R_f = Risk-free rate of return;

B = Beta;

$R_m - R_f$ = Market risk premium;

Risk free rate:

The risk free rate is understood as the rate of return on an asset that is theoretically free of any risks, therefore the rate of interest on government bonds are considered as risk free rates. Page 191 of text

¹ The Capital Asset Pricing Model (CAPM) was published in 1964 by William Sharpe, for his work on CAPM Sharpe received the Nobel Prize in 1990. <http://www.investopedia.com/articles/06/CAPM.asp>



book on “Corporate Finance Theory and Practice” by Dr. Aswath Damodaran² of Stern School of Business, New York University (attached as Appendix 5) describes that the long term government bond rates are suitable indicators of risk free rates when the time horizon for the investment is long term.

Accordingly the risk free rate has been taken from long dated Indian government bond rates at the project start date (which is March 2006) which has been considered as it was in the year of investment (i.e in that year, the company had the alternative of this long term risk free investment). The data on government bond rates is published by Reserve Bank of India. (Web-link: <http://rbidocs.rbi.org.in/rdocs/Publications/PDFs/80303.pdf>)

The applicable risk free rate is 7.34%.

Risk Premium:

The most common approach for estimating the risk premium is to base it on historical data, in the CAPM, the premium is estimated by looking at the difference between average return on stocks and average return on government securities over an extended period of history [page 190, Corporate Finance Theory and Practice, Dr. Aswath Damodaran. Attached as appendix 6]. It is preferred to use long term premiums, i.e over a period of 25 years, since considering shorter time periods can lead to large standard errors because volatility in stock returns [page 191, Corporate Finance Theory and Practice, Dr. Aswath Damodaran. Attached as appendix 7]. It is also preferred to calculate the risk premium based on geometric mean of the returns since arithmetic mean overstates the risk premium. Geometric mean is defined as the compounded annual return over the same period [page 191, Corporate Finance Theory and Practice, Dr. Aswath Damodaran. Attached as appendix 7].

Therefore the risk premium has been calculated as the difference in compounded annual return between the BSE-Sensex and the Government bond rates since the year of inception of BSE Sensex, i.e. 1979 – 80. The detailed calculations are presented in the attached excel sheet.

Source: BSE Stock Exchange (www.bseindia.com)

The applicable risk premium is 8.52%.

Beta:

Beta (B) indicates the sensitivity of the company to market risk factors. For companies that are not publicly listed, the beta is determined by referring beta values of publicly listed companies that are engaged in similar types of business. The project activity type is wind power generation; the approach therefore should be to base the beta for the project on the beta values of listed wind power generation companies in India. However, there was only one wind energy or renewable energy power generation company (BF Utility) listed on any stock exchange in India (both BSE- Bombay

² Dr. Damodaran is one of the foremost authorities in the world in the field of Investment Analysis



Stock Exchange and NSE-National Stock Exchange) in year 2005³. Therefore, in the absence of adequate data on companies which are exclusively into the exactly same type of business (i.e wind power projects), the next best option for assessing the risk of these projects is to consider the data available on companies which are involved in similar businesses.

Therefore, we have considered beta values of all electricity generating companies in India. The group of companies considered includes renewable as well as conventional power generating companies. Investors demand a higher return from renewable energy projects than from conventional energy ones, given the higher risks in renewable, including risks of technology, risks from significantly varying and unpredictable resource availability (e.g. wind), and a lower established support base for such projects relative to that for conventional power (e.g. grid connections, bank finance, suppliers, etc.). The use of this Beta value is therefore considered conservative, as it does not add for the higher risk of non conventional energy.

The applicable Beta value has been determined on the basis of the Beta values of all power generating companies in India which were listed on the stock exchange at the time of this investment. Beta values of individual companies have been sourced from Bloomberg and screenshots are available in appendix 3.

The table below summarises the beta values:

Bloomberg Symbol	Company Name	Beta
RELE IN Equity	RELIANCE ENERGY	0.95
GIP IN Equity	GUJARAT INDS	1.36
TPWR IN Equity	TATA POWER CO	1.35
NLC IN Equity	NEYVELI LIGNITE	1.16
CESC IN Equity	CESC LTD	1.63
BFUT IN Equity	BF Utility	1.56
	Average Beta	1.34

Source: Bloomberg⁴

$$WACC = [D / (D+E)] * [Cost of Debt] + [E / (D+E)] * [Cost of Equity]$$

For calculation of WACC, a debt : equity ratio of 70:30 has been considered, as typical for the project type⁵.

³ This can be verified from the database available at the web-link www.securities.com (This website is owned by a Euromoney Institutional Investor Company and It delivers hard-to-get information on more than 80 emerging markets through its award-winning online Emerging Markets Information Service.)

⁴ The beta value used, are the regression betas calculated by Bloomberg based on periodic stock returns. Bloomberg also provides an adjusted beta value after making the following adjustments:

$$\text{Adjusted Beta} = \text{Regression Beta (denoted as Raw beta)} * (0.67) + 1.00 * (0.33)$$

Bloomberg states that this is a default adjustment on the assumption that in future, over a period of time all betas may tend towards the average beta i.e. one. The approach outlined in corporate finance states: the conventional approach to estimate the beta of an investment is a regression of return on investment against returns on a market index (please see attached page no. 196 from “Corporate Finance Theory and Practice by Aswath Damodaran as Annexure 8). Accordingly, the regression beta (and not the adjusted beta) value has been considered.



$$WACC = 70\% * 10.5\% (1-11.33\%) + 30\% * (7.34\% + 1.34 * 8.52\%)$$

$$\text{Therefore, } WACC = 70\% * 9.31\% + 30\% * 18.7\% = \mathbf{12.13\%}$$

As explained under section B.5, sub-step 2(b), the actual cost of debt for the project is 8.5%, if the actual cost of debt is considered, the WACC works out to:

$$WACC = 70\% * 8.5\% (1-11.33\%) + 30\% * (7.34\% + 1.34 * 8.52\%) = \mathbf{10.9\%}$$

⁵ Several regulations and orders refer this as the normative debt equity ratio for wind power projects.

**Annex 8****Clarifications provided for corrections requested question (Submitted on 30th January 2008)**

KERC set a single electricity generation tariff that is applicable to all the wind power generation projects (including the Project Activity) in the Tariff Order dated 18 January 2005. “In the matter of Determination of Tariff in respect of Renewable Sources of Energy”

(source: <http://www.kerc.org/english/index.html>).

Further, this tariff once fixed is applicable for all future wind power generation projects until a new tariff order replaces it.

In determining this tariff, as explained by KERC in the Tariff Order, it employs assumptions on the relevant parameters including capital cost, operating cost, plant load factor (or capacity utilisation factor), financing, taxation, etc. to arrive at the generation tariff that would cover the costs and provide the post-tax equity return. Thus, if a project is set up that has all the parameters exactly similar to those assumed by KERC in its Tariff Order, it will earn the benchmark post-tax equity return. However, if a project has parameters that are different than those assumed by KERC, its equity return will be different than the benchmark post-tax equity return and vice versa.

We provide an illustrative example of how this happens with the key parameter – capital cost per MW. As the tariff is established by KERC on a cost-plus basis, i.e., by relation to the capital cost, this is one of the key drivers of setting the tariff. During the public hearing process, various stakeholders suggested capital costs ranging from Rs. 42.5 million to Rs. 50.0 million and KERC chose Rs. 42.5 million as the reasonable capital cost to determine the tariff for all wind generation projects (refer to KERC Tariff Order).

However, the capital cost per MW of wind turbines in practice is far in excess of Rs. 42.5 million per MW. We provide examples below to show the capital cost per MW in Karnataka projects of different manufacturers and the proposed project activity.

UNFCCC Project ref. No	Title	Make	Cost per MW (Rs Million)
1082	7.85 bundled wind power project in Southern India	Suzlon	49.50
1308	3 MW wind power project at Chikasiddvanahalli, village Chitradurga district, Karnataka	NEG Micon	52.30
1259	Proposed project activity, Enercon Wind Farm (Hindustan) Ltd in Karnataka”	Enercon	47.4

The cost per MW value refers from the respective PDDs of the above-mentioned project uploaded at UNFCCC site.

In other words, if the project has parameters that are similar to the values assumed by KERC and a capital cost of Rs. 42.5 million per MW, using the tariff set by KERC, it would have earned the benchmark rate of return. It so happens that KERC has used extremely conservative assumptions in relation to the tariff parameters including the capital cost (without any provision of reviewing it to align it closer to the market) and therefore, the tariff set by KERC results in the Project Activity achieving equity IRR lower than the benchmark equity return.

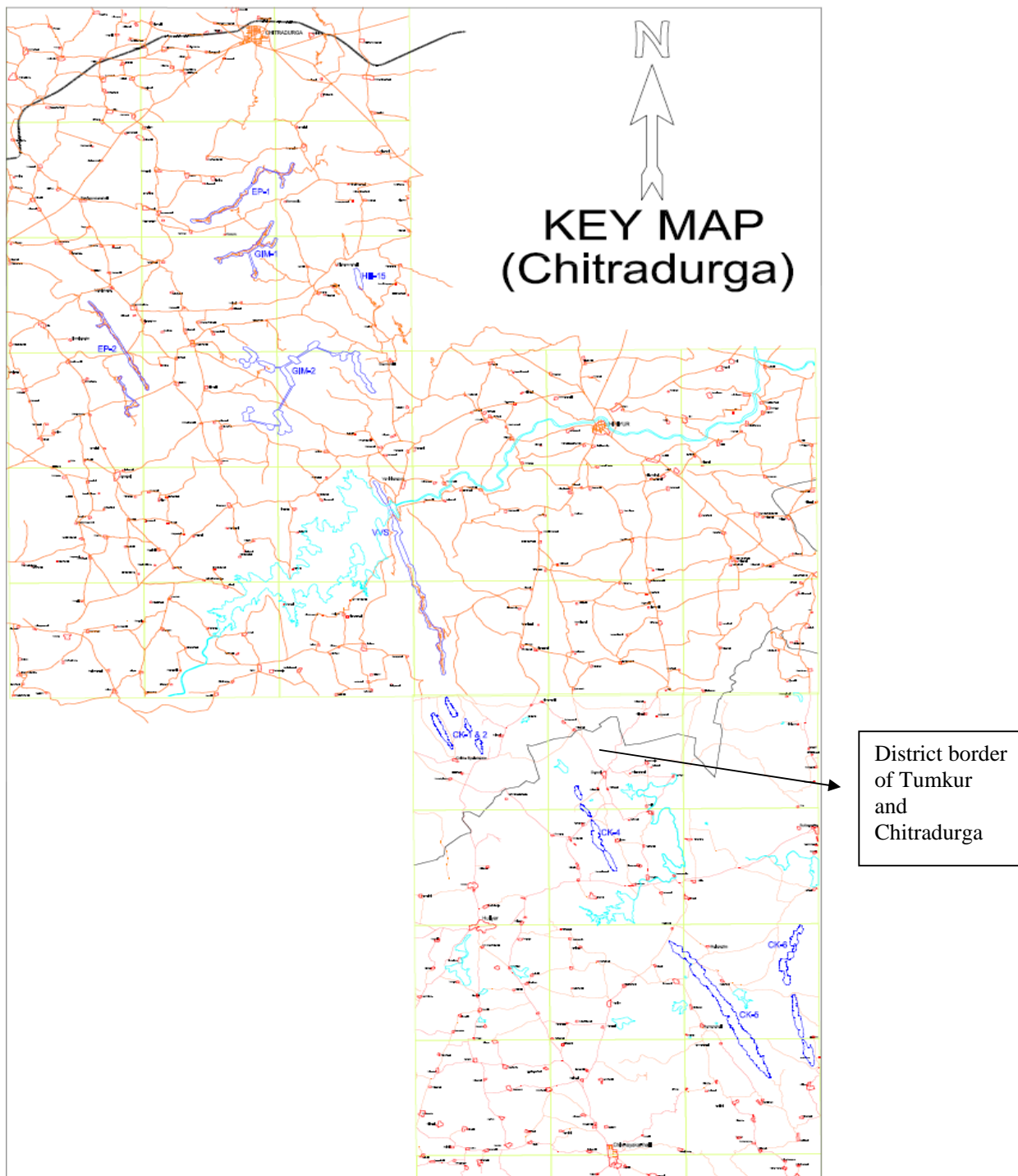
**Annex 9**

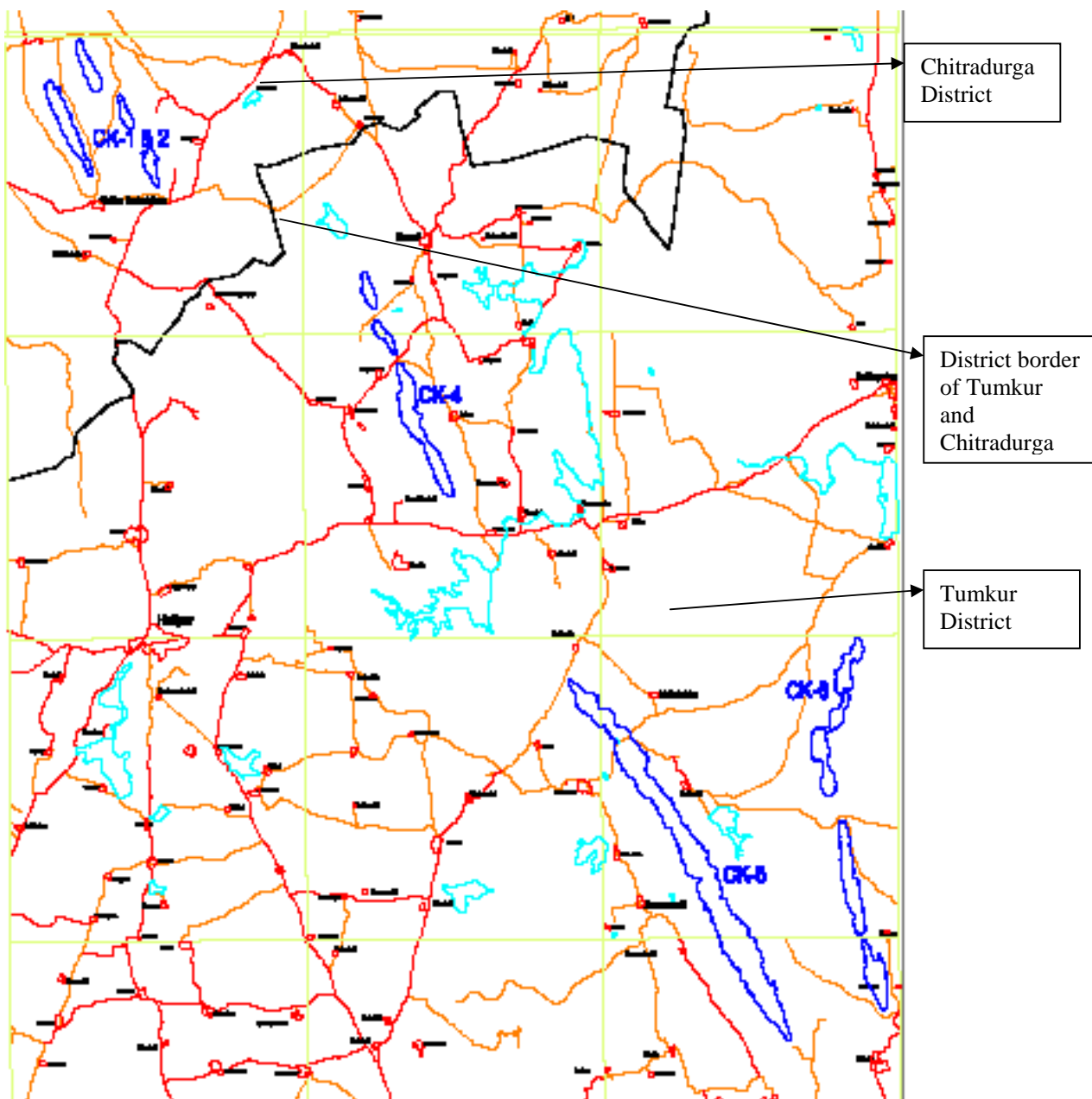
Table of comparison between KERC values and project values (Evidence is mentioned where project assumptions are different from KERC assumptions)

		This Project	KERC tariff guidelines
Capital Cost per MW	Rs. Million	47.4 (evidence: Purchase order, also supported by average industry capital cost per MW at that time)	42.50
PLF	%	26.50%	26.50%
Insurance charges		0.18% (evidence: Insurance documents)	0%
O&M rate	% of project cost	1.25%	1.25%
O&M escalation		5%	5%
Debt %		70%	70%
Equity %		30%	30%
Interest rate		Started at 8.50% (Loan Agreement), now at 9%	11%
Tenure	Years	10.00	10.00
Depreciation rate		7.86% (standard practice)	7%
Interest on Working Capital		12% (conservative)	12.50%
<u>Working Capital</u>			
Receivables	No. of days	45.00 (conservative)	60.00
O&M expenses	No. of days	30.00 (conservative)	60.00
Equity IRR		11.7%	16%



Appendix 1 – Location Map







Appendix 2 – Minutes of stakeholder consultation meeting

Public Consultation Meeting for Wind Farm Projects as Clean Development Mechanism Projects at sites – CK 1&2, Gim Sites and VVS, Chitradurga District, Karnataka State.

Venue: Enercon (India) Limited, CK 1 & 2 Site, Arashinagundi Village, Hiriyr, Chitradurga Dist.

Date: 02nd September 2006, 10 am – 12 pm

Members from the Villages:

1. Sri. Thimmanna
 2. Sri. Kanumappa
 3. Sri. Rajappa
- And 19 participants from the village.

Members from Enercon (India) Ltd., Chitradurga

1. Mr. C.B.Poonacha
2. Mr. Sajith
3. Mr. Fathahulla
4. Mr. Naveen Kumar
5. Mr. Ravidhara

Members from Enercon(India) Ltd., Mumbai

1. Mr. Vivek Sen
2. Mr. Neeraj Gupta

Members from Aditya Environmental Services Pvt. Ltd.

1. **Mr. Gurmeet Singh**

Agenda of the Meeting:

1. Welcome Address and Introduction
2. Project Profile, CDM, Environmental and social issues
3. Description about Wind Energy Conversion.
4. Suggestions and Opinions
5. Queries and Responses from the Stakeholders and Co. Authorities respectively.
6. Vote of Thanks.

1. **Welcome Address:** In the Welcome Address, Mr. C.B.Poonacha has briefed about the purpose of this Public Meeting, how Wind Mills and Wind Energy are occupied major role in generating power thereby rural population is benefited. Further he was pointing out how the benefits of employment opportunities, economical growth taken place in the areas. And also he has quoted examples of various social and religious activities taken up in the villages, for ex. construction of temples, roads through villages etc.

Then Mr. C.B.Poonacha invited Mr. Thimmanna, Village Panchayat leader to preside over the meeting and conducts the further proceedings. And also he has invited village leaders viz. Mr. Kanumappa and Mr. Rajappa on the dias.

**2. Project Profile:**

Mr. Md. Fathahulla: Mr. Md. Fathahulla has described about the Wind Mills and how the Wind Power is generated, why it is called Green Energy and our project is emission free and it is pollution free energy when compared with Thermal power. He reiterated that in Thermal Power, carbon would be emitted into the air, which causes air pollution. He said that the public would not have any bad impact by the Wind Mills. When asked by the villagers about the clouds running away due to running of Wind Mills and thereby causing deficiency in rainfall, Mr. Fathahulla has cleared the doubts of the stakeholders by convincing them about the height of the clouds and the height of the Wind Mill Erector. He said we are conducting afforestation and drainage work to eradicate the soil erosion from the hills. He also informed that the co-operation by the villagers required for successful completion and service of Wind Mills.

Mr. Ravidhara: Mr. Ravidhara has described to the villagers how the power is converted from Wind to Electricity and how the generators are running and generate electricity power. And also he has specified where the generated power will be transmitted and at what rate. He has told about the safety measures taken in our Wind Erectors and automatic stoppage of m/c with more rpm in order to avoid any untoward incidence.

3. President's Address:

- a) Sri. Thimmanna who has presided over the meeting has informed the villagers about how Wind Mills are helped our Villagers and Farmers, benefits to the unemployed one. And we have benefited more from wind mills rather loss of any kind. He also strongly quoted that "The economic and social life has changed due to wind mills in and around Chitradurga Villages. He extended fullest cooperation for development of such activities and also stated that lack of rainfall in the region is not due to Wind Mills. Since last two years we had plenty of rainfall. He also pledged that the cooperation from our villagers is there in future also and sought the same from Enercon.
- b) Sri. Kanumappa has accepted that the temple work is been completed by Enercon only and praised about the social and religious activities by Enercon. Eco friendly project like wind power should come up in all villages which will not harm any environmental balancing, he specified.
- c) Sri. Rajappa, who has told that there was no rainfall shortage due to Wind Mills.

Questionnaire:**a) By the Stakeholders:**

- i) Are you conducting afforestation work in the hills where the plants are removed?
Ans: Yes, We are doing afforestation work in all the hills where M/cs are installed.
- ii) Are there any chances of drying up Ground Water?
Ans: No, Wind Mills do not use any ground water for its process.
- iii) What is the generation capacity of the Machine?
Ans: 800 KW per hour.
- iv) Is there any scope of purchasing machine by the public?



- Ans: Yes, In Maharashtra farmers association has purchased one machine.
- v) There is a rumour that revenue land is used wherever the electrical line passes through? Is it true?
- Ans: No, Only line inspection will be done.

b) By the Company:

- i) Is there any Noise Pollution by running the Wind Mills?
- Ans: So far no idea. But as it is in hilltops and away from villages such nuisance may not happen.
- ii) Is there any water draining, soil erosion due to Wind Mills?
- Ans: No, such incidence not occurred.
- iii) Is there any problem for animals grazing in the hills?
- Ans: No, Cattle are grazing in hill areas as usual.
- iv) How Wind Mills helped in improvement of Crops?
- Ans: By increase in voltage capacity and less load shedding results in increase in food grain production.
- v) Have you observed any deforestation problem?
- Ans: No, Except while forming the roads and installing the machines, there found no deforestation is taken place.
- vi) During construction or erection any damages or accidents occurred?
- Ans: Absolutely not. The Project work is taken up very smoothly and run with more safety standards.

For further queries the representatives from ENERCON put forward to the participants that they could raise any queries within a week and the same can be submitted at ENERCON Office, Bangalore as the address mentioned in the Paper Notification on 19th Aug. 2006.

Vote of Thanks: **Mr. Naveen Kumar** thanked the village leaders and villagers who have set aside their work and shown interest and eagerness to know about the Wind Mills. He also sought cooperation from all the corners for successful operation of windmills thereby achieving the National Target of self-sufficiency in Power Sector.



**Public Consultation Meeting for Wind Farm Projects as Clean Development Mechanism
Projects at site – CK 4 & 6, Tumkur District, Karnataka State.**

Venue: Enercon (India) Limited, CK 4 Site, near Bukkapatna Village, Sira Taluk, Tumkur Dist.

Date: 02nd September 2006, 2 pm – 4 pm

Members from the Villages:

1. Sri. R.H. Veeranna
 2. Sri. Rangaswamy
 3. Sri. Virupaksha
- And 26 participants from the village.

Members from Enercon (India) Ltd., Chitradurga

1. Mr. C.B.Poonacha
2. Mr. Sajith
3. Mr. Fathahulla
4. Mr. Naveen Kumar
5. Mr. Ashok M.G.

Members from Enercon (India) Ltd., Mumbai

1. Mr. Vivek Sen
2. Mr. Neeraj Gupta

Members from Aditya Environmental Services Pvt. Ltd.

1. **Mr. Gurmeet Singh**

Agenda of the Meeting:

1. Welcome Address and Introduction
2. Project Profile, CDM, Environmental and social issues
3. Description about Wind Energy Conversion.
4. Suggestions and Opinions
5. Queries and Responses from the Stakeholders and Co. Authorities respectively.
6. Vote of Thanks.

1. **Welcome Address:** Mr. C.B. Poonacha in the welcome address has explained about the purpose of this Public Meeting, Wind Mills contribution in the generation of electricity in India. He also stated about the rural employment generation due to this wind mills erected in rural areas and how the improvement took place in voltage increase and uninterrupted supply of electricity to the farmers pump sets in the villages. This resulting in improvement of economic status of the society in village areas. He also noted how the contribution by the villagers helped us in establishing the wind farms in their villages and sought cooperation and coordination in the same manner in future to give better service and generate more power.

In spite of above Mr. C.B.Poonacha described about some social work taken up in villages viz. road development, temple construction repairs etc.



2. Project Profile:

Mr. Md. Fathahulla: Mr. Fathahulla explained about the power generating sources available in our country. He made a note that how the Thermal Power is polluting the environment and non-conventional energy sources like wind power is eco friendly and producing green power. What is the difference between the conventional and non-conventional energies, how it contributes to the national requirement etc. were the points made clear to the stakeholders by Mr. Fathahulla.

Mr. Ashok Kumar M.G.: Mr. Ashok Kumar has described how the wind energy will be converted into electrical energy, how it would be transmitted to the Power grids through Sub-stations etc. He also explained about the resources of Wind Mill is wind which is abundant in nature and it is God given gift and is not exhausting. After installation of Wind Mills single-phase problem is almost solved in the villages, he expressed.

3. Address by Village Leaders:

Mr. Rangaswamy: Mr. Rangaswamy remembered that initially there was an awareness problem among the villagers with regard to the Wind Mills. But after understanding the reality, we gave our fullest co-operation for establishing this project. Our cooperation will continue in the same way, he ensured. He also expressed his happiness that such Wind Power energy will enhance the social and economic growth of our village.

Mr. Santosh: Mr. Santosh has demanded some basic facilities to their nearby village.

Mr. Virupaksha : Mr. Virupaksha informed that, due to the Wind Mill project, we have not lost any forestry instead the no. of theft of wood is reduced since the windmill project is going on which is safeguarding forestland.

4. President's Address:

Mr. R.H. Veeranna: Sri . R. H. Veeranna who has presided over the meeting has opined that Wind Mills are building strong base in Power sector. "Wind mills are creating revolution in the generation and supply of electricity. This benefits all the farmers. Even Govt. is helping by implementing such power sectors. Due to the establishment of Wind Mills in large quantity, we found development of villages. Further the wastelands in the hilly terrain, which are not useful for any activities is best, utilized by Wind Farms for generating electricity power. This is a great job. By spending crores of rupees, you are providing electricity to villages, towns and our nation. The company also takes up so many social works. You all have put so many efforts in establishing wind energy sectors, which has given good result. Please continue such type of national development activities" Sri Veeranna explained. He further clears the doubts of villagers that there is no harm and pollution in any manner by running the Wind Mills. Please leave up the rumour about the same, he told.

5. Questionnaire:



a) By the Stakeholders:

- i) There is a rumour that by running wind mill, clouds are running away from the area and thereby causing drought situation.

Ans: No, the rumour is false. The clouds are in very much height and our machines are only 55-60 Meters height. Hence there is no chance of rainy clouds affected by running windmills.

b) By the Company:

- i) Is there any Noise Pollution by running Wind Mills?

Ans: We do not know so far. Once start running the machine we would come to know. But we heard that such noise pollution might not happen.

- ii) Any damages to the farmland due to water flow from the hilltops?

Ans: Little damage is taken place due to water inflow. Proper check dam is to be constructed. Company representatives have promised that the check dams will be constructed and not allowing the water and soil entering into the fields.

- iii) Any type of loss of minerals occurred due to Wind Project?

Ans: No. Such Minerals are not found in the hill areas.

- iv) Is there any problem for animals grazing in the hills?

Ans: No, since the road is there, it is helped the farmers to graze their animals easily.

- v) How Wind mills helped in improvement of Crops?

Ans: After running the machine only we can assess. But definitely there will be an improvement since we get uninterrupted power supply to our pump sets causing increase in food crops.

- vi) Any damages to the Forest by establishing Wind Mills?

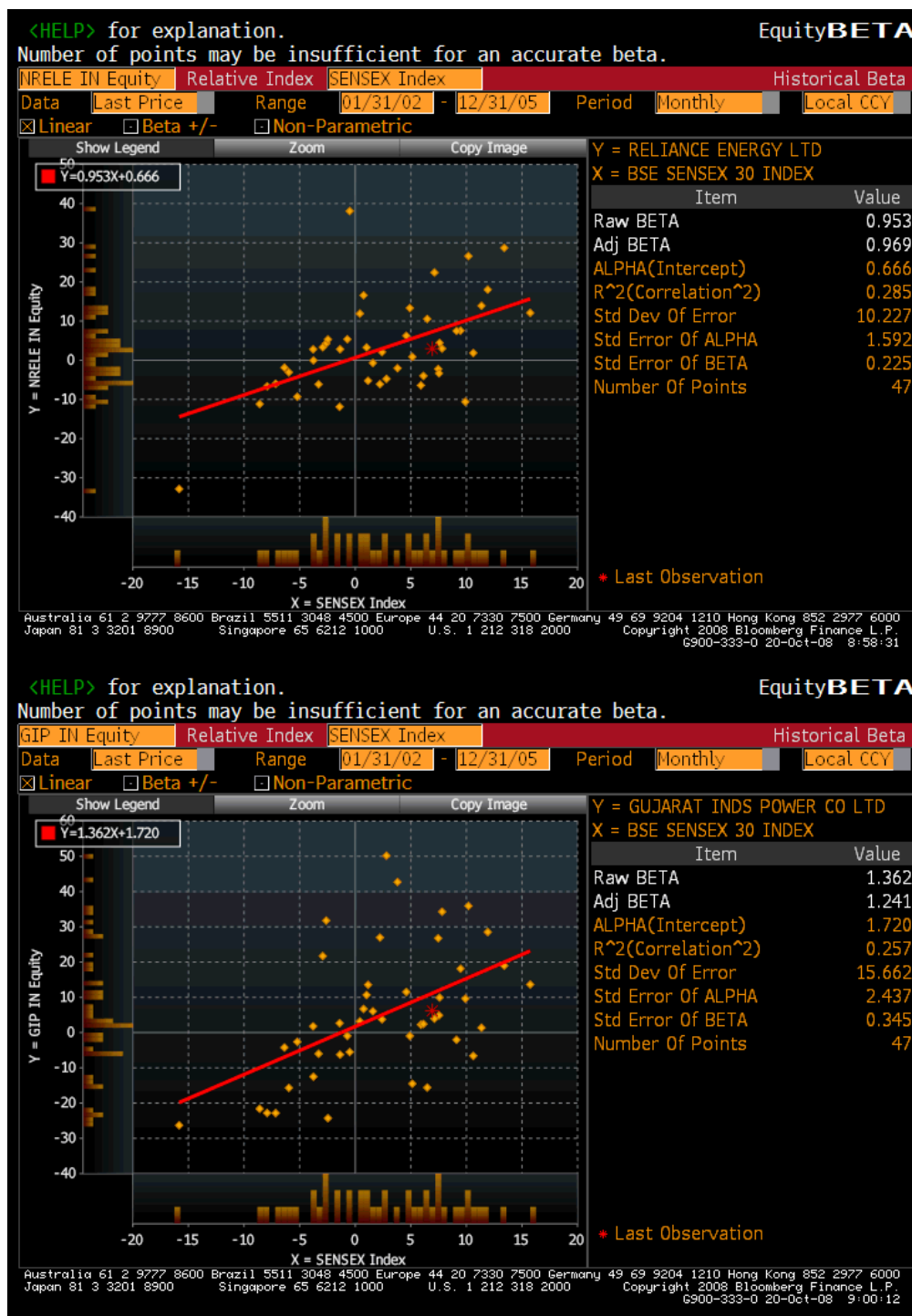
Ans: There is no damage of forestland seen. It is happened only due to fire and not due to erection of Wind Mills.

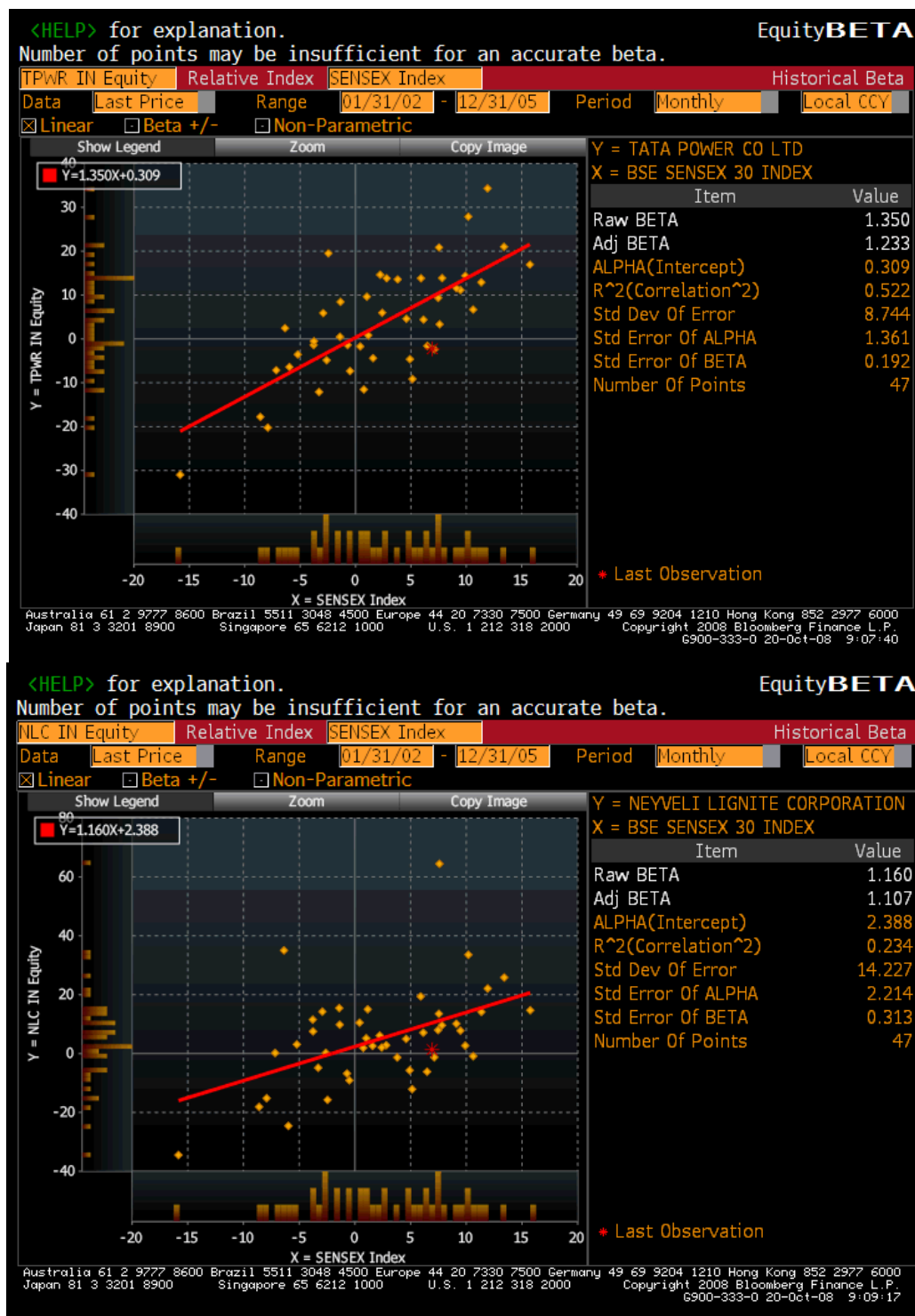
For further queries, the representatives from ENERCON put forward to the participants that they could raise any queries within a week and the same can be submitted at ENERCON Office, Bangalore as the address mentioned in the Paper Notification on 19th Aug. 2006.

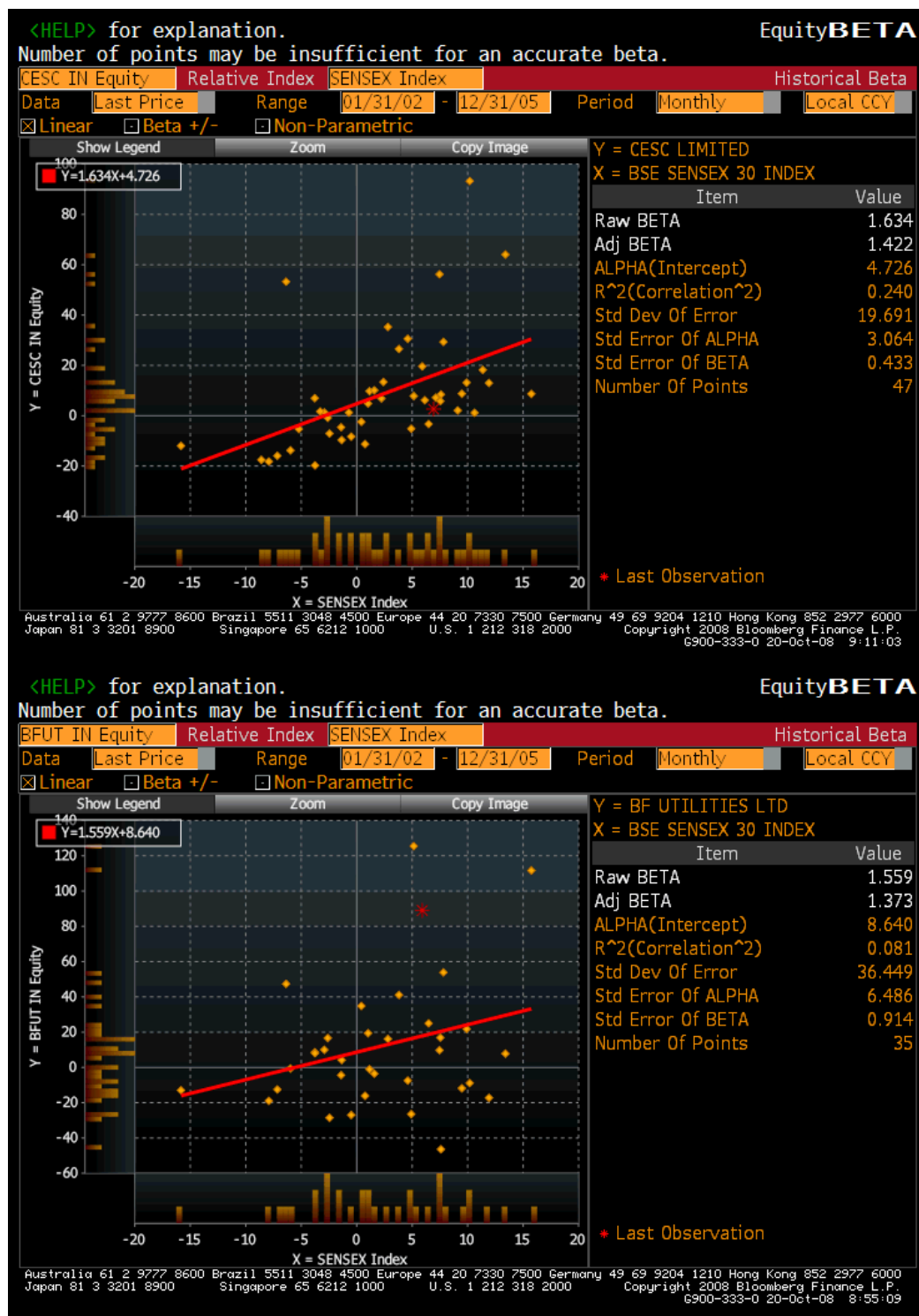
Vote of Thanks: **Mr. Naveen Kumar** offered special thanks to the village leaders and villagers who have set aside their work and shown interest and eagerness to attend the meeting and know about the Wind Mills. He also sought cooperation from all the villagers for successful operation of windmills thereby achieving the National Target of self-sufficiency in Power Sector.



Appendix 3: Bloomberg's Screenshots of Individual Companies for Beta Value









Appendix 4: Page 185 of text book on “Corporate Finance Theory and Practice”

P A R T T W O

Investment Analysis

First Principles of Corporate Finance

Invest in projects that *yield a return greater than the minimum acceptable hurdle rate.*

- The hurdle rate should be *higher for riskier projects* and should reflect the *financing mix* used — either owners' funds (equity) or borrowed money (debt).
- Returns on projects should be measured on the basis of *cash flows* generated and the *timing* of these cash flows; they should also take into account both *positive and negative side effects* of these projects.

↓

Choose a *financing mix* that *maximizes the value of the firm* and matches the *assets* being financed.

↓

If there are not enough investments that earn the hurdle rate, *return the cash* to the owners of the firm. The *form of returns* — dividends and stock buybacks — will depend on the *stockholders' characteristics*.

↓

Objective: Maximize the Value of the Firm.

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Appendix 5: Page 186-187 of text book on “Corporate Finance Theory and Practice”



Estimating Hurdle Rates for Firms

W

HEN ANALYZING firms, we would like to know the cost of raising funds from equity investors (cost of equity), the interest rates they have to pay when they borrow (cost of debt), and their overall cost of financing their operations (cost of capital). Why? Knowing that Boeing's cost of equity is 10.38% and that its cost of capital is 9.17% is a necessary input to value the equity in the firm or the firm itself. In addition, Boeing cannot assess the quality of its existing investments or how much to pay in dividends without knowing how much it costs it to raise funds.

How do we estimate the cost of raising funds from equity investors? In the last chapter, we laid the groundwork for this process. We argued that only that portion of a firm's risk that cannot be diversified away should be considered to be the equity risk in the firm, and that the expected return on an equity investment should reflect this risk. The risk and return models developed in the last chapter provide ways of measuring this risk, and we use these risk measures to come up with expected returns. Although they might vary in the details, these models all require three inputs — a riskless rate, a beta or betas, and a risk premium or premiums. In this chapter, we consider the best ways to estimate these inputs and use them to estimate the expected return on an equity investment. Since investors in equity in a firm require this return to compensate for equity risk, the expected return is also the cost of equity to the firm.

To estimate the cost of debt, we draw on our description of default risk from the last chapter. We consider approaches that can be used to assess the default risk in a firm and how these measures of default risk can be used to compute a cost of debt for the firm.

Because firms use both debt and equity to finance their investments, we examine how much of each the firm uses, yielding an overall cost of financing, that is a weighted average of the costs of equity and debt. This overall cost of financing is the cost of capital to the firm.

The Cost of Equity and Capital

Firms raise money from both equity investors and lenders to fund investments. Both groups of investors make their investments expecting to make a return. In the last chapter, we stated that the expected return for equity investors would include a premium for the equity risk in the investment. We label this expected return the **cost of equity**. Similarly, the expected return that lenders hope to make on their



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investments includes a premium for default risk, and we call that expected return the **cost of debt**. If we consider all of the financing that the firm takes on, the composite cost of financing will be a weighted average of the costs of equity and debt, and this weighted cost is the **cost of capital**.

In this chapter, we use the models that we introduced in the last chapter to estimate the costs of equity and capital for firms. In particular, we look at Boeing, The Home Depot, and InfoSoft and evaluate what it costs them to raise equity, debt, and capital. We begin by estimating the equity risk in each of these firms and using the equity risk to estimate the cost of equity, and we follow up by measuring the default risk to estimate a cost of debt. We conclude the chapter by determining the weights we should attach to each of these costs to arrive at a cost of capital.

Why Do We Need Hurdle Rates for Firms?

Why do firms need to know their costs of equity and capital? One of the fundamental decisions that every business needs to make is to assess where to invest its funds and to reevaluate, at regular intervals, the quality of its existing investments. The investment principle, stated in Chapter 1, specifies that firms should invest in assets only if they expect them to earn more than their hurdle rates. The costs of equity and capital for a firm represent what the firm needs to make *collectively on all its investments* in order for them to be good investments. For instance, if The Home Depot's cost of capital is 9.51%, it has to make at least 9.51% on the capital it has invested in all its existing investments. Alternatively, considering the equity investors' perspective alone, The Home Depot with a cost of equity of 9.78% has to earn at least 9.78% on the equity it has invested in all its existing investments for these to be considered good investments. It is worth emphasizing, however, that this does not imply that every project The Home Depot takes will be measured against these criteria, since projects within a firm can have varying degrees of risk. We consider project-specific costs of equity and capital in the next chapter.

Knowing a firm's cost of equity and capital also allows us to compare different ways of financing its operations. We can change the mix of debt and equity at Boeing, for instance, and examine the effects, if any, on the cost of capital for the firm. Increasing the proportion of debt at the firm may allow us to lower the cost of capital from its existing level of 9.17%, letting the firm accept more investments.

In Chapter 5, we noted that the value of a business is computed by discounting the expected cash flows from the business at the cost of capital. We also measured the value of equity by discounting the expected cash flows to equity investors at the cost of equity. Given that our objective in making decisions is to maximize the value of the business, and by extension, the value of the stock (equity), the costs of equity and capital become fundamental inputs into the decision process.



CT 7.1: As long as firms are growing rapidly, they do not need to know their costs of equity or capital. Is this statement true? Why or why not?

Cost of Equity

The cost of equity is the rate of return investors require on an equity investment in a firm. The risk and return models described in the previous chapter need a riskless rate



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- If no such securities exist in the market in which you are attempting to estimate a real riskless rate, it can be approximated by the long-term real growth rate of the economy. Thus, the real riskless rate in China may be set equal to 6% because that is what you expect the long-term real growth rate in the Chinese economy to be. It will be much lower (2–3%) for more mature, slower growth economies.

Risk Premium

The risk premium is a significant input in all the asset pricing models. In the following section, we begin by examining the fundamental determinants of risk premiums and then look at practical approaches to estimating these premiums.

What Is the Risk Premium Supposed to Measure? The risk premium measures the “extra return” that would be demanded by investors for shifting their money from a riskless investment to an average risk investment. It should be a function of how risk-averse investors are and how risky they perceive stocks (and other risky investments) to be, relative to a riskless investment. Because each investor in a market is likely to have a different assessment of an acceptable premium, the premium will be a weighted average of these individual premiums, where the weights will be based on the wealth the investor brings to the market. Investors with more wealth, like Warren Buffett, will therefore have their risk premiums weighted more than investors with less wealth.

- ✓ **CQ 7.1:** Assume that stocks are the only risky assets and that you are offered two investment options. One is a riskless investment on which you can make 6.7%, and the other is a stock mutual fund. How much more than 6.7% would you need to be offered, on an expected basis, to pick the latter? Would you ever settle for less than 6.7%?

Estimating Risk Premiums We look now at two ways to estimate the risk premium in the capital asset pricing model. One is to look at the past and estimate the premium earned by risky investments (stocks) over riskless investments (government bonds); this is called the **historical premium**. The other is to use the premium extracted by looking at how markets price risky assets today; this is called an **implied premium**.

Historical Risk Premiums. The most common approach to estimating the risk premium is to base it on historical data. In the arbitrage pricing model and multifactor models, the raw data on which the premiums are based are historical data on asset prices over very long time periods. In the CAPM, the premium is estimated by looking at the difference between average returns on stocks and average returns on riskless securities over an extended period of history.

In most cases, we follow these steps to find historical risk premiums. First, we define a time period for the estimation, which can range as far back as 1926 for U.S. data.⁴ Then, we calculate the average returns on stocks and average returns on a riskless security over the period. Finally, we calculate the difference between the returns

⁴ The most widely used database, from Ibbotson Associates, has returns going back to 1926. Jeremy Siegel at Wharton recently presented data going back to the early 1800s.



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on stocks and the riskless return and use it as a risk premium to predict future returns. When we use historical premiums, we implicitly assume that the risk aversion of investors has not changed across time and that the relative riskiness of the risky portfolio (stocks) has not changed over time either.

In calculating the average returns over past periods, a measurement question arises: Should we use arithmetic or geometric averages to compute the risk premium? The arithmetic mean is the average of the annual returns for the period under consideration, whereas the geometric mean is the compounded annual return over the same period. The following example demonstrates the difference.

Year	Price	Return
0	\$50	
1	100	100%
2	60	-40%

The arithmetic average return over the two years is 30%, while the geometric average is only 9.54% ($1.295 - 1 = 1.0954$). Those who use the arithmetic average premium argue that it is much more consistent with the framework⁵ of the CAPM and a better predictor of the risk premium in the next period. The geometric mean is justified on the grounds that it takes into account compounding and that it is a better predictor of the average premium in the long term. There can be substantial differences in risk premiums based on the choices made at this stage, as illustrated in Table 7.1. The data in the table are based on historical data on stock, treasury bill, and treasury bond returns and provide estimates of historical risk premiums. As you can see, the historical premiums can vary widely depending on whether we go back to 1926, 1962, or 1981, whether we use T. Bills or T. Bonds as the riskless rate, and whether we use arithmetic or geometric average premiums.⁶ Although it is impossible to prove one premium right and the others wrong, we are biased toward

- *Longer term premiums*, since stock returns are volatile and shorter time periods can provide premiums with large standard errors. For instance, the premium extracted from 25 years of data will have a standard error⁷ of about 4 to 5%.
- *Long-term bond rates as riskless rates*, since our time horizons in corporate financial analysis tend to be long term, and we use the treasury bond rate as our riskless rate.
- *Geometric average premiums*, since arithmetic average premiums overstate the expected returns over long periods.⁸ The geometric mean yields lower premium

⁵ The CAPM is built on the premise of expected returns being averages and risk being measured with variance. Since the variance is estimated around the arithmetic average, and not the geometric average, it may seem logical to stay with arithmetic averages to estimate risk premiums.

⁶ Booth (1999) examines both nominal and real equity risk premiums from 1871 to 1997. Although the nominal equity returns have changed over time, he concludes that the real equity return has been about 9% over this period. He suggests adding the expected inflation rate to this number to estimate the expected return on equity.

⁷ Assuming that returns in individual years are independent, the standard error of a 25-year estimate can be calculated by dividing the annual standard deviation in stock prices in the United States (about 25%) by the square root of the number of years ($\sqrt{25} = 5$), yielding a standard error of 5% ($25\%/5$) in the estimate.

⁸ When we look at markets like the United States that have survived for 70 years without significant breaks, we are looking at the exception. To provide a contrast, consider the other stock markets in which one could have invested in 1926; many of these markets did not survive, and an investor would have lost much of his or her wealth.



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Betas

The second set of inputs that we need to put risk and return models into practice are the betas for investments. In the CAPM, the beta of an investment is the risk that the investment adds to a market portfolio. In the APM and multifactor model, the betas of the investment relative to each factor have to be measured. Three approaches are available for estimating these parameters. One is to use historical data on market prices for individual investments; the second is to estimate the betas from the fundamental characteristics of the investment; and the third is to use accounting data. We describe all three approaches in this section.

Historical Market Betas The conventional approach to estimating the beta of an investment is a regression of returns on the investment against returns on a market index. For firms that have been publicly traded for a length of time, it is relatively straightforward to estimate returns that an investor would have made by investing in the firm's stock each interval (such as a week or a month) over that period. In theory, these stock returns on the assets should be related to returns on a market portfolio, that is, a portfolio that includes all traded assets, to estimate the betas of the assets. In practice, we tend to use a stock index, such as the S&P 500, as a proxy for the market portfolio, and we estimate betas for stocks against the index.

The standard procedure for estimating betas is to regress stock returns (R_j) against market returns (R_m).

$$R_j = a + bR_m$$

where

a = Intercept from the regression

$$b = \text{Slope of the regression} = \frac{\text{Covariance}(R_j, R_m)}{\sigma_m^2}$$

The slope of the regression corresponds to the beta of the stock and measures the riskiness of the stock.

The intercept of the regression provides a simple measure of performance of the investment during the period of the regression, when returns are measured against the expected returns from the capital asset pricing model. To see why, consider the following rearrangement of the capital asset pricing model:

$$\begin{aligned} R_j &= R_f + \beta(R_m - R_f) \\ &= R_f(1 - \beta) + \beta R_m \end{aligned}$$

Compare this formulation of the return on an investment to the return equation from the regression:

$$R_j = a + bR_m$$

Thus, a comparison of the intercept (a) to $R_f(1 - \beta)$ should provide a measure of the stock's performance, at least relative to the capital asset pricing model.¹⁴ In summary, then:

¹⁴ The regression is sometimes calculated using returns in excess of the riskless rate, for both the stock and the market. In that case, the intercept of the regression should be zero if the actual returns equal the expected returns from the CAPM, greater than zero if the stock does better than expected, and less than zero if it does worse than expected.