Economic and Financial Feasibility of Wind Energy - Case Study of Philippines

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Abstract

The financial viability of a 30 MW wind farm proposed to be set-up in St. Ana in Philippines was examined. It was found that project is viable if established by a company with a low hurdle rate (8.68%) and good reach to avail low cost financing from domestic financial institutions, who may have such packages for low-risk customers. Most of the private sector investors however have higher discount rates due to high financing costs, and higher risk premiums charged by financers. The viability was an issue at risk adjusted discount rate of 13.2%, a typical rate for private sector investors in Philippines. Scenarios for variation in base parameters as well for a variety of financial packages, including revenues from CDM were run. Although CDM revenues improve attractiveness of the project, viability remains an issue. A financing package, that may have a grant component (as with the Danida package in the past), can help project make viable in this case.

1 Introduction

Wind energy has been one of the most promising renewable energy with an installed capacity of 74,223 MW at the end of 2006, spread across 70 countries[1]. Market has been growing at more than 30% despite supply constraints with Euro 18 billion investment in generating equipments in 2006. Although most of the installed capacity is in developed countries, some developing countries such as India and China are also among the high growth markets., indicating viability of wind energy for entrepreneurs in developing countries as well.

There are varying estimates of wind energy potential in Philippines; from 7400 MW[2] to 76600 MW[3]. The Department of Energy, Philippines identified areas with strong winds, which can contribute a capacity of 345 MW, and invited investors to set up wind energy

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1 GWEC, 2007. **Global wind energy markets continue to boom – 2006 another record year**, Global Wind Energy Council. ***http://www.gwec.net/index.php?id=30&no_cache=1&tx_ttnews%5Btt_news%5D=50&tx_ttnews%5BbackPid%5D=4&cHash=7a562a4d4e***

2 Biota Filipina, March 2006, WWF. http://www.wwf.org.ph/downloads/biota/Mar2006.pdf

3 Elliott, D., Schwartz, M, George, R. Haymes, S., Heimiller, D., Scott, G., McCarthy, E. (February 2001). **Wind Energy Resource Atlas of the Philippines,** National Renewable Energy Laboratory, USA. (NREL/TP-500-26129; http://www.nrel.gov/wind/pdfs/26129.pdf).

farms. Subsequently, a 25 MW wind power plant in Luzon, first wind energy plant in Philippines, was commissioned in 2005. Renewable energy projects find it difficult to access to finance, particularly in developing countries and wind energy is not an exception to this. Although Philippine Government provides incentives through Wind Power Investment Kit to promote wind energy, funding from external sources has been key to development of wind energy in Philippines so far. Besides first plant in Luzon, which was funded by Danish Agency for Development Assistance (DANIDA), some other projects are in early stages of discussions for funding by other donors . Financial assistance from the United Nations Development Programme-Global Environment Facility (UNDP-GEF) in project preparation and loan guarantee for the project is one of the options for development of wind energy in Philippines. Domestically, loan guarantees have been given to some wind projects by Philippine Export and Import Bank, and Development Bank of the Philippines also has its own Wind Energy Financing Program. Since wind energy may find it difficult to compete with low grid tariffs, it becomes important to carry out Economic and Financial Analysis to determine the level of support needed through grants and / or soft loans for specific wind energy projects. This paper is an attempt in that direction; it discusses various possible options to make wind energy projects viable in St. Ana, a potential location for wind energy farm in Philippines.

2 Financial Analysis of Sta. Ana Wind Energy Project

2.1 St. Ana- Location and Technical Assessment

Philippines is made up of hundreds of islands with three main island groups Luzon, Visayas, and Mindanao. From the wind resource perspective these islands can be divided in three zones; zone 1 up to maximum air velocities as high as 70 m/s, zone 2 with maximum wind velocities up to 55 m/s, and zone 3 up to 35 m /s. Sta. Ana falls in the first zone and is located in the northern tip of Philippines in the Cagayan region. Philippine is a typhoon prone zone; maximum wind speeds pose a challenge for design of wind turbines and increase their costs. Site selection for turbines was made by Philippines experts using standard criteria and they also carried out wind measurements at the selected site. Technical assessment of the wind farm was carried out by the Wind Energy, Risoe with the help of local experts, and using wind data measurements between September 2005 to April 2006. The technical data from the assessment was used in the analysis. Wind measurements are normally required for longer durations to guard against random short time variations, and to increase reliability. Such measurements can also be verified for reliability using data from other available studies.

Sta. Ana has been proposed as a 30 MW wind energy farm. The results of the technical assessment for Sta. Ana indicated a mean wind speed of 4.9 m /s, and a maximum of 18 m /sec, with mean power at 132 W/m2. According to the technical analysis, generation can be expected to be 60 GWh / year , using 2 MW V66/ 67 m wind turbines. Generation however goes up to 80 GWh /year using 2 MW V80 / 67 m wind turbines[4.] Expected investment for this was indicated at US$30 million in the plant and machinery.

2.2 Financial Analysis

The analysis has been carried out for the proposed 30 MW Wind Farm at St. Ana. Analysis has been carried out only for 80 GWh, since viability was an issue even at 80 GWh.

4.The generation depends on the location of wind turbines at the site, and type of wind turbines, varying from 43- 61 GWh/y for 2 MW V66 /67 m wind turbines to 57-79 GWh / y for 2 MW V80 / 67 m wind turbines.

From the analysis, concessional financing and / or the CDM come out important for project viability, if normally acceptable internal rate of return (IRR) to private investors (at a minimum 13.2%) is considered. Since St. Ana does not seem to be viable without concessional financing, it can be considered a good candidate for the CDM.

Project financial feasibility was assessed by calculating net present value (NPV), and IRR of the project. Impacts of the expected CDM revenues by selling certified emissions reduction credits (CERs) on NPV and IRR of the project were also calculated. Two set of sensitivity analyses were carried out; the first set for variation in project parameters such as expected investment, electricity generation, and O & M costs, and the second set for a set of financial packages that may be available to investors. The project was evaluated for its lifetime of 20 years. All costs and benefits data used in the analysis are based on 2006 prices.

2.21 Data and Assumptions

Data and the assumptions made in the analysis are included Annexure 1. The data was provided by local experts. Some of the data are discussed below.

Total Investment: Estimated total investment for the wind farm was US$51.77 million including for feasibility study, site and project development, plant and equipment, engineering and installation, and other miscellaneous expenses. Investment is made in 2007, but no escalation was considered.

Annual Operation & Maintenance (O & M) Costs: Estimated at US$1.1 million per year (2.1% of investment), these include land lease, property taxes, personnel, insurance, spare parts, equipment repairs, travel, administrative costs, contingencies etc. O & M costs starts occurring only from 2008 (first year of plant operation), but no escalation in the prices is considered until first year of operation (2008). O & M costs are assumed to increase by 3% every year, over the previous year's costs.

Estimated annual energy output: It is assumed that the plant achieves 80 GWh level of generation in the first year of the operation itself, and the level is maintained over the 20 year life of the plant. Transmission losses to point of sale to distribution company are taken at 7%. Therefore power available for sale is 93% of the above generation.

Electricity sales price: Projected rate of power purchase by the distribution utility was taken as Philippine Peso (Php or P) 4.91 per unit (KWh) in 2006. It was taken to increase by 3% every year (over the previous year's price).

Financing Plan: The required investment is planned to be funded through 20% equity contribution, and the rest 80% through a loan. In the base case, loan is assumed to be from domestic sources (such as DBP in Philippines), the term being 15 years, with a (GP) period of six years, and an interest rate of 8%. The loan disbursal is done during the construction period, which is assumed to be one year (first year). Entire loan is assumed to be disbursed in the first year at the end of the year (and hence does not incur any interest costs during the first year). If we were to assume that disbursal of loan is in the beginning of the first year, interest for one more year will need to be paid, which could be paid at the end of the first year. In reality, disbursal may occur in a phased manner, or towards second half of the year, resulting payment of some interest costs in the first year also.

No amortization of the interest and principal payments has been done to arrive at equated installments (quarterly, or half yearly, or yearly). Principal repayments are assumed annual, and divided equally over the term. Principal repayments (and interest payments) are assumed to be made at the end of the year. So interest is paid for the full year on outstanding principal at the beginning of the year.

Revenues from the CDM: The combined margin emission factor was applicable in this case. It was 0.655 t CO_2 eq. / MWh in the case the case of Northwind Power Plant, proposed in Philippine, but has come down slightly since then. It was taken as 0.625 t CO_2 eq. / MWh, as calculated by Mercapto, one of the project partners. CER prices can vary- a range of \$5 to \$20 per ton has been observed in the past. CER prices of \$6 per ton and \$10 per ton were considered for the base case.

Revenues from sale of CERs are assumed to occur for the entire life of the plant. The CDM rules currently permit two terms; 10 year, or 14 year with a requirement to revise baseline after 7 years. This could change the available CERs and hence revenue from the CDM. Price of the CERs may also be different after 7 years. Also, CDM (or a similar mechanism) could continue beyond current time frame, once negotiations on this issue are over at the international forums. Prices of CERs then may go up. For simplicity, no change in baseline and CER prices were considered; instead CERs revenue at these rates were assumed for entire plant life.

2.22 Methodology

As already mentioned, NPV and IRR were used as indicators to determine financial viability.

Net Present Value (NPV): NPVs were calculated at the discount rate (or hurdle rate) corresponding to the cost of the finance and spread needed by typical investors in Philippines (based on information provided by experts). Typical discount rate for the given financial plan of the project in the base case worked out to 8.68%.

Calculations of discount rate consisted of calculation of weighted average cost of capital (wacc) derived from the financing option available to the investors. The data for this was provided by the local experts in Philippines. The wacc[5] was calculated as follows;

$W_C = (E/TC) * R_E + (D/TC) * R_D * (1-T)$

Where; W_C is weighted average cost of capital, E is the equity contribution, D is the debt, TC is the total cost (D+E), R_E is the required return on equity, R_D is required rate of return on debt, and T is the tax rate

The required rate of return on equity was taken as 11%.

Required rate of return on debt was calculated as follows;

R_D = Rate of interest on debt + 1.5% (exchange risk , in case of foreign loans) + 2 % guarantee fee (in case of foreign loans to private sector; it is 1% for loans to government in Philippines, and between 1.5 to 2.5% for others).

The discount rate (or hurdle rate) then is taken as W_C + 2% spread (for real IRR, and 5% for nominal, taken by some investors in Philippines).

Thus, the wacc in the base case (with 20% equity, and 11% R_E , 80% domestic loan at 8% interest rate, and tax rate of 30%) is;

$= 0.20 * 11 + \{(8+0 \text{ (forex risk cost)}+0 \text{ (guarantee cost)}\}*0.80*(1-0.3)\} = 6.68\%$

And discount rate = 6.68+2 = 8.68 %

NPV was also calculated at a discount rate of 13.2%, which was considered risk adjusted discount rate for their wind energy projects in Philippines by Northwind, which was registered as a CDM project. According to available information, most of the private investors may require an IRR of 17-18% (in nominal terms) for the project to be considered viable.

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5 wacc does not remain constant throughout the project life. As the debt is repaid, contribution of debt to wacc will reduce and that of equity increase. Therefore, considering that cost of equity is more than debt, wacc will increase over period of time. But it is very difficult to calculate a weighted wacc from year-wise wacc. To increase the accuracy of the NPV calculations, what is done is that these wacc values are used to discount corresponding cash flows in the respective years to calculate the NPV. This has not been done here due to complications involved. Therefore, NPV values obtained can said to be somewhat overestimates.

Internal Rate of Return: Following types of IRRs were calculated;

(a) **Financial IRR for the project entity**, based on operation-oriented cash flows of the project.

(b) **Modified financial IRR for the project**. IRR assumes re-investment of cash flows, as well as re-finance (in case of intermediate negative cash-flows) at the same rate as IRR. Re-investment and re-finance rates for the intermediate cash flows can be provided in the modified FIRR. These were taken as 6% for reinvestment, and 10.5% for re-finance (same as short term loan for working capital in Philippines).

(c) **Financial IRR for the investor** based on cash flows of the investor. It only considers cash flows of the investor. This could be interest to the shareholders, who invest in the project.

Impact of carbon financing: Base case was extended to include impact of carbon financing (as a CDM project) on the above indicators (NPV and IRRs). Two CER prices; $6 and $10 per ton/ CO_2 eq. were considered.

2.23 Base case variations

Following variations of the base case were considered, after discussions with the Philippine partners, reflecting their perception on uncertainty in the data;

(a) Electricity sales price is 10% higher

(b) Investment in the wind farm is 20% higher

(c) Electricity generation from the plant is 20% lower

(d) Annual O & M costs are 20% higher

2.2.4 Financing Scenarios

This included analysis of a variety of possible financing options,. Discount rates were calculated from these options and a spread-sheet model simulated to find impact of the options on various indicators. The financing scenarios are indicated in Table 1, along with their discount rates.

Table 1; Financing Scenarios

S.No.	Financing scheme	Discount rate
B	Base case; Domestic loan at an interest rate of 8%, 15year term with a grace period of 6 years	8.68
F1	Loan, financed through ODA at 0.3% for 20 years, with a grace period of 10 years.	6.33
F2	JBIC ODA at 0.90% for 20 years and a grace period of 6 years (untied, as applicable to Philippines; http://www.jbic.go.jp/english/oec/standard/	6.66
F3	OECD commercial loan at 5% for 10 years, with a grace period of 1 year (construction period).	8.96
F4	Danida financing; 35% grant and balance 65% as loan at 7%, 10 year term	9.80

Note: Loan amount is 80% of the total investment in all the scenarios. Balance 20% is equity contribution by the Investor. Data for scenarios 1 to 5 is based on common knowledge of these available loans. These may also change from time to time. Foreign exchange risk cost is taken as 1.5% and guarantee fee as 2% (as applicable to private investors in Philippines), except for Danida (1.5%).

2.2.5 Results

Base case and variations: The results of the base case and its variations for Sta. Ana are given in Table 2.

It can be seen that the project has positive NPV in the base case even without the CDM. This is because discount rate is only 8.68%. But if risk adjusted discount rate of 13.2% were considered, NPV is negative even with CDM (with CER at $10/t). IRR of the project is below 10% without CDM, and marginally above 10% with CDM. MIRR is below 8% even with the CDM, indicating need for concessional finance. It is because of the assumption that intermediate cash flows from the project can be invested only at 6%, and intermediate investment (- ve cash flows) incur 10.5% interest rate. As can be expected, all the variations, except electricity tariff increase, further reduce the attractiveness of the project. Of the three variations- investment increase by 20%, electricity generation less by 20%, and O & M cost increase by 20%- electricity generation reduction has the most adverse impact on the project, indicating importance of reliable wind measurements.

Table 2; Base Case and variations (NPV in million P)

Indicator	**Base case**	**Elect Tariff +10%**	**Investment +20%**	**El. Gen. - 20%**	**O&M costs +20%**
NPV 8.68% (hurdle rate)	243	614	-230	-385	138
With CDM; $6/t	379	750	-95	-276	273
With CDM $10/t	469	840	-5	-204	364
NPV 13.2%	-553	-278	-1052	-1020	-632
With CDM; $6/t	-453	-178	-951	-939	-531
With CDM; $10/t	-386	-110	-884	-885	-464
IRR	9.83%	11.53%	7.75%	6.79%	9.33%
With CDM; $6/t	10.46%	12.14%	8.30%	7.33%	9.97%
With CDM; $10/t	10.87%	12.54%	8.66%	7.69%	10.39%
MIRR	7.56%	8.16%	6.75%	6.35%	7.37%
With CDM; $6/t	7.78%	8.36%	6.97%	6,58%	7.61%
With CDM; $10/t	7,93%	8.50%	7,11%	6,72%	7.76%
IRR-Investor	14.03%	21.08%	7.28%	4.71%	12.26%
With CDM; $6/t	16.47%	23.93%	8.89%	6.13%	14.57%
With CDM; $10/t	18.19%	25.89%	10.02%	7.11%	16.20%

Increase in electricity purchase price by 10% increases the attractiveness of the project, indicating importance of price reforms for viability of renewable energy projects. Although IRR improved, it was still below 13.2%, the rate which reflects risk and higher cost of finance for a majority of private developers. Addition of CDM revenues in these cases makes project marginally better.

Financing scenarios results: These can be seen in Table 3.

Since all loans are concessional, they impact hurdle rate of the project developer, and consequently discount rate for NPV. ODA loan is obviously best option from the NPV perspective when discount rate for the scenario was considered, which is lowest at 6.33%. But IRR of this option is marginally lower than the others, mainly because tax paid is higher (due to lower interest charge). But IRRs are below 13.2% in all cases except the one with 35% grant (F4; Danida loan).

Table 3; Financing Scenarios **(NPV in million P)**

Indicator	Base case DBP 8%;15 yr, GP 6 yr	F1 ODA 0.3%;20yr, GP 10 yrs	F2 JBIC 0.90%;20 yr, GP 6 yrs	F3 OECD 5%;10 yr, GP 1 yr	F4 Danida 7%;10 yr (grant 35%), No GP
NPV 13.2%	-553	-616	-610	-609	66
With CDM; $6/t	-453	-516	-510	-508	167
With CDM;$10/t	-386	-448	-443	-441	234
Hurdle rate	8.68%	6.33%	6.66%	8.96%	9.80%
NPV	243	753	667	103	567
With CDM; $6/t	379	915	824	236	692
With CDM;$10/t	469	1023	930	324	776
IRR	9.83%	9.41%	9.45%	9.46%	13.76%
With CDM; $6/t	10.46%	10.05%	10.09%	10.10%	14.60%
With CDM;$10/t	10.87%	10.47%	10.51%	10.52%	15.15%
MIRR	7.56%	7.40%	7.41%	7.41%	8.81%
With CDM; $6/t	7.78%	7.63%	7.65%	7.65%	9.06%
With CDM;$10/t	7,93%	7.78%	7.80%	7.80%	9.22%
IRR-Investor	14.03%	50.73%	45.17%	13.32%	21.33%
With CDM; $6/t	16.47%	53.50%	48.20%	14.71%	23.24%
With CDM;$10/t	18.19%	55.34%	50.19%	15.67%	24.54%

3 Conclusions

Sta. Ana project is viable in the base case, when assumed a favourable domestic financing package, which reduces the discount rate for the project to 8.68%. CDM in this case adds to the attractiveness of the project. However, if favourable domestic financing package is not available, and risk adjusted discount rate of 13.2% is used (applicable for most developers- 13% to 18% discount rate), NPV of the project turns negative. CDM makes only marginal impact on project viability. Electricity tariff increase (by 10%) can make project attractive but the IRR at 12.5 % (with CDM) still remains below 13.2%. As expected, all other variations- investment increase, electricity generation decrease etc. make project unattractive.

Special financing packages, that include a variety of ODA low interest loans, increase the project attractiveness, but IRRs remain below risk adjusted discount rate of 13.2%, making the NPV negative at this discount rate. CDM impact is only marginal, and does not change project viability status. However, one of the financing package, that includes grant (Danida, with 35% grant) is able to address the issue of viability, as IRR increases to 13.8, and goes up to 15.2% with CDM.

It needs to be noted that the results in the study correspond to the assumptions made, and are sensitive to changes in that. It is therefore important to check the assumptions for correctness, and revise if necessary, before arriving at a conclusion. It also needs to be noted that discount rates used in the study are based on a variety of financing options, most of which are low cost. Most developers, especially small investors may not have access to these concessional and favourable financing packages. In that case, appropriate discount rate (which will be higher) will need to be used. Further, risk adjustment has not been made (except for foreign exchange risk) in the discount rates used. Spread (or the loan- return above cost of loan) has also been taken only 2%, and required return on equity only 11%. All these may vary across developers; may be low for public sector and high for private sector. When all these factors are included, required IRR will be higher- expected to be between 13 to 18%. Project is not viable at discount rates higher than 11% in case of Sta. Ana in the base case (even with a favourable financing package), indicating need for further financial support.

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Annexure 1; Data and assumptions for Sta. Ana

	(2006 prices)
1. Debt - Equity ratio	80: 20
2. Total investment $51766254 ; (excludes investment in transmission lines for grid connectivity) (1$=52 P)	2691845208 P
3. O & M costs per year $1059526	55095352 P
4. Rate of increase of O & M costs	3% per year
5. Grid Access charges	0.80 P/ KWh
6. Electricity Production	
(assumed to reach 100% capacity utilization in the first year of operation)	80 GWh
7. Losses in transmission to point of sale to distribution company	7%
8. Plant life	20 years
9. Tax rate	(i) Nil for first 6 years
	(ii) 30% after 6 years of operations.[6]
10. Sale price of electricity (2006)	4.91 P / KWh
11. Rate of increase of electricity sales price	3%
12. GHG saving coefficient of the power for CDM	0,625 CO2 eq./MWh
13.CER prices used for CDM revenue calculations (1CER= 1 ton of CO2eq.)	$6 and $10 per CER
14. Discount rate (Calculated based on financing packages)	8.68% base case; 13.2% risk adjusted minimum needed by private developers
15. Re-investment rate of the cash flows	6%
16. Re-finance rate (if needed; which is interest rate for intermediate negative cash flows i.e. short-term loans)	10.5%
17. Rate of depreciation (for tax purposes)	5% assumed

Other assumptions:

1.Construction period has been taken as one year. After construction period, year plant comes in full operation (at 100% capacity).

2 The investment is done in the first year (beginning), and cash flows from sale of electricity start from the next year (year-end).

3. Principal loan amount is assumed to be paid equally over the life of the loan. Interest for the full previous year on the outstanding amount is paid in the current year. Amortization of the loan and interest can be done for equated installments, but has not been done here.

4. MIRR is an improvement over IRR. This is because IRR assumes that intermediate cash flows can be invested at the same rate (as IRR), whereas, actually possible re-investment rate can be specified in the MIRR. A re-investment rate of 6% was taken here.

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6 From the data, although tax is 35% currently, it is 30% from 2009.

5.Impact of tax holidays for renewable energy (for first six years) on wacc was not considered.

6. Depreciation has been taken on the entire investment at 5% per year.

7. Terminal value (or salvage value) at the end of plant life of 20 years was taken as 10% of the original investment.