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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

Guanacaste Wind Farm
Version 10.
Date: 18/08/2010.

A.2. Description of the project activity:

The Guanacaste Wind Farm Project (hereafter referred to as "PEG") is being developed by Planta Eólica Guanacaste S.A. (hereafter referred to as "Project Participant"), a company owned by Enerwinds de Costa Rica S.A., (owner of a 90% equity stake) and Juwi S.A. (owner of a 10% equity stake). The controlling shareholder of Enerwinds and driving financier and force for the development of the Project was Econergy International Plc, (hereafter referred to as "Project Developer") a group active in the development of renewable energy and emission reduction projects that has been acquired by the GDF-Suez group in October 2008.

This project is located at Provincia de Guanacaste in the northwest of Costa Rica (hereafter referred to as the "Host Country"). The proposed project will use wind power to generate renewable electricity, which will be delivered to the national grid of Costa Rica (hereafter referred to as the "Grid"). The renewable electricity produced by PEG will avoid CO_2 emissions from electricity generation by fossil fuel power plants. This substitution effect is especially strong as the project activity has the great advantage of generating electricity during the dry season when the generation capacities of hydro power plants are reduced and thermal plants are demanded most.

This project will involve the construction of 55 wind energy converters (WECs) with 900 kW of installed capacity each, totaling 49.5MW. These generators will be operated at the top of the towers at 45m height above the ground. The rotor diameter has 44m with 3 blades of 22 meters each. The wind site has an average wind speed of 12 m/s and an average capacity factor of approximately 56.6%, resulting in a projected (P50) average generation of 245.3 GWh/year when all phases are concluded.

The project will contribute to the sustainable development of Costa Rica as it will foster and stimulate the expansion of renewable energy technologies, reduce the country's dependency on fuel imports and consequently improve its trade balance. Furthermore, by demonstrating the viability of larger grid-connected wind farms, the project will strengthen and diversify the national energy supply, foster the development of sustainable energy technologies, and improve local living standards.

Other benefits to sustainable development in Costa Rica are summarized below:

- Increasing the share of renewable power generation at the level of the regional and national grid;
- Preventing lack of power supply and increasing its stability and reliability;
- Reducing GHG emissions compared to a business-as-usual scenario;
- Improve air quality by reducing other power generation industry pollutants (SO_x, NO_x, particulate material, etc.);
- Stimulating the growth of the wind power industry and supply services in Costa Rica;
- Preserving natural resources including land, forests, minerals, water and ecosystems;

- Increase the participation of private investors in the energy sector that is still dependent on state owned generation;
- Creating job opportunities in the project area.

The following jobs are estimated to be generated during the construction phase by this project activity:

Equipment (WECs)	50
Substation	20
Balance of Plant	100
Development	10
Construction Management & Supervision	10
Lodging & Food Services	20
Total Construction jobs	**210**

Table 1. Estimated jobs during construction phase

The work force responsible for operation and maintenance will be contracted locally. The estimated direct job creation during the operational phase is listed in the table 2 below:

Operations and Maintenance	10
Administration	2
Local Management and supervision	1
Total Operations jobs	**13**

Table 2. Estimated direct jobs during operations

A.3. Project participants:

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)
Costa Rica (host)	• Planta Eólica Guanacaste, S.A. (Private Entity)	No
Netherlands	• Electrabel NV/SA	No
(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party(ies) involved is required.		

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

District of Mogote, Canton of Bagaces, Province of Guanacaste, Costa Rica.
Geographic coordinates: 10° 46'58" N; 85° 16'34" W.

A.4.1.1. Host Party(ies):

Costa Rica

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

Guanacaste

A.4.1.3. City/Town/Community etc:

Bagaces canton, Mogote district

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

PEG is located in Guanacaste province, in Bagaces canton, Mogote district, totaling around 200 hectares. The Guanacaste province is located in the northwest of Costa Rica and is a border province to the south of Nicaragua.

Picture 1 - Costa Rica and Guanacaste province location

Picture 2 - PEG location

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

Sectoral Scope 1: Energy industries – renewable/non renewable sources;

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

The project will use an environmentally safe and sound technology in the electricity sector. The renewable electricity generated by the project activity 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) in the baseline scenario. The project activity will install 55 ENERCON E-44 900 kW wind energy converters (WECs). These WECs are known for their gearless variable speed design, eliminating the risk of gearbox failure.

At the time of the project starting date, the project activity was expected to be installed in two Phases. Construction of Phase 1 was expected to start in November 2007 with the installation of 28 WECs and the operation of these WECs was projected to start in November 2008. Phase 2 was expected to start its operations in January 2009. Due to unexpected delays, Phase 1 effectively started its operation in September 2009 and Phase 2 is operational since December 2009.

Table 3 below presents a summary of the technology to be employed in this project.

WEC manufacturer	Enercon (1)
Type	E-44 (1)
Total capacity	900 kW each (1)
Capacity factor (P50)	56.6% (2)
Number of WECs	55 (1)
Lifetime	18 years (3)
Rotor diameter	44 m (3)
(1) WEC purchase agreement [1] (2) Wind Study[2] (3) Design Assessment[3]	

Table 3. Technical detail of the project activity

Considering the P50 capacity factor of 56.6% as projected by the Wind Study developed by RAM, the expected average net power supplied to the grid is 92,646 MWh/yr during first phase (operation of 28 WECs) and 245,300 MWh/yr when both phases are operational, i.e. with all the 55 WECs in operation.

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

A fixed crediting period was selected for this project activity. The average estimated emissions reductions is 95,225 tCO_2 per year during the crediting period.

[1] Contract Agreement between PEG and Enercon for the purchase of WECs, contract no. W-03371-V01

[2] RAM Associates: Wind Resource Assessment for a 50 MW Wind Farm at La Gloria, Costa Rica, developed by on June 2007.

[3] DEWI-OCC Offshore and Certification Centre GmbH: State of Compliance for the Design Assessment, STC – 070901, Rev. 1.

Year*	Annual estimation of emission reductions in tones of CO2e
2011	87,290
2012	95,225
2013	95,225
2014	95,225
2015	95,225
2016	95,225
2017	95,225
2018	95,225
2019	95,225
2020	95,225
2021	7,935
Total estimated reductions (tonnes of CO2e)	952,250
Total number of crediting years	10
Annual average over the crediting period of estimated reductions tonnes of CO2e)	95,225

*from 1 February 2011 to 31 January 2021

Table 4. Annual estimation of emissions reductions

A.4.5. Public funding of the project activity:

There is no public funding from any Annex I Party for this 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:

- Methodology used for baseline calculations and monitoring: ACM 0002 – *"Consolidated baseline methodology for grid-connected electricity generation from renewable sources"* version 11;
- "Tool to calculate the emission factor for an electricity system" version 02;
- "Tool for the demonstration and assessment of additionality" version 05.2.

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

The approved baseline methodology ACM0002 is applicable to grid-connected renewable power generation project activities that: a) install a new power plant at a site where no renewable power plant was operated prior implementation of the project activity (greenfield plant); (b) involve a capacity addition; (c) retrofit of (an) existing plant(s); or (d) involve a replacement of (an) existing plant(s).

The proposed project activity is a greenfield wind power plant, does not involve switching from fossil fuels to renewable energy source, is not a biomass fired power plant, and the geographic and system boundaries of the grid can be clearly identified and information on the grid is available.Therefore, the project activity is applicable to ACM0002.

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

According to the methodology, the spatial extent of the project boundary includes the project site and all power plants connected physically to the electricity system that the PEG will be connected to.

Electricity system: The National Interconnected System (NIS) is the defined electricity system for the project activity. It is controlled and operated by the Electricity Institute of Costa Rica (*Instituto Costaricense de Electricidad ICE* – a vertically integrated national utility) and all power plants connected to it are included in the project boundary.

PEG: The project site where PEG is installed is included in the project boundary.

	Source	Gas	Included?	Justification/Explanation
Baseline	CO_2 emissions from electricity generation in fossil fuel fired power plants that is displaced due to the project activity.	CO_2	Yes	Main emission source.
		CH_4	No	Minor emission source.
		N_2O	No	Minor emission source.

Since project activity is a wind farm project, no project emissions are accounted for PEG. This is assumption is in line with ACM0002.

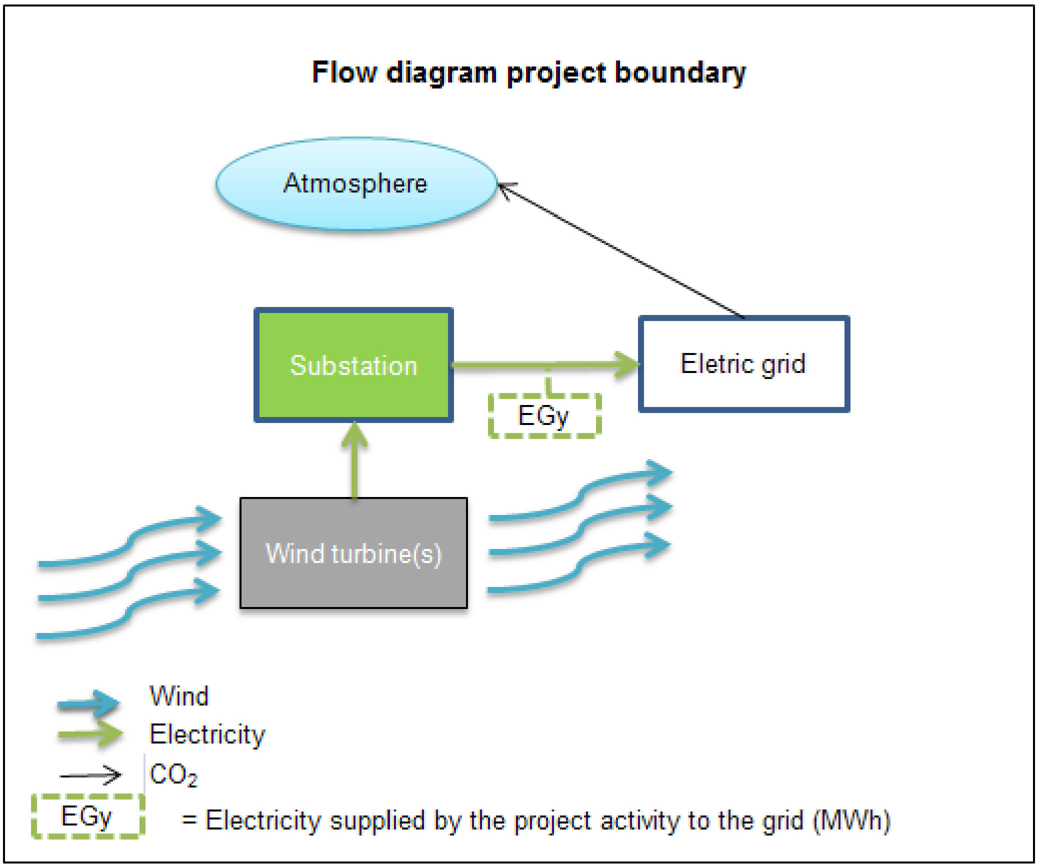

Figure 1. Flow diagram project boundary

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

The project activity is the installation of a new grid-connected renewable power plant/unit. It does not modify or retrofit an existing electricity generation facility. Therefore, in accordance with ACM0002, 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 in the "Tool to calculate the emission factor for an electricity system".

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 approved methodology ACM0002 requires the use of the latest version of the *"Tool for the demonstration and assessment of additionality"* agreed and approved by the Executive Board. The latest available version (05.2) was used.

In order to register this project activity, the Project Developer took the following steps:

Date:	Details
February 2006	CDM evidence (Project Developer admission to trading on the AIM market)
09 February 2007	Econergy Brasil Ltda started working on PEG's CDM Project (evidenced by an internal email)
17 July 2007	Financial decision making (signature of contract agreement for purchase the WECs). This is considered the CDM starting date.
February 2008	Construction Works Started
12 December 2007	Request for validation proposal (evidenced by an email requesting proposal)
28 May 2008	Validation contract signed

Table 5. Project timeframe

These steps includeCDM activities undertaken prior to the starting date of the project activity as well as continuing and real actions to achieve CDM status, as required by paragraphs 102 (a) and (b) of the VVM[4].The starting date of the CDM project activity was defined as the purchase of the WEC, a contract that implies a cost of approximately € 48 Million and therefore the major share of the total capital expenditure. All activities undertaken before were preparative and did not imply significant expenditures, but created the precondition to finance the project implementation. This complies with the definition of the CDM Glossary of Terms, Version 03: "*The starting date of a CDM project*

[4] A detailed description of the Project Developer admission to trading on the AIM market (Econergy IPO process) and the fact that CDM was a decisive factor in the decision to proceed with the project is presented in sections 2(b) and 3(a) (ii) and 3(a) (iii) of the PDD.

activity is the earliest date at which either the implementation or construction or real action of a project activity begins", as well as with the respective clarifications provided at EB 41:

"*In light of the above definition, the start date shall be considered to be the date on which the project participant has committed to expenditures related to the implementation or related to the construction of the project activity. This, for example, can be the date on which contracts have been signed for equipment or construction/operation services required for the project activity. Minor pre-project expenses, e.g. the contracting of services /payment of fees for feasibility studies or preliminary surveys, should not be considered in the determination of the start date as they do not necessarily indicate the commencement of implementation of the project*."

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

Define realistic and credible alternatives to the project activity that can be the baseline scenario through the following sub-steps:

Step 1a. Define alternatives to the project activity:

a) <u>Alternative 1:</u> The proposed project activity - construction of a new wind energy development with an installed capacity of 49.50 MW - not undertaken as a CDM project.

b) <u>Alternative 2:</u> Continuation of the current situation (no project activity or other alternatives undertaken).

Step 1b. Consistency with mandatory laws and regulations:

All above mentioned alternatives are in compliance with all mandatory applicable legal and regulatory requirements of Costa Rica.

Step 2: Investment analysis

The "Tool for the demonstration and assessment of additionality" (Version 05.2) states that project participants may choose to apply Step 2 (Investment analysis) or Step 3 (Barrier analysis) to demonstrate the additionality of the project. As will be shown under Step 3, Barrier Analysis, PEG faced significant investment barriers and the CDM was crucial to secure financing for the project. Further, under the situation of lack of access to capital markets for equity and debt, as will be demonstrated below, the Investment Analysis is not a meaningful additionality criterion[5]. Nevertheless the project developers opted to conduct Step 2 as well in order to complement and illustrate the additionality as proved by barrier analysis. Accordingly, the Investment Analysis shall determine whether the proposed project activity is not:

a) The most economically or financially attractive; or
b) Economically or financially feasible, without the revenue from the sale of certified emission reductions (CERs)

To conduct the investment analysis, the PP used the following steps:

[5] Damodaran, Aswath, Corporate Finance. Theory and Practice. 2nd Edition. John Wiley & Sons 2001, pgs. 362 – to 369.

Sub-step 2a: Determine appropriate analysis method

The Option III – Benchmark analysis was used.

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

For the purpose of this investment analysis, the IRR was deemed the most suitable indicator. The appropriate benchmark for comparison as presented below was defined according to the "Tool for the demonstration and assessment of additionality" (Additionality Tool) and in line with the "Guidance on the Assessment of Investment Analysis" (Guidance on Investment Analysis). As such, it is based on standard market parameters that consider the specific characteristics of the project type, but are not linked to the subjective profitability expectation of a particular project developer.

To allow the proper definition of a benchmark based on market parameters that are specific to the project in question, some background information about the project development and its search for financing from capital markets is required. Most of the information presented is available in the Econergy IPO Admission Document[6] (IPO Document).

The Project Developer, Econergy, was founded in 1994 as a consulting company in the US, later becoming a company with the mission to develop renewable energy and emission reduction projects (IPO Document, page 9-10). At the time, this innovative business model was not financed by standard capital markets and on 02 September 2005 Econergy signed a CER Loan Agreement to obtain USD 4 million earmarked for the purchase of CERs and investments in Project Development entities (IPO Document, page 11). The financing agreement further specified that the loan shall be repaid by the delivery of CERs only, i.e. no financial repayment was allowed by the creditor (IPO Document, page 47).

This initial financing allowed Econergy to prospect investment opportunities with CDM potential as it was Econergy's mission and obligation under the CER Loan Agreement. Alongside with the development of other mainly renewable energy projects in Latin America, Econergy, acting through its subsidiary Enerwinds S.A. in Costa Rica [page 119], initiated the development of PEG (referred to as "Guayabo" Project in the IPO Document).

With this specific business model of investing in CDM and Renewable energy projects, Econergy prepared the IPO Document to launch into the Alternative Investment Market (AIM) in the London Stock Exchange, in order to obtain the capital needed to implement the projects listed in the IPO Document. In the Admission Document (page 13) Econergy commits to using over 90 % of the net proceeds of the IPO to *"make direct equity investments in clean energy assets in emerging markets, with initial emphasis on Latin America and the Caribbean ("LAC"). These assets have the potential to produce a dual revenue stream from the sale of both energy and Carbon Credits."* The project PEG and the intention to pursue the CDM status for this particular project is clearly stated in the IPO Document (page 16). Therefore, the development of PEG and its CDM registration were a central part of the Econergy business model. Also, the IPO Document (pages 26 and 48) explicitly alerts potential investors that the development of renewable energy projects in emerging markets are subject

[6] Econergy International PLC, Admission to trading on AIM, February 20,2006; available from: http://web.archive.org/web/20060602205507/www.econergy.com/investor_relations/admissions_document/Econergy_Admissions_Document.pdf, accessed on 8 February 2010

to numerous risks that shall be taken into account for the appraisal of the offer. Specifically the risks described are:

- Political risks;
- Contractual risks;
- Currency risks;
- Operating and performance risks;
- Difficulties in securing the non-recourse project finance modality as proposed;
- Regulatory risks;
- Possible adverse economic conditions and emerging markets risk
- Liquidity Risk: AIM is a market for emerging or smaller growing companies and may not provide the liquidity normally associated with the Official List or other exchanges. (page 44);

In addition to these risks, the AIM informs on the header of the IPO Document (page 1) that an *"investment in Econergy International PLC involves a high degree of risk and particular attention is drawn to the risk factors set out in Part V of this document."*

Further, the AIM clarifies: *"AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies."*

Considering the risks associated to Econergy business model, the IPO Document defined that a return of 20% p.a. for shareholders equity should compensate the investors for these risks (page 9). To understand the relevance of this statement for the discussion of an appropriate benchmark we have to consider that:

i) PEG is not only "characteristic of the project type" proposed in the [Econergy] Business Model, but a central part of the proposal;

ii) The IPO Document was developed under advisory of Numies Securities Limited, being advisory a regulated activity in the UK according to the rules of AIM and the London Stock Exchange.[7]

iii) Econergy was admitted to AIM with this IPO Document; and

iv) The capital was fully underwritten by private and institutional investors (banks, pension funds, family funds and other equity funds) as listed in Table 6 below.

Name	Shares aquired in IPO	
	N°	%
Elsina Limited for Tchenguiz Family Trust	15,935,700	18.32%
Ospraie Management	12,182,963	14.00%

[7] According to the IPO Document [page 1]: *"Numis Securities Limited, which is authorised and regulated in the UK by the Financial Services Authority and is a member of the London Stock Exchange, is the Company's Nominated Adviser and Broker for the purposes of the AIM Rules and is acting exclusively for the Company in connection with the Placing and Admission. [...] Its responsibilities as the Company's Nominated Adviser under the AIM Rules are owed solely to London Stock Exchange plc and are not owed to the Company or to any Director or to any other person who may rely on any part of this document"*. Econergy is the "Company" referred to in this text.

Scottish Widows	8,659,952	9.95%
MPC Investors	7,536,950	8.66%
HSBC Investments	5,376,812	6.18%
Thomas H. Stoner Jr.	5,673,039	6.52%
MF Global	4,334,000	4.98%
Moore Capital Management	4,000,000	4.60%
Merrill Lynch	3,695,000	4.25%
Frederick Renner	2,766,425	3.18%

Table 6. Econergy main shareholders after the IPO[8]

Based on the facts mentioned above, the expected rate of return of 20% as defined in the IPO Document must be seen as an estimate "of the cost of financing and required return on capital, (…) based on bankers views and private equity investors/funds required return on comparable projects", as defined by the Additionality Tool.

Though not required by the Additionality Tool, Econergy has also provided confidential evidence to the audit team that this benchmark was applied for evaluation and approval of other projects undertaken by the company.

To further reference and obtain a more specific benchmark for the case of PEG, and in reference to the Additionality Tool, which allows to define a benchmark based on "*Government bond rates, increased by a suitable risk premium to reflect private investment and/or the project type, as substantiated by an independent (financial) expert or documented by official publicly available financial data"*, the project participants requested KPMG as independent financial expert to estimate the cost of capital for wind power investments such as PEG in Costa Rica. In reference to the Additionality Tool, KPMG applies the Capital Asset Pricing Model (CAPM) to measure the cost of equity for wind investments with the characteristics of PEG by combining government bond rates and suitable risk premium that reflect the characretristics of the PEG investment. For this purpouse KPMG used prestigious publicly available data and references that are standard in the market. Consequently, the cost of equity as calculated by KPMG represents the minimum return required by equity investors at the project start date for an investment like PEG in the specific case of Cost Rica.

The CAPM is a standard tool in corporate finance that postulates that the cost of equity is a linear function of the company's exposure to systemic risk.[9] The CAPM specification used by KPMG for the benchmark estimation is the following:

$$k_e = r_f + \beta \times ERP + SRP + CRP + CSRP$$

Where:

[8] Econergy Internacional PLC 2007 Annual Report

[9]The CAPM was introduced in the financial literature during the 1960's by several authors, including: Sharpe, W. F. (1964) Capital Asste Prices: A Theory of Market Equilibrium, Journal of Finance; Lintner J. (1965) The Valuation of Risk Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets, Review of Economics and Statistics; and Mossin, J (1966) Equilibrium in a Capital Market, Econometrica. The CAPM is presented in many corporate finance textbooks; see for example Lawrence J. Gitman, Principles of Managerial Finance, Tenth edition; Damodaran, Aswath, Corporate Finance. Theory and Practice. 2nd Edition. John Wiley & Sons 2001; or Brealey, R.A., Myers, S. C, y Allen, F, 2006, Principles of Corporate Finance. Eight Edition. McGraw-Hill. The CAPM is also analyzed in Ibbotson & Associates, "*Stocks, Bonds, Bills and Inflation, 2007 Yearbook (Valuation Edition).*

Ke:cost of equity;
R_f: Risk free rate
β: Equity beta
ERP: Equity Risk premium
SRP: Size risk premium;
CRP: Country risk premium
CSRP: Company-specific risk premium

According to KPMG the cost of equity can be estimated by measuring and adding the cited parameters and a further brief description of the variables and the sources used by KPMG for their estimation is provided below:

- *Risk free rate (R_f)* Since any risky investment should return at least as much as the riskless asset, the risk-free rate is the starting point of the CAPM. This method implicitly assumes the presence of a single riskless asset, that is, an asset perceived by all investors as having no risk. A common choice for the nominal riskless rate is the yield on a U.S. Treasury security. The horizon of the chosen Treasury security should match the horizon of the activity being valued. For the PEG case, KPMG has chosen the US-TBond with 20 years maturity as released by the Federal Reserve Bank. The value applied is 5.3%.

- *Equity risk premium (ERP).* The market risk premium is the difference between the expected rate of return of the market as a whole, and the risk free rate. It quantifies the return in excess of the risk free rate which is required by investors to invest into a well diversified portfolio of equities. Therefore, the market risk premium does not include Costa Rican country risk premium, and does not reflect the higher or lower risk exposure of specific sectors, firms or projects.

  The market risk premium used by KPMG for estimating the cost of equity has been obtained by KPMG from Ibbotson & Associates. The value used was 7.1%.

- *Equity beta (β).* The equity beta is the measurement of the risk of a security or portfolio that can not be eliminated by investors through diversification (i.e., its *systematic risk*). The equity beta can be estimated from the betas of securities (or portfolios) with risk characteristics that are similar to the activity in question. For the assessment of the cost of equity for a project activity like PEG, KPMG choose the average beta calculated by Ibbotson & Associates for the Electric Sector in the US and adjusted it for the leverage of the PEG investment. The value calculated for the beta by KPMG is 0.84.

- *Size premium (SP).* According to KPMG *"there are several empirical studies performed since CAPM was originally developed indicating that realized total returns on smaller companies have been substantially greater over a long period of time than the original formulation of the CAPM would have predicted.*" In general, the use of a size premium is justified by the fact that small capitalization stocks are considered riskier than large capitalization stocks. In the specific case of Econergy and PEG, this is also justified by the following disclaimer made by the AIM: "*AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies."* [IPO document, page 1] KPMG defined the SP to be 3.6% based on the SBBI Valuation Eddition.

- *Country risk premium (CRP):* Emerging markets' lower degree of diversification to the world goods and financial markets represent the main causes for the country risk premium. Investors may view some country-level factors as country-specific and demand a premium due to risks of financial, economic, and political nature, such as currency volatility, losses from exchange controls, volatility of the economy, inflation, labor issues, economic planning failures, political leadership and frequency of change, poorly developed legal system and other. KPMG calculated the CRP based on the spread between the Costa Rica sovereign debt and the US Treasury Bonds to be 1.9%.

- *Company-specific risk premium*: According to KPMG *"The notion that the only component of risk that investors care about is market or systematic risk is based on the assumption that all unique or unsystematic risk can be eliminated by holding a perfectly diversified portfolio of risky assets with beta of 1.0. Particularly in the case of closely held companies, it is difficult to hold such a perfectly diversified portfolio that would eliminate all unique risk. Therefore, for the cost of capital for closely held companies, other risk elements should be considered, that neither beta factor nor size premium or country premium accounts for.*" Based on their professional experience KPMG has choosen a value of 1.0% as appropriate for investmenst like PEG in the specific context of Costa Rica.

As a result, the nominal post-tax cost of equity estimated by KPMG for investmenst like PEG is 17.7%. This cost of equity is slightly lower, but still coherent with Econergy´s expected rate of return, 20%, which was defined in Econergy's IPO Document, and which was used by Econergy for the evaluation and approval of other similar projects undertaken by the company, as demonstrated to the DOE.

Table 7 summarizes the calculation of the cost of equity as provided by KPMG. The full report was provided to the DOE

Risk Free Rate (R_f)	5.3%
Equity Beta (β)	0.84
Equity Risk Premium (ERP)	7.1%
Size Risk Premium (SRP)	3.6%
Country Risk Premium (CRP)	1.9%
Company-specific risk premium (CSRP)	1.0%
Total	**17.7%**

Table 7. PEG Benchmark

Sub-step 2c: Calculation and comparison of financial indicators

The IRR was calculated using the 20-year Free Cash Flow to Equity (FCFE) model for PEG as it was assumed 2 years for construction and 18 years for operation in accordance with the wind turbine manufacturer specifications, as well as the BOT (Build Operate and Transfer) contract that implies that after 18 years of operation the plant will be transferred to ICE without any financial compensation. Also, all information used was available at that moment invesment decision was made (July 2007). The main assumptions for the investment analysis are presented below:

Data	Value used	Description	Evidence
First Phase COD	November 2008	Installation of 28 WECs	Econergy 2006 annual report
Second Phase COD	January 2009	Installation of 27 WECs	Econergy 2006 annual report

Electricity price (average)/Monomic Price	USD 0.06331 / kWh	Value calculated in accordance with PPA assumptions (PPA defines high season and low season electricity prices)	PPA pages 19-22. For variations along the year, see page 19 of PPA.
Electricity generation	245,300 MWh/year for 55 WECs in operation	P-50 estimate as suggested by the engineering company for use in the investment analysis.[10]	Wind Resource Assessment for a 50 MW Wind Farm at La Gloria, Costa Rica
O&M costs	16.5% of the revenue	Value estipulated in the PPA	PPA page 24
Operation Insurance	690,000 USD	Value estimated at project start	Insurance evidence files
Other Administrative	50,000 USD	Value was estimated at project start and is lower than incurred expenses as evidenced by the Contract with Enerwinds for Management Services.	Contract for the provision of Management Services
Guarantees-Compliance /Environmental	190,000 USD	Value was estimated at project start.	Comission quoted by HSBC (2%)
Majour Maintenance	1,000,000 USD	Value was estimated at project start for years 2017 and 2026	According to internal estimates.
Total Equity Requirement	28,438,000	Value was estimated as 30% of Project's Investment Costs.	According to BNPP LOI from 9 July 2007
Financial Debt	67,120,000	Value estimated as 70% of Project´s Investment Costs	According to BNPP LOI from 9 July 2007
Interests	Fixed rate of 8.69%, corresponding to a floating reference of Libor + 2.875% converted to a fixed rate by the use of an USD denominated interest rate derivative contract (interest rate swap) with 15 yrs. tenor	Value defined by the BNPP proposal, with the average USD denominated 15 yrs. interest rate swap rate of 5.82% as quoted daily by Bloomberg during the period 18 June 2007 to 16 July 2007.	BNPP LOI, 9 July 2007 Data from Bloomberg financial services (data during the period 18/06/2007 to 16/07/2007)

[10] The *GUIDELINES FOR THE REPORTING AND VALIDATION OF PLANT LOAD FACTORS* (EB48 annex 11) states that the plant load factor can be defined using third parties hired by the project participants, among others. In 2007, PEG hired the RAM Associates to perform a wind resource assessment of the project site.

	and a fixed interest rate of 5.82%		
Depreciation Factor	6%	Yearly depreciation factor (%) according to an operation period of 18 years from January 2009 (full Commercial Operation of 49.5 MW).	According to International Accounting Standard IAS 16 paragraph 56.
Other Taxes	30% (CIT), 13% (VAT) and 15% WHT	It includes: i) Tax rate for Corporate Income Tax (CIT - %); ii) Tax Rate for VAT ("Impuesto sobre las Ventas"). Not applied due to the expected full exoneration in the Sales Tax and Import Duties would be given for the purchase of equipment, materials and machinary, needed for the development of the Wind mill & the sale of power; iii) Tax Rate for WHT on Dividends. Only applies to remittances to shareholders non domicilated in Costa Rica.	All references provided by the Costa Rican government at: http://dgt.hacienda.go.cr .
Inflation	Variable, using US PPI and CR CPI projections.	US Price index (PPI), in accordance with the PPA and the Costa Rican consumer price index (CR CPI) for expenditures not considered in the PPA	http://www.ihsglobalinsight.com/
Working Capital Configuration	30 days for accounts payable and accounts receivable	Value estimated at project start	According to PPA invoice cycle.
Lifetime	18 years	Lifetime of the WECs, tower and hub	DEWI-OCC Offshore and Certification Centre GmbH: State of compliance for the design assessment, STC – 070901, Rev1.

Table 8. Main assumptions

The Capital expenditures at project starting date are detailed below:

CAPEX	Bugeted at project start (kUSD)	Evidence
Development Costs Subtotal **(**Engineering,Supervision,Others)	**2,547**	Value was estimated at project starting date and is in line with the realized expenditures of 2,553 kUSD as referenced by Shareholders Contributions, May 2009
Direct Costs Subtotal	**78,401**	
Land, access rights, other	3,773	Value was estimated at project starting date and is in line with the realized expenditures of 3,700 kUSD as referenced by Public Deeds (20-Jun-08 & 19-Sep-09)
WECs	66,300	WEC purchase contract with value of € 48,070 at exchange rate as applicable at project starting date (1€ = 1.3785 USD)[11]
Civil Works	4,228	Value was estimated at project start but the contract price was 10,131 kUSD, which is significantly higher than the numbers projected, even when considering that insurance was covered. Incured expenditures are referenced by Balance of Plant; Executed 23-May-08 (based on a exchange rate of 1 cólon = 0.0019610 USD)[12]
Substation	4,100	Value was estimated at project start and is lower than the realized expenditure of 5,700 kUSD as referenced by the Substation Construction Contract (Signed 16-Oct-07)
Indirect Costs Subtotal	**2,103**	
Taxes	978	Value was estimated at project start and considered the expectation that full exoneration in the Sales Tax and Import Duties would be given for the purchase of equipment, materials and machinary, needed for the development of the Wind mill & the sale of power. In fact these exemptions were granted later than expected (Sales tax exemption and Import Duty exemption) and as a consequence a tax expenditure of 5,755 kUSD accured, which had not been considered at project starting date. References are presented in Tax evidence file and sample documentation.

[11] http://www.oanda.com/lang/pt/currency/historical-rates?date_fmt=normal&date=31.07.07&date1=01.07.07&exch=USD&expr=EUR&format=HTML&margin_fixed=0, accessed on 5 February 2010

[12]http://www.oanda.com/lang/es/currency/historical-rates?date_fmt=normal&date=30.05.08&date1=01.05.08&exch=CRC&expr=USD&format=HTML&margin_fixed=0, accessed on 5 February 2010

Insurance (during construction)	1,125	Value was estimated at project start but in fact the insurance obligations later were included in the Civil Works, WECs and Substation contracts.
Other financial Subtotal	**12,507.5**	BNPP LOI, 9 July 2007
TOTAL	**95,558.48**	

Table 9. Capital Expenditures

The PEG equity investment in this project as budgeted at project start accounts for around USD 28 million, i.e. 30% of the total capital expenditures as up to 70% can be financed according to the BNP Paribas proposal. Considering this third party financing, the following table presents the Projects' Free Cash Flow from the perspective of the shareholders. In line with the inflation adjustment terms of the PPA and in harmony with the benchmark which was defined in nominal terms, the Cash Flow projection was elaborated in nominal terms.

CASH FLOW REPORT (´000 USD)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ELECTRICITY SALES		1,318	15,580	15,630	15,683	15,736	15,789	15,844	15,899	15,956	16,013	16,072	16,132
TOTAL NET SALES		1,318	15,580	15,630	15,683	15,736	15,789	15,844	15,899	15,956	16,013	16,072	16,132
O&M EXPENSES		217	2,571	2,579	2,588	2,596	2,605	2,614	2,623	2,633	2,642	2,652	2,662
TOTAL OPERATING COSTS		217	2,571	2,579	2,588	2,596	2,605	2,614	2,623	2,633	2,642	2,652	2,662
GROSS PROFIT		1,100	13,009	13,051	13,096	13,139	13,184	13,229	13,276	13,323	13,371	13,420	13,470
INSURANCE		115	703	717	731	745	760	774	789	805	820	836	852
GUARANTEES		190	190	190	190	190	190	190	190	190	190	190	190
MANAGEMENT		38	54	57	61	65	69	73	77	82	87	93	98
MAJOUR MAINTENANCE		0	0	0	0	0	0	0	0	0	1,000	0	0
TOTAL ADDITIONAL COSTS		343	947	964	982	1,000	1,018	1,037	1,057	1,077	2,097	1,118	1,140
EBITDA		758	12,062	12,087	12,113	12,139	12,166	12,192	12,219	12,246	11,274	12,302	12,330
DEPRECIATION		0	4,858	4,858	4,858	4,858	4,858	4,858	4,858	4,858	4,858	4,858	4,858
EBIT		758	7,204	7,229	7,255	7,281	7,307	7,334	7,361	7,388	6,415	7,443	7,471
INTEREST EXPENSES + OTHER FINANCIAL EXPENSES		-5,911	-5,784	-5,447	-4,998	-4,549	-4,100	-3,651	-3,202	-2,754	-2,305	-1,856	-1,407
INCOME TAXES		0	-426	-534	-677	-820	-962	-1,105	-1,247	-1,390	-1,233	-1,676	-1,819
NET EARNINGS		-5,153	994	1,247	1,580	1,912	2,245	2,578	2,911	3,244	2,878	3,911	4,245
DEPRECIATION		0	4,858	4,858	4,858	4,858	4,858	4,858	4,858	4,858	4,858	4,858	4,858
OTHER ADJUSTMENTS		0											
CAPEX	-95,558												
+/- WORKING CAPITAL INCR.		62	929	2	2	2	2	2	2	2	-80	84	2
DRAWDOWN OF DEBT	67,120												
DEBT REPAYMENTS			-2,582	-5,163	-5,163	-5,163	-5,163	-5,163	-5,163	-5,163	-5,163	-5,163	-5,163
FCFE	-28,438	-5,215	2,342	940	1,273	1,605	1,938	2,271	2,604	2,937	2,653	3,522	3,938
Project IRR to Equity	7.85%												

Continuing

CASH FLOW REPORT (´000 USD)	2020	2021	2022	2023	2024	2025	2026
ELECTRICITY SALES	16,193	16,255	16,318	16,383	16,449	16,516	16,584
TOTAL NET SALES	16,193	16,255	16,318	16,383	16,449	16,516	16,584
O&M EXPENSES	2,672	2,682	2,693	2,703	2,714	2,725	2,736
TOTAL OPERATING COSTS	2,672	2,682	2,693	2,703	2,714	2,725	2,736
GROSS PROFIT	13,521	13,573	13,626	13,680	13,735	13,791	13,848
INSURANCE	869	885	902	920	937	956	974
GUARANTEES	190	190	190	190	190	190	190
MANAGEMENT	104	111	118	125	133	141	150
MAJOUR MAINTENANCE	0	0	0	0	0	0	1,000
TOTAL ADDITIONAL COSTS	1,163	1,186	1,210	1,235	1,260	1,286	2,313
EBITDA	12,358	12,387	12,416	12,445	12,475	12,504	11,534
DEPRECIATION	4,858	4,858	4,858	4,858	4,858	4,858	4,858
EBIT	7,500	7,528	7,558	7,587	7,616	7,646	6,676
INTEREST EXPENSES + OTHER FINANCIAL EXPENSES	-958	-509	-172	-0	-0	-0	-0
INCOME TAXES	-1,963	-2,106	-2,216	-2,276	-2,285	-2,294	-2,003
NET EARNINGS	4,579	4,914	5,170	5,311	5,331	5,352	4,673
DEPRECIATION	4,858	4,858	4,858	4,858	4,858	4,858	4,858
OTHER ADJUSTMENTS				5,537			2,571
CAPEX							
+/- WORKING CAPITAL INCR.	2	2	2	2	2	2	-80
DRAWDOWN OF DEBT							
DEBT REPAYMENTS	-5,163	-5,163	-2,582	0	0	0	0
FCFE	4,272	4,607	7,444	15,704	10,187	10,208	12,182

Table 10. Free cash flow to equity as projected at project starting date

The nominal IRR of the projected cash flow without CERs is 7.85%, therefore it is lower than the benchmark applicable to the project activity. This shows that even under conditions in which access to capital markets for equity and debt financing is granted, the Project Activity is not economically or financially feasible. Consequently, the CDM benefits play an important role to improve the IRR, of the proposed Project Activity, and are also crucial to overcome several financial barriers to be shown under Step 3.

Sub-step 2d: Sensitivity analysis

The Project Participants conducted a sensitivity analysis, varying in a 10% range the revenue, the O&M costs and the capital expenditures. This range of variation is in line with the "Guidance on the Assessment of Investment Analysis" of the Additionality Tool, version 05.2. The impact of this variation is presented in Table 11 and Figure 2 below:

	Variation	IRR
CapEx	-10%	10.25%
	10%	6.01%
OpEx	-10%	8.28%
	10%	7.42%
Revenue	-10%	5.18%
	10%	10.42%
Base Case	0%	7.85%

Table 11. Sensitivity analysis

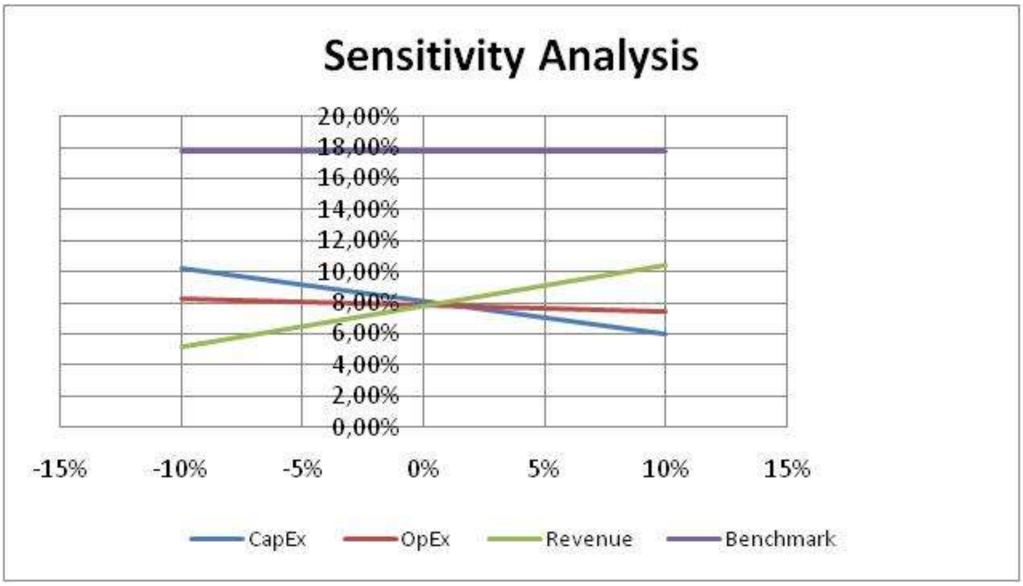

Figure 2. Sensitivity analysis

As per the data presented above, this project is not deemed financially attractive, as not even with the variation of 10% of the main value drivers the IRR reaches the benchmark.

The IRR would only reach the benchmark if:

- Revenues were significantly increased to USD 21,882 million (2010 value) (Revenue increased due to inflation only.). As the energy price is fixed by the PPA, this is only possible if the power generation reaches 343,418 MWh/y, which is 40%[13] more then the greatest value presented by RAM associates (P50 - 245,300MWh/y). Consequently, it is not a reasonable assumption that this generation volume will be reached on a regular basis.

- The Capex were reduced to 73,697 milion dollars, a variation of -23%. As the main expenditure is the purchase of the WECs and their price has been fixed (as stated above) at the project starting date, a significant reduction from the budgeted capital expenditures is not a reasonable assumption. On the contrary, it is always possible and quite common that the Capital Expenditures increase due to cost overruns as evidenced for the item *Civil Works* and *Substation* in Table 9. Additionaly, as there are no wind turbine manufacturers in Costa Rica, the contract had to be signed in Euros, adding a currency fluctuation risk to this project.

- O&M costs were reduced 242%. This is not a reasonable assumption as it would imply that instead of spending money to operate this project, PEG would receive additional payments.

These results show that only with highly unrealistic and very favourable circumstances it would be possible to reach the Project IRR benchmark. In reality, circumstances are typically more unfavourable than projected and the IRR would decrease even further away from the benchmark. We can conclude that the IRR is lower than the benchmark for a realistic range of assumptions for the input parameters of the sensitivity analysis, and therefore that the Project "is unlikely to be financially/economically attractive" as defined by the Additionality Tool.

Step 3. Barrier analysis:

This Step is used to show that the Alternative 1: "construction of a new wind energy development with an installed capacity of 49.50 MW - not undertaken as a CDM project" as defined under Step 1. a faces barriers that prevent its implementation, while Alternative 2: Continuation of the current situation (no project activity or other alternatives undertaken) is not prevented by these barriers.

To demonstrate that the barriers identified "would prevent project proponents from carrying out the proposed project activity undertaken without being registered as a CDM project activity" the project participantes use the definitions of the the Additionality Tool, and the "Guidelines for objective demonstration and assessment of barriers" version 01 (Guidelines for Assessment of Barriers).

Sub-step 3a. Identify barriers that would prevent the implementation of the proposed CDM project activity:

The following barriers have been identified to prevent the implementation of the proposed project activity from being carried out if the project was not registered as a CDM activity:

[13] 344,787 MWh is a result of the revenue (USD21,882 Million) divided by the monomic price (USD 63.31/MWh)

Investment Barriers, other than the economical/financial barriers described in Step 2 above:

(a) According to the Additionality Tool, an investment barrier is shown if "For alternatives undertaken and operated by private entities", as it is the case of the proposed project activity, "similar activities have only been implemented with grants or other non-commercial finance terms."

i) As will be shown in Step 4, Common Practice Analysis, i) wind energy in Costa Rica represents only 3% of the country Energy Matrix and all 4 projects operating in the country are of ii) different scale and iii) have been financed by non commercial financial terms and/or were supported by the CDM or Activities Implemented Jointly (AIJ). Moreover, three of them started operations before the year 2000. The Tejona Wind Farm, which is operational since 2002, was not only registered as CDM project, but also developed by Costa Rica's state-owned utility "Electricity Institute of Costa Rica" (*Instituto Costaricense de Electricidad* (ICE)), which controls the Costa Rica energy generation and distribution activities and therefore does not face the same risks or capital constraints as a private investor.

Result: The criterion is fulfilled and an investment barrier is confirmed.

(b) According to the Additionality Tool, an investment barrier is shown if "No private capital is available from domestic or international capital markets due to real or perceived risk associated with investment in the country where the proposed CDM project activity is to be implemented, as demonstrated by the credit rating of the country or other country investment reports of reputed origin."

i) The fact that private capital markets were not willing or able to finance energy investments in Costa Rica is demonstrated by the observation that the electricity market is subject to a government monopoly held by the "Electricity Institute of Costa Rica" (*Instituto Costaricense de Electricidad* (ICE)) which controls 78% of the total installed capacity in Costa Rica[14] and 76% of the total electricity generation[15]. If other state-owned companies (such as Heredia Public Services Company (ESPH – *Empresa de Servicios Publicos de Heredia*) and Cartago's Management Comission for Electric Services (JASEC – *Junta Administrativa de Servicios Eléctricos de Cartago*)) and cooperatives are included in this calculation, the private sector represents only 14.75%[16] (average from 2004 to 2006) of the power generation in Costa Rica. As a matter of fact the private sector can only own power generation assets up to a maximum of 20 MW, being obliged to sell its energy to the ICE. For generation assets with an installed capacity above 20 MW, as it is the case of PEG, the only feasible structure is to aquire a concession to Build, Operate and then Transfer (BOT)

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[14] Source: "*Capacidad instalada del sector electrico nacional 1999-2007*", available at: http://www.aresep.go.cr/cgi-bin/index.fwx?area=09&cmd=servicios&id=3045&sub=9648, file "*Capacidad por Fuente 1999-2007"*, accessed on June 2008;

[15] Source: "*Generacion de Energia Electrica 1998 – 2007*", available at: http://www.aresep.go.cr/cgi-bin/index.fwx?area=09&cmd=servicios&id=3045&sub=9648, file "*Generación por Fuente 1999-2007"*accessed on June 2008.

[16] Source: Calculated using ARESEP data above.

the asset for the lifetime of the concession[17]. Up to now only PEG and three other generation plants have been developed under this structure,[18], one of those being the El General hydro power plant (which is pursuing the CDM status[19]), the second is La Joya hydro power plant (registered as CDM project[20]) and the third one the Miravalles III, a geothermal power plant that was commissioned in the year 2000. It is also important to know that both, the IPP, as well as the BOT scheme imply that 35% of the equity ownership must be owned by Costa Rican Nationals[21]. These facts and numbers illustrate that private investors and capital markets so far have faced difficulties to finance and operate energy generation assets in Costa Rica and that any entrants face increased real and perceived risks and barriers that will limit or turn unattractive the financing from capital markets. This is especially true if the Costa Rica specific Country and Regulatory Risk is combined with the technologic risk of an emerging technology like wind that has low participation in this specific market.

The fact that international equity markets are not capable or willing to finance investments in Costa Rica is also referenced in the literature:

Vivian O. Okere (2007)[22] defines Costa Rica as a Frontier Market, and clarifies: "*The International Finance Corporation (IFC) describes frontier markets are those emerging markets considered very risky when compared to the transitional emerging markets of Brazil, Russia, India and China (BRIC) and other climbing markets of Argentina, Taiwan, South Korea, Malaysia and Mexico etc. Many foreign investors prefer not invest in frontier markets such as Pakistan, Senegal, Nigeria, Nepal, Costa Rica, Maldives etc because of the risk involved. Limited stock market information and the problem of data availability are chronic in these markets.*"

Further, according to a recent report of the World Bank[23] (page 6) Costa Rica is ranked 117 out of 180 countries in terms of business climate and the most severe shortcomings were related to (page 10,11) anti-competitive and informal practices, lack of access and high cost of financing, as well as regulatory uncertainty. Specific emphasis is given to the lack of access and cost of financing, which is seen as one of the main limitations (page 5, 10, 11) and as a very severe constraint. Specifically the electricity sector is defined as financially and

[17] For a description of the legal framework please refer to KPMG, Investment in Costa Rica, 2005, available from http://www.kca.kpmg.com/dbfetch/52616e646f6d4956978197411d2a7bf8b12b48c7218269eb75721a1a2f857fd1/costarica.pdf, accessed on February 2010.

[18] Informe de operación anual 2008, CENTRO NACIONAL DE CONTROL DE ENERGÍA

[19] http://cdm.unfccc.int/Projects/Validation/DB/CS0ARNFFUC8XAFJZQGGJLM22VR46JZ/view.html, accessed on 8 February 2010.

[20] http://www.electricamatamoros.com/CentralLaJoya.aspx and http://cdm.unfccc.int/Projects/DB/AENOR1154424472.86/view, accessed on 8 February 2010.

[21] Law no. 7508 available at: http://www.aresep.go.cr/docs/Ley%20Generacion%20Electrica%20Autonoma%20o%20Paralela.pdf, accessed on 8 February 2010.

[22] Source: Journal of International Business and Economics , Jan, 2007 by Vivian O. Okere, available at: http://findarticles.com/p/articles/mi_6775/is_1_7/ai_n28522791/, accessed 8 February 2010.

[23] World Bank Report No. AAA39 – CR; Costa Rica Competitiveness Diagnosis and Recommendations, Volume 1, July 1, 2009

technically unsustainable due to lack of investments (page 19) and the prevailing regulations are complex and lack clarity.

Another reference that illustrates that the situation stems also from the World Bank[24] who already pointed out in 2004 that the need to increase the private share in the electricity sector is an urgent priority for Costa Rica.

The citations show that obtaining capital in the international market for investments in Costa Rica is not straight forward.

Result: There is strong indication that this criterion is fulfilled and thefore the presence of an investment barrier is confirmed.

ii) To further support the difficulty to finance energy projects in Costa Rica as explained in the above item and to prove that CDM helped to overcome the investment barrier, it is important to revise the history of PEG, its origination, preparation and the steps for financing of the activities conducted by the Project Developer. The information provided below is evidenced in the Econergy IPO Admission Document (IPO Document).[25]

The Project Developer, Econergy, was founded in 1994 in the US, initially as a clean energy consulting company. In 2001, Econergy started developing for third parties' greenhouse gas emission reduction projects under the emerging Clean Development Mechanim. In July 2003, Econergy developed and submitted the world's first CDM methodology to the UNFCCC (NM0001), which was approved in December 2003 (IPO Document, page 14). During the following years the company worked as a consultant for several CDM projects. Based on this track record and experience, Econergy seeked funds to finance its evolution from a consulting company into an investor in clean energy and carbon credit projects.

On 2nd September 2005, Econergy signed a CER loan agreement to obtain 4 million US$. This loan did not allow repayment in cash and it required the delivery of 1.103.000 CERs, during the years 2006-2013 (IPO Document, page 73). Consequently the loan must be seen as an up-front financing for all activities to be implemented by Econergy as a clean energy and carbon credit project developer. Furthermore, the use of the funds was limited to "... *purchase Certified Emission Reductions ("CERS"or carbon credits) and/or to invest in power generation projects which may be or can become Clean Development Projects ("CDM") projects...*". In line with this condition and the strategy of Econergy, this funding was used to develop a portfolio of investment opportunities with CDM potential in the clean energy sector.

According to the Guidelines for the Assessment of Barriers (Guildeline 6, Example 2) it is defined that: "For the cases where it can be objectively demonstrated that a significant part of the project investment is provided upfront by a company as a pre-payment for expected CERs, there is an objective demonstration that the CDM actually enabled the financing of the project."

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[24] Memorandum of the President of the International Bank for Reconstruction and Development to the Executive Directors on a Country Partnership Strategy for the Republic of Costa Rica, World Bank, April 2004.

[25] http://web.archive.org/web/20060602205507/www.econergy.com/investor_relations/admissions_document/Econergy_Admissions_Document.pdf, accessed on 8 February 2010.

Result: Given the fact that this financing was crucial for the development of the Econergy business model and its IPO that allowed the investment in PEG, there is an objective demonstration that the CDM actually enabled the financing of the project.

iii) To further prove that CDM was crucial to secure full financing for PEG, it is important to acknowledge that Econergy prepared the IPO to raise sufficient equity to develop its project pipeline, which included PEG (under the name of "Guayabo"). The CDM potential was clearly described in the IPO Document [page 17]. This IPO proposed explicitly to the investors that over 90% of the net proceeds of the IPO "*will be used to make direct equity investments in clean energy assets in emerging markets, with initial emphasis on Latin America and the Caribbean (LAC"). These have the potential to generate a dual revenue stream from the sales of both energy and Carbon Credits."*

With this proposal Econergy was successfully listed on February 23rd 2006, and obtained net IPO proceeds of £55.5 million to finance the proposed business plan. Given Econergy's track record and the importance given in the IPO Document to the benefit "*from an increasing demand for carbon credits"* (IPO Document, page 9), it is obvious that CDM was a crucial argument to raise the capital required for PEG.

Result: In line with the requirement of the Guidelines for Assessment of Barriers it is shown that "financing of the project was assured only due to the benefit of the CDM." and there is an objective demonstration that the CDM actually enabled the financing of the project.

(c) Also the Guidelines for Assessment of Barriers (Guideline 2, Example 2) defines that barriers can be shown when "the expected revenues from the CDM are significant when put into relation with the risk(s) caused by the barrier(s)".

i) In addition to the investment barriers cited above, there is another specific barrier due to the currency fluctuations. The cost of the WECs is in Euros and the functional currency of the PEG investment is the US Dollar. According to the Guidelines for Assessment of Barriers, it is defined that "*Project proponents (PPs) can make an argument that additional CDM revenues have helped overcome the increased risk associated with the barrier. For this, they have to transparently demonstrate that the expected revenues from the CDM are significant when put into relation with the risk(s) caused by the barrier(s) and/or total cost of the project.*"

The importance of the CERs as hedge agains currency fluctuations was already mentioned in the IPO Document [page 26]: *"The Directors believe that Econergy is able to effectively mitigate against long-term foreign currency risk for the following reasons: Carbon Credits from Econergy's projects are likely to always be sold in Euros or USD."*

The effectivity of this strategy is cleary shown in the case of PEG. The signature of a WEC purchase agreement with a value of € 48.07 million generated a significant currency exposure for PEG. The fact that the CER revenues are the project's only receivable quoted in Euro, make them a valuable hedge against this exposure. As a matter of fact the total CER revenue during 10 years, if quoted at € 12 per CER as referenced by respective purchase proposals[26], could provide total revenue of € 11.2 million. This revenue partially offsets the currency fluctuations of the loan and could compensate a deterioration of the US Dollar versus the Euro by about 23%.

Result: In line with the requirement of the Guidelines for Assessment of Barriers it can be shown that "the expected revenues from the CDM are significant when put into relation with the risk(s) caused by the barrier(s)". As the compensation provided by the CERs is significant when compared to the exchange risk, the presence of the specific barrier is confirmed.

Sub-step 3b. Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed project activity):

As it has been shown above, there are clear investment barriers for *Alternative 1: The proposed project activity - construction of a new wind energy development with an installed capacity of 49.50 MW - not undertaken as a CDM project*.

In contrast, the *Alternative 2: Continuation of the current situation (no project activity or other alternatives undertaken)* is not hindered by any of the barriers mentioned. In fact, the installation of prompt start power stations, a well-established technology in Costa Rica can be observed during the validation process of this project, as ICE is renting thermal power generation units to supply electricity for Costa Rican demand.[27]

Based on the definitions of the Additionality Tool, it can be concluded that the barriers identified i) "effectively prevent potential project proponents from carrying out the proposed project activity undertaken without being registered as a CDM project activity", and ii) "do not prevent the implementation of at least one of the alternatives", as defined by the Additionality Tool.

Consequently both Sub-steps 3a-3b are satisfied and we proceed to Step 4.

Sub 4. Common practice analysis:

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

In accordance with the "Tool for the demonstration and assessment of additionality", projects are considered similar to the project activity 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, acess to technology, access to financing, etc.

Currently, there are four wind farms operating in Costa Rica. These activities and their respective nominal capacity and operation starting date are demonstrated in the Table below. These four projects represent

[26] BNPP LOI, 9 July 2007.

[27] http://www.nacion.com/ln_ee/2008/enero/12/pais1382249.html, accessed on 8 February 2010.

around 3% of the electricity generation in the country[28]. This indicates that, despite the good wind potential in the country, the development of wind farms is not a common practice in Costa Rica. Three of the wind farms have been implemented as Activities Implemented Jointly under the Pilot Phase[29] (Aeroenergía, Tilarán and Tierras Morenas). As such they followed the specific purpouse of Annex I parties to develop emission reduction projects in other countries and had access to non commercial finance conditions and grants. Specifically the Tillarán project also had a wind turbine manufacturer (Kenentech) as shareholder and thefore preferential acccess to the technology.
Another specific feature of the mentioned windfarms is that they are all privately owned, which is allowed for assets up to and including 20 MW of installed capacity.

In contrast to the plants mentioned above, the Tejona Windfarm Project is owned by the state company ICE, was the only commissioned after 2000 and was structured as a CDM project activity, being registered in May 2007.

Table 12. List of Operating Wind Farms in Costa Rica

Wind Farm	Nominal Capacity	Operation Starting Date	Equity Investors that developed the project	Non commercial Financial support or Mechanism
Tilarán[30]	20 MW	1996	- Plantas Eólicas S.A. (joint venture between Merril International, US and Charter Oak Energy, subsidiary of Northeas Utilities, both US) - Kenetech Windpower, US[3132]	AIJ
Aeroenergía[33]	6 MW	1998	- Aeroenergía S.A., CR - Energy Works (subsidiary of US based Bechtel Corp.) - Power Systems Inc., US - Bluefields international, US - Micon A/S, Denmark[34]	AIJ
Tierras Morenas[35]	20 MW	1999	- New World Power Corp., US - Molinas de Viento del Arenal S.A., Costa Rica	AIJ / Commonwealth Development

[28] Calculated using data from ICE and ARESEP: "*Capacidad Instalada del sector electrico nacional 1999-2007*" and "*Generacion de Energia Electrica 1998-2007*". References to these documents presented in footnotes 15 and 16.

[29] Activities Implemented Jointly (AIJ) represent a pilot phase of CDM and Joint Implementation based on the concept of "learn-by-doing" where Annex-I Parties implement emission reductions activities in other countries. AIJ are based on the development of 'small-scale' projects with intensive financial aid from international organizations and/or Annex-I countries.

[30]Source: http://unfccc.int/kyoto_mechanisms/aij/activities_implemented_jointly/items/1722.php, accessed on February 2010.

[31]Source: http://opus.zbw-kiel.de/volltexte/2003/1083/pdf/toc-dcp-1997-49.pdf, accessed 8 February 2010.

[32] Barrier faced by Tilaran: Note that Kenetech Windpower filed for bankruptcy during 1996. This was followed by various company restructurations regarding Plantas Eolicas SA. which is now part of MesoAmerica Energy (http://www.mesoamericaenergy.com/). This indicates another investment barrier based on previous negative experiences with Wind Energy invstments in Costa Rica.

[33] Source: http://unfccc.int/kyoto_mechanisms/aij/activities_implemented_jointly/items/1724.php, accessed on June 2008.

[34]Source: http://opus.zbw-kiel.de/volltexte/2003/1083/pdf/toc-dcp-1997-49.pdf, accessed on 8 February 2010.

[35] Source: http://unfccc.int/kyoto_mechanisms/aij/activities_implemented_jointly/items/1728.php, accessed on June 2008.

			- MINAE (CR Ministry for Environment and Energy)[36]	Corporation (CDC) and International Finance Corporation (IFC)
Tejona windfarm[37]	20 MW	2002	Electricity Institute of Costa Rica (Instituto Costaricense de Electricidad - ICE)	CDM, registered in May 2007

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

There are distinctions between the proposed project activity and similar projects implemented previously or currently underway in Costa Rica.

In accordance with the Sub-step 4a of the Tool, any similar activity developed as a CDM project activity is not to be included in the Common Practice Analysis. Under this circumstance, Tejona windfarm is excluded for further analysis.

In addition, as previously stated and in accordance with the Additionality Tool, projects are considered similar if they have a similar scale and have been developed in a comparable environment with respect to investment climate, access to financing, among others. Aeroenergía and Tierras Morenas and Tilarán have been developed as pilot AIJ Projects and received significant funding from international entities[38]. Consequently, these projects have been developed in a distinct investment context which contributed to the alleviation of the investment barriers, as outlined in Sub-step 3a.

Moreover, the three wind projects (Aeroenergía, Tilarán and Tierras Morenas) have a considerable different scale – at least the half nominal installed capacity – when compared to PEG.

In addition, the mentioned projects are fully owned and operated by private investors while PEG is being developed under the BOT sheme. As a matter of fact there are only three other projects developed under this modality in Costa Rica, none of them using wind as energy source: Two of them are hydro power plants and are registered as CDM Projects (La Joya) or under validation (El General) and the third one is Miravalles III, a geothermal power plant, in operation since the year 2000.

Based on the evidence and arguments provided, it can be concluded that wind projects implemented previously or currently underway in Costa Rica, i) are of different scale, ii) have been developed under a different investment climate, iii) benefitted from differentiated access to technology and iv) financed by having access to non-commercial financing terms provided by development banks.

As a consequence, we can conclude in compliance with the Additionality Tool that, "similar activities are observed, but essential distinctions between the project activity and similar activities can reasponably be explained." Accordingly, the proposed project can not be considered common practice.

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[36]Source: http://opus.zbw-kiel.de/volltexte/2003/1083/pdf/toc-dcp-1997-49.pdf, accessed on 8 February 2010.

[37] Source: http://cdm.unfccc.int/Projects/DB/TUEV-SUED1166705222.75/view, accessed on June 2008.

[38] 70% of the necessary funding resources to develop Tierras Morenas Project was provided by Commonwealth Development Corporation ((CDC), UK), International Finance Corporation ((IFC), USA) and other commercial banks from USA and Europe. 75% of the the necessary funding resources to develop Aeroenergía was provided by Central America Economic Integration Bank ((CABEI), Costa Rica). Information on both projects can be obtained by accessing references provided at footnotes 5 and 7.

Therefore, Sub-steps 4a and 4b are satisfied and the proposed project activity is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

In order to calculate the ex-ante estimation of emission reductions for the first crediting period, estimated figures were used for parameters that are not available at validation or that will be monitored during the crediting period.

No potential emission sources of leakage and project emissions were identified for this project.

Project Emissions

$PEy = PE_{FF,y} + PE_{GP,y} + PE_{HP,y}$

Where:

PEy = Project emissions in year *y* (tCO_2e/yr);
PE_{FFy} = Project emissions from fossil fuel consumption in year y (tCO_2/yr);
$PE_{GP,y}$ = Project emissions from the operation of geothermal power plants due to the release of non-condenate gases in year y (tCO_2e/yr);
$PE_{HP,y}$ = Project emissions from water reservoirs of hydro power plants in year y (tCO_2e/yr);

PEG is a wind power plant, without fossil fuel consumption. Consequently, $PE_{FF,y} = 0$ (no fossil fuel consumption), $PE_{GP,y} = 0$ (this project is not a geothermal power plant) and $PE_{HP,y} = 0$ (this project is not a hydro power plant).

Baseline emissions

Baseline emissions include only CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity. The methodology assumes that all project electricity generation above baseline levels would have been generated by existing grid-connected power plants and the addition of new grid-connected power plants. The baseline emissions are to be calculated as follows:

$BE_y = EG_{PJ,y} \cdot EF_{grid,CM,y}$

Where:

BE_y = Baseline emissions in year *y* (tCO_2/yr);
$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year *y* (MWh/yr);
$EF_{grid,CM,y}$ = Combined margin CO_2 emission factor for grid connected power generation in year *y* calculated using the latest version of the "Tool to calculate the emission factor for an electricity system" (tCO_2/MWh);

The calculation of $EG_{PJ,y}$ is different for (a) Greenfield plants, (b) retrofits and replacements, and (c) capacity additions. PEG is a Greenfield plant; consequently option (a) will be used:

(a) Greenfield renewable energy power plants

If the project activity is the installation of a grid-connected renewable power plant/unit at a site where no renewable power plant was operated prior to the implementation of the project activity, then:

$EG_{PJ,y} = EG_{facility,y}$

Where:

$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year *y* (MWh/yr);
$EG_{facility,y}$ = Quantity of net electricity generation supplied by the project plant/unit to the grid in the year *y* (MWh/yr)

Leakage

No leakage emissions are considered. The main emissions potentially giving rise to leakage in the context of electric sector projects are emissions arising due to activities such as power plant construction and upstream emissions from fossil fuel use (e.g. extraction processing, transport). These emissions sources are neglected.

Emission reductions

Emission reductions are calculated as follows:

$ER_y = BE_y – PE_y$

Where:
ER_y = Emission reductions in year y (tCO_2e/yr);
BE_y = Baseline emissions in year y (tCO_2/yr);
PE_y = Project emissions in year y (tCO_2e/yr);

As $PE_y = 0$, the emission reductions will be calculated as:

$ER_y = BE_y$

$BE_y = EG_{PJ,y} \cdot EF_{grid,CM,y}$

The baseline emission factor ($EF_{grid,CM,y}$) is calculated as a combined margin (CM), consisting of the combination of operating margin (OM) and build margin (BM) factors. Calculations for this combined margin were based on data from an official source and made publicly available.

According to the “Tool to calculate the emission factor for an electricity system” version 02, power plant capacity additions registered as CDM project activities should be included in the sample group that is used to calculate the operating margin if applicable, but excluded from the sample group m, used to calculate the build margin.

STEP 1. Identify the relevant electricity systems

For the purpose of determining the electricity emission factor, a project electricity system is defined by the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity and that can be dispatched without significant transmission constraints.

In the case of PEG project, the connected grid is the National Interconnected System (*NIS – Sistema Nacional Interconectado*) and all connected power plants (without significant transmission contraints) are included in the project boundary.

At the moment, the DNA has not published a delineation of the project electricity system.

STEP 2. Choose whether to include off-grid power plants in the project electricity system

Only grid power plants are included in the calculation, Option I.

STEP 3. Select an operating margin (OM) method

The method used to calculate the operating margin emission factor ($EF_{grid,OM,y}$) was the Simple adjusted OM method (b). The data vintage used was the ex ante option, where a 3 year generation weighted average based on the most recent data available (2005, 2006 and 2007), without the requirement to monitor and recalculate the emissions factor during the crediting period.

In this calculation the CDM project activities are included in the sample group used to calculate the operating margin, if the criteria for including the power source in the sample group apply.

STEP 4. Calculate the operating margin emission factor according to the selected method

The power plants/units are separated in low-cost/must-run power sources (k) and other power sources (j). This is calculated based on data on fuel consumption and net electricity generation.

$$EF_{grid,OM-adj,y} = (1-\lambda_y) \times \frac{\sum_m EG_{m,y} \times EF_{EF,m,y}}{\sum_m EG_{m,y}} + \lambda_y \times \frac{\sum_k EG_{k,y} \times EF_{EL,k,y}}{\sum_k EG_{k,y}}$$

Where:

$EF_{grid,OM-adj,y}$ = Simple adjusted operating margin CO_2 emission factor in year y (tCO2/MWh);

λ_y = factor expressing the percentage of time when low-cost/must run power units are on the margin in year *y*;

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh);

$EG_{k,y}$ = Net quantity of electricity generated and delivered to the grid by power unit *k* in year *y* (MWh);

m = All grid power units serving the grid in year y except low-cost/must-run power units

k = all low-cost/must run grid power units serving the grid in year y;

y = The relevant year as per the data vintage chosen in Step 3

The parameter λ_y is defined as follows:

$$\lambda_y (\%) = \frac{\text{Number of hours low-cost/must-run sources are on the margin in year y}}{\text{8760 hours per year}}$$

It is assumed that all the low-cost/must-run plants produce zero net emissions.

STEP 5. Identify the group of power units to be included in the build margin

The idenfied power plants are listed in Annex 3, Table. 3 .

It is important to emphasize that according to the "Tool to calculate the emission factor for an electricity system", power plants registered as CDM project activities are excluded from the sample group m. For this crediting period, the Build Margin is calculated ex-ante, using Option 1.

Option 1: For the first crediting period, calculate the build margin emission factor ex-ante, based on most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation.

STEP 6. Calculate the build margin emission factor

The build margin emission factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units m during the most recent year y for which power generation data is available, calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

$EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year y (tCO_2/MWh);
$EG_{m,y}$ = Net quantity fo electricity generated and delivered to the grid by power unit m in year y (MWh)
$EF_{EL,m,y}$ = CO_2 emission factor of power unit m in year y (tCO_2/MWh);
m = Power units included in the build margin
y = Most recent historical year for which power generation data is available

STEP 7. Calculate the combined margin emissions factor

The combined margin emission factor was calculated as the weighted average of the Operating Margin emission factor ($EF_{grid,OM,y}$) and the Build Margin emission factor ($EF_{grid,BM,y}$):

$$EF_{grid,CM,y} = w_{OM} \times EF_{grid,OM,y} + w_{BM} \times EF_{grid,BM,y}$$

For wind and solar projects, the default weights are as follows: w_{OM} = 0.75 and w_{BM} = 0.25 (owing to their intermittent and non-dispatchable nature). So, these abovementioned weights were used for this project activity.

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

Data / Parameter:	$EF_{grid,CM,2005-2007}$
Data unit:	tCO_2 / MWh
Description:	Combined margin CO_2 emission factor of the Costa Rican grid in year 2005,

	2006 and 2007 using the latest version of the "Tool to calculate the emission factor for an electricity system"
Source of data used:	Calculated
Value applied:	0.3882
Justification of the choice of data or description of measurement methods and procedures actually applied :	This data will be archived electronically and according to internal procedures, until 2 years after the end of the crediting period.
Any comment:	Calculated as weighted sum of the OM and BM emission factors, as explained in section B.6.3.

B.6.3 Ex-ante calculation of emission reductions:

In order to calculate the ex-ante estimation of emission reductions for the first crediting period, estimated figures were used for parameters that are not available at validation or that will be monitored during the crediting period.

$$ER_y = BE_y$$

$BE_{,y}= 245{,}300 \times 0.3882$

The baseline emission factor ($EF_{grid,CM,y}$) is calculated as a combined margin (CM), consisting of the combination of operating margin (OM) and build margin (BM) factors. Calculations for this combined margin were based on data from an official source and made publicly available.

According to the "Tool to calculate the emission factor for an electricity system" version 01, power plant capacity additions registered as CDM project activities should be included in the sample groub that is used to calculate the operating margin if applicable, but excluded from the sample group m, used to calculate the build margin.

STEP 1. Identify the relevant electricity system

For the purpose of determining the electricity emission factor, a project electricity system is defined by the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity.

In the case of PEG project, the connected grid is the National Interconnected System (*NIS – Sistema Nacional Interconectado*) and all connected power plants (without significant transmission contraints) are included in the project boundary.

STEP 2. Choose whether to include off-grid power plants in the project electricity system

Only grid power plants are included in the calculation.

STEP 3. Select an operating margin (OM) method

The method used to calculate the operating margin emission factor ($EF_{grid,OM,y}$) was the Simple adjusted OM method (b). The data vintage used was the ex ante option, where a 3 year generation weighted average based on the most recent data available (2005, 2006 and 2007), without the requirement to monitor and recalculate the emissions factor during the crediting period.

In this calculation the CDM project activities are included in the sample group used to calculate the operating margin, if the criteria for including the power source in the sample group apply.

STEP 4. Calculate the operating margin emission factor according to the selected method

As can be observed in Annex 3, Lambda values used to calculate the operating margin emission factor have been estimated as follows:

$\lambda_{2007} = 0.3933$
$\lambda_{2006} = 0.4784$
$\lambda_{2005} = 0.5674$

The $\mathbf{EF_{grid,OM\text{-}adj,\ 2005,2006,2007}} = 0.4850\ tCO_2/MWh$.

STEP 5. Identify the group of power units to be included in the build margin

The idenfied power plants are listed in Annex 3, Table. 3 .

It is important to emphasize that according to the "Tool to calculate the emission factor for an electricity system", power plants registered as CDM project activities are excluded from the sample group m. For this crediting period, the Build Margin is calculated ex-ante, using Option 1.

Option 1: For the first crediting period, calculate the build margin emission factor ex-ante, based on most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation.

STEP 6. Calculate the build margin emission factor

The build margin emissions factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units m during the most recent year y for which power generation data is available, calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

$$EF_{grid,BM,2007} = 0.0976$$

STEP 7. Calculate the combined margin emissions factor

The combined margin emission factor was calculated as the weighted average of the Operating Margin emission factor ($EF_{grid,OM,y}$) and the Build Margin emission factor ($EF_{grid,BM,y}$):

$$EF_{grid,CM,y} = w_{OM} \times EF_{grid,OM,y} + w_{BM} \times EF_{grid,BM,y}$$

For wind and solar projects, the default weights are as follows: w_{OM} = 0.75 and w_{BM} = 0.25 (owing to their intermittent and non-dispatchable nature). So, these abovementioned weights were used for this project activity.

The $EF_{grid,CM,2005,2006,2007}$ = 0.75 x 0.4850 + 0.25 x 0.0976 = 0.3882 tCO_2/MWh

Therefore, for the first crediting period, the emission reductions will be calculated as follows:

$\mathbf{ER_y = 0.3882 * EG_{PJ,y}}$ (in tCO_2e)

$\mathbf{EG_{PJ,y} = 245{,}300}$

$\mathbf{ER_y = 95{,}225}$

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

Year	Estimation of project activity emission (tonnes of CO2e)	Estimation of baseline emission (tonnes of CO2e)	Estimation of leakage (tonnes of CO2e)	Estimation of overall emission reductions (tonnes of CO2e)
2011	0	87,290	0	87,290
2012	0	95,225	0	95,225
2013	0	95,225	0	95,225
2014	0	95,225	0	95,225
2015	0	95,225	0	95,225
2016	0	95,225	0	95,225
2017	0	95,225	0	95,225
2018	0	95,225	0	95,225
2019	0	95,225	0	95,225
2020	0	95,225	0	95,225
2021	0	7,935	0	7,935
Total (tonnes of CO2e)	**0**	**952,250**	**0**	**952,250**

*from 1 February 2011 to 31 January 2021

B.7 Application of the monitoring methodology and description of the monitoring plan:

All data collected in purpose of monitoring will be archived electronically and be kept for at least 2 years after the end of the crediting period. It is important to highlight that all measurements will be done with calibrated equipment, according to relevant industry standards.

B.7.1 Data and parameters monitored:

Data / Parameter:	**$EG_{PJ,y}$**
Data unit:	MWh
Description:	Electricity supplied by the project activity to the grid
Source of data to be used:	Measured continuously at the PEG substation and aggregated in hourly basis
Value of data applied for the purpose of calculating expected emission reductions in section B.5	For the first phase: 92,646 MWh For the second phase: 245,300 MWh (when fully operational)
Description of measurement methods and procedures to be applied:	Directly measured during the crediting period. This data will be archived electronically and according to internal procedures, until 2 years after the end of the crediting period.
QA/QC procedures to be applied:	This data will be directly used for calculation of emission reductions. Records of sales to the grid (invoices) will be used to ensure the consistency and will be cross-checked on a monthly basis. The project will have a meter installed that will be provided by the ICE, calibrated by a specialized laboratory and certified by *Autoridad Reguladora de los Servicios Publicos* - ARESEP.
Any comment:	-

B.7.2 Description of the monitoring plan:

1. Management Structure and Responsibility

Overall responsibility for daily monitoring and reporting lies with the project owner. A staff will be defined within the owner company to carry out the monitoring work (data recording and archiving, quality assurance and quality control of the data, equipment’s calibration, scheduled and unscheduled maintenances and adoption of corrective actions, if needed).

1.1 Management Structure

The manager of the proposed project will hold the overall responsibility for the monitoring process, including the follow-up of daily operations, definition of personel involved with the monitoring work, revision of the monitored results/data, and quality assurance of measurements and the process of training new staff.

1.2 Responsibility of the personnel directly involved:

The personnel involved with monitoring will be responsible for carrying out the following tasks:

- Supervise and verify metering and recording: the staff will coordinate internally with other departments to ensure and verify adequate metering and recording of data, including power delivered to the grid.
- Collection of additional data, sales/invoices: the staff will collect sales receipts and relevant data for monitoring of the project activity;
- Calibration: the staff will coordinate internally to ensure that calibration of the metering instruments is carried out in accordance with regulations of ARESEP and ICE.
- Data Archives: the staff will be responsible for keeping all monitoring data, and making it available to the DOE for the verification of the emission reductions.

1.3 Support and Third Parties Participation:

The staff will receive support from the CDM consultants / experts (internal and/or external) in his responsibilities through the following actions:

- Provide the staff with a calculation template in electronic form for calculation of annual emission reductions;
- Provide a specific CDM monitoring training to the personnel involved in the project's operation;
- Follow-up of the monitoring plan and continuous advice to the staff ;
- Compilation of the monitored data and preparation of the monitoring report;
- Review of monitoring reports;
- Coordination with DOEs for the preparation of periodical verifications.

2. Data Recording and Archiving

Measurements of the energy generated and provided to the grid will be electronically monitored and stored through the use of a Supervisory Control and Data Acquisition (SCADA). This system is used for data acquisition, remote monitoring, open-loop and closed-loop control for both individual wind turbines and the wind farm. It enables the project staff to monitor the operating state in a real time basis and to analyse saved operating data. Data monitored by this system will be kept legible, dated, and readily identifiable and be made accessible for audit purposes either in electronic files or physical documents.

Other physical document such as invoices, paper-based maps, diagrams and other relevant monitoring requirements will be collected and stored in a central place, together with this monitoring plan. In order to facilitate auditors' reference of relevant literature relating to the project, the project material and monitoring results will be indexed. All electronical and paper-based information will be stored by the project owner and kept at least for 2 years after the end of the crediting period.

3. Quality Assurance and Quality Control

Accuracy patterns of the meters used at the project site are defined at the PPA. According to this agreement, meters used shall have an accuracy of equal to or higher than 0.2s (Class 0.2) and be periodically calibrated as per national calibration standards. The project owner will keep a back-up meter installed that can be accessed in case of mal-functioning of the main meter. In addition, the PPA also authorizes the installation of an additional meter for cross-checking purposes. The need of this additional meter will be adequately assessed by the project owner during the crediting period.

The data generated will be analysed daily by the operational personnel and reviewed by the project manager on a monthly basis. In order to guarantee the accuracy of the data measured and used for calculating emission reductions, project developer will cross-check this information with the amount of energy stated at the energy sales receipts (invoices), provided by ICE.

If required, other quality assurance and quality control relevant procedures will be developed by the project owner.

Electricity generation of the project will be monitored through the use of onsite metering equipments at the project site; a main meter will be installed after the main transformer in the sub-station (Mogote substation) to monitor the net electricity supplied to the grid. The meter is calibrated by ARESEP, the national regulating entity in Costa Rica, and a procedure for calibration and validation is provided for in the PPA.

4. Periodical Maintenance and Calibration of Equipments

Periodical maintenance inspections will be conducted by the operation personnel. According to the PPA, an annual maintenance plan shall be elaborated and submitted to ICE for approval. The Program shall describe the frequency of scheduled maintenance inspections and activities carried out to assure a proper performance of the Project Activity. Unscheduled maintenance activities may also be performed as a way to remedy any fault, defect, breakdown, deficiency and failure of the WECs and other related systems. If the need is identified, preventive actions will be undertaken by the project owner as a way to guarantee the energy supply as per defined at the PPA. Furthermore, corrective actions will also be defined and adopted if a problem is identified during both scheduled and unscheduled maintenance activities. Records of the periodical maintenance inspections will be kept by the project owner and be made available for ICE technicians and external auditors.

As previously stated, the metering equipment will be properly configured and checked periodically according to the requirements from *ARESEP* Regulations and the PPA with ICE. A start-up configuration and checking of metering equipments is also expected to occur before project activity's commercial operation.

Should any previous months reading of the main meter be inaccurate by more than the allowable error, or otherwise, functioned improperly, the electricity generated by the proposed project shall be determined by:

1) first, by checking the data from Backup system, unless a test by either party reveals it is inaccurate;
2) if the backup system is not with acceptable limits of accuracy or is otherwise performing improperly the proposed project owner and the electric power company shall jointly prepare an estimate of the correct reading; and
3) If the proposed project owner and the electric power company fail to agree on the estimate of the correct reading, then the matter will be referred for arbitration according to agreed procedures.

5. Verification and Monitoring Results

The verification of the monitoring results of the project is a mandatory process required for all CDM projects. The main objective of the verification is to independently verify that the project has achieved the emission reductions as reported and projected in the PDD.

The responsibilities for verification of the projects are as follows:

- Sign a verification service agreement with specific DOE and agree to a time framework for carrying out verification activities. The proposed project owner will make the arrangements for the verification and will prepare for the audit and verification process to the best of its abilities.
- The proposed project owner will facilitate the verification through providing the DOE with all required necessary information, before, during and, in the event of queries, after the verification.
- The proposed project owner will fully cooperate with the DOE and instruct its staff and management to be available for interviews and respond honestly to all questions from the DOE.

The verification audits will be based on the requirements of the latest version of the VVM.

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)

The date of completion the application of the methodology to the project activity study is 24/06/2008.

The person/entity determining the baseline is as follows:
Econergy Brasil Ltda, São Paulo, Brazil
Telephone: +55 (11) 3555-5700
Contact person: Mr. Maurício Bencic Rovea
e-mail: mauricio.rovea@econergy.com.br

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:

17/07/2007 – Date of the contract agreement for purchase the Wind Energy Converters.

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

18 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:

Not applicable.

C.2.1.2. Length of the first crediting period:

Not applicable.

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

01/02/2011 or on the date of registration of the CDM project activity, whichever is later.

C.2.2.2. Length:

10 years.

SECTION D. Environmental impacts

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

Guanacaste Wind Farm has completed an Environmental Impact Assessment (EIA) that is required by Costa Rica's environmental law. The EIA for the project activity was submitted to SETENA - *Secretaria Técnica Nacional Ambiental*, the Environmental National Technical Secretary and was approved by the Resolution 2028 in October 2007. This document was completed by the consultancy firm "*Gestión Ambiental de Proyectos* (GAPRO, S.A.)" and provides a comprehensive analysis of the proposed project, and anticipates environmental, economic and social impacts (positive and negative) on the region and people in the area as outlined at the table below.

Table 13. Environmental Impacts and Mitigation Measures Proposed

Identified environmental impacts	Conclusions and Measures taken
Physical and Biotic Impacts	
Air Pollution and Atmospheric Emissions	
Construction Phase The main impacts in the air refer to dust generation and atmospheric emissions caused by earth works (excavations) to adapt internal routes and paths and to settle aero-generators and transmission cables; traffic of heavy and light vehicles to transport construction material and the production of cement.	Impacts are considered irrelevant or moderate. Measures comprise: i) to assure a good maintenance of heavy and light vehicles used; ii) to monitor vehicles and other machines used; iii) to splash water during excavation to avoid dust expansion iv) to replace the removed land in the project site.
Operational Phase No impacts on air quality are observed for this phase.	-----
Impacts on Biodiversity and Ecosystems	
Construction Phase Suppression of vegetation in limited areas to adapt internal routes and paths; impacts over animal life dependent on the existent vegetation and also the transportation of construction materials that could possibly disturb animal life in directly affected areas.	All impacts are classified as moderate. Measures comprise: i) to assure that only a small quantity of trees will be suppressed; ii) to develop a plan to accelerate the natural sprouting of pasture area (that will be not impacted during construction).
Operational Phase Most important impact is related to the mortality of birds during the operation of aero-generators.	Project site is not a common route for birds. Nevertheless, the mortality of birds will be continuously monitored and reported.

Impacts on Soil	
Construction Phase Impacts on soil relate to the adaptation of project's internal ways and paths, construction of the sub-station, preparation of land to install the aero-generators and excavations to introduce transmission cables.	All impacts have been considered moderate. Measures comprise: i) to control pluvial waters in areas considered of high erosion risk (such as the land where the aero-generators will be installed); ii) to prevent sediments dragging by installing protection collectors in these areas; iii) land that is extracted will be deposit in a discharge area to be used or applied onsite.
Operational Phase No impacts on air quality are observed for this phase.	-----
Impacts on Superficial and Subterranean Waters	
Construction Phase Contamination of water courses through possible spilling of fossil fuel or other sediments during the use of cranes to install the aero-generators, transportation of material for construction, excavations and earth works and the generation of effluents from cement production.	Impacts have been classified as irrelevant or moderate. Measures include: i) to ensure good maintenance of vehicles; ii) construction of narrow channels and collection wells to avoid that contaminants reach water courses; iii) fuel for the crane and other heavy machinery will be stored onsite in a metallic container to avoid contact with rain and any kind of contamination of water courses.
Operational Phase Contamination of subterranean waters with fuel spilling during the operation of the sub-station.	Impact is considered moderate. Narrow channels and collection wells will be built to avoid contamination.
Social Impacts	
Construction Phase Increase of: i) traffic in the routes surrounding the project site; ii) foreign staff with different costumes and values (possible source of conflicts).	Impacts are considered moderate. Material transportation into the project site will be programmed and monitored in order to avoid intense traffic in the area. Project developer committed to hire local employees as a way to diminish this possible impact.

As a result of this assessment, the EIA concluded there will be no transboundary impacts related to the construction and operation of the PEG. The main impacts outlined in the EIA were considered temporary and, thus, not considered significant.

In addition, there will be many positive environmental impacts generated as a result of the project. Local jobs will be created during construction and then operation of the plant. Costa Rica will also benefit from having a new large-scale source of emissions-free renewable energy producing electricity for its citizens – helping to reduce GHG emissions and improve air quality.

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:

The EIA has established that the environmental impacts that will occur during the construction and operational phases will not be significant.

As stated in Section D.1, there will be no transboundary impacts resulting from the construction or operation of the PEG project. All the relevant impacts occur within Costa Rican borders and have been mitigated to comply with the environmental requirements for the project's implementation.

SECTION E. Stakeholders' comments

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

In accordance with the Costa Rican procedures to obtain the EIA approval, project proponents must present the project to local stakeholders (dated of 1 June 2007). The local stakeholder consultation that was conducted occurred in two phases. The first phase entailed a qualitative study and the other consisted of a quantitative study. The qualitative study entailed interviews with members of local and regional organizations located in the project's area. In addition to being informed about the proposed PEG wind project, stakeholders were asked to provide responses to a number of different issues, including economic and social issues they were facing in the area, perceptions of private electrity companies, opinions about renewable energy, the positive and negative impacts they could foresee by having a project like PEG developed in the region, as well as ideas about important community issues to consider when developing a project like PEG. The quantitative study consisted of interviews with 320 habitants that live in the indirect or direct project influence area.

E.2. Summary of the comments received:

All local stakeholders interviewed showed a high level of acceptance towards the development of the PEG project activity. Among comments received, there was specific and regular mention of the benefits of the jobs that will be directly and indirectly created by the project, increase in regional tourism and the reactivation of local business and services. The regional stakeholders also pointed to power generation by a renewable source as a favourable characteristic of this project.

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

As the local stakeholder consultation was done in small group interviews or in a single person interviews, all questions raised were collected and answered by PEG promptly. PEG appreciated all questions raised by the local stakeholders, and will actively work to ensure that the project will be in compliance with all applicable environmental regulation in Costa Rica, and that it maintains the support from local residents in the area.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

Not applicable.

Annex 3

BASELINE INFORMATION[39]

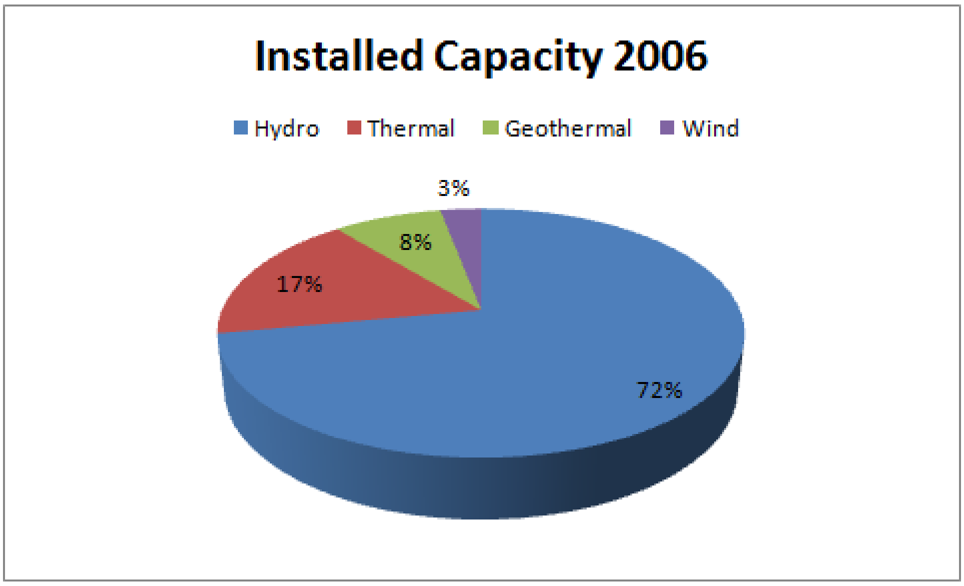
Table 1 gives an overview of the power plants that form the generation park (available at the moment of the PDD writing), as well as their characteristics. As demonstrated by this Table, the interconnected system has an effective installed capacity of 1,840 MW, 72% of these are hydroelectric power plants, 17% thermal power plants, 8% geothermal power plants and only 3% are wind power plants. From the total installed capacity, the national government, owned and controlled by ICE, operates 82%, the whole private power generation sector stands for around 11% and the distribution companies operate 7%.

[39] References: www.grupoice.com, www.aresep.go.cr and www.dse.go.cr

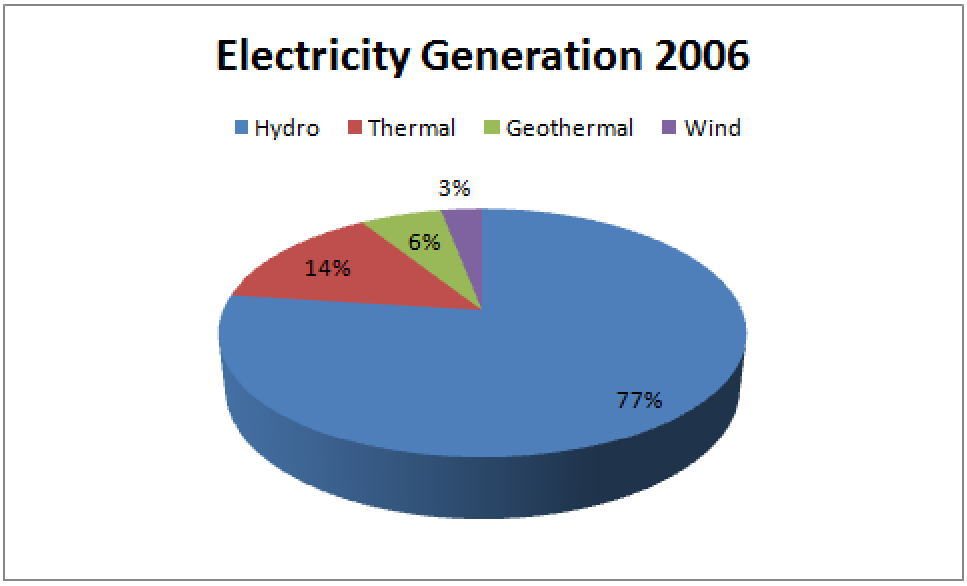
Name	Starting operational year	Efective installed capacity (MW)	Average annual generation (GWh)	% from the total NIS
1. Hydro Power Plants				
Arenal	1979	157.40	675	
Corobici-Dengo	1082	174.00	758	
Sandillal	1992	32.00	133	
Cachí	1967	105.00	617	
Garita	1958	40.40	172	
Menores ICE	Var.	5.32	39	
Río Macho	1963	120.00	577	
Ventanas Garita	1988	100.00	455	
Toro I	1996	24.00	95	
Toro II	1997	66.00	268	
Angostura	2000	180.00	819	
Peñas Blancas	2002	37.03	178	
Generación Privada	Var.	127.32	690	
CNFL	Var.	73.00	366	
ESPH	Var.	2.34	18	
JASEC	Var.	20.32	101	
Chocosuela (Coopel.)	1999	25.70	117	
Subtotal		1289.83	6078	**79.99%**
2. Thermal power plants				
Barranca	1974	36.00	28	
S.A.Gas	1973	34.00	22	
Colima	1956	14.00	24	
Moín Pistón	1977	26.00	21	
Moín Gas	1991/1995	130.50	193	
Moín CNFL	2002	78.00	48	
Río Azul	2004	3.70	-	
Ingenios (Taboga)	2003/2004	5.00	13	
Subtotal		327.20	349	**4.59%**
3. Geothermal power plants				
Miravalles I	1994	55.00	342	
Miravalles II	1998	55.00	350	
Boca de Pozo	1994	5.00	23	
Miravalles III (BOT)	2000	26.20	196	
Miravalles V	2003	15.50	-	
Subtotal		156.70	911	**11.99%**
4. Wind Power Plants				
Tejona	2002	20.00	81	
Eólico Privado	1998/2000	46.00	179	
Subtotal		66.00	260	**3.42%**
Total NIS		**1839.73**	**7598**	

Table. 1 - Generation system, Costa Rica, 2004

During the 2006 year, the National Electric System generated 8,641 GWh, increasing 5.2% in relation to the previous year. ICE is responsible for 93% of it, generating 75% by their own power plants and buying only 18% from independent power producers. The other 7% were generated by other distribution companies (owned by the government). From the total, 8730 GWh were produced inside Costa Rica while 89 GWh were imported.



Graph 3 - Costa Rica Installed Capacity in 2006



Graph 4 - Costa Rica Power Generation in 2006

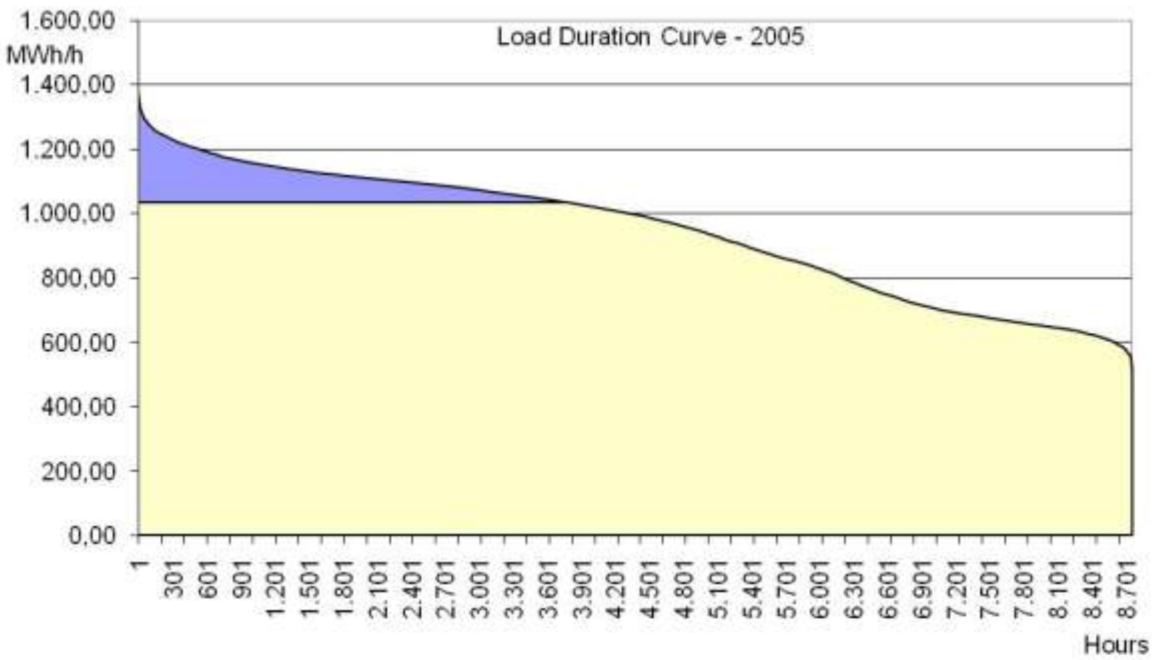
In terms of lambda factor calculation, the data was provided by ICE with the most recent information available. The Emission Factor was calculated ex-ante with data from years 2005, 2006 and 2007.

On the following pages, a summary of the analysis is provided. Table. 2 shows the summarized conclusions of the analysis of the emission factor calculation and Graph 5, Graph 6 and Picture 7 present the load duration curves for the National Interconnected System.

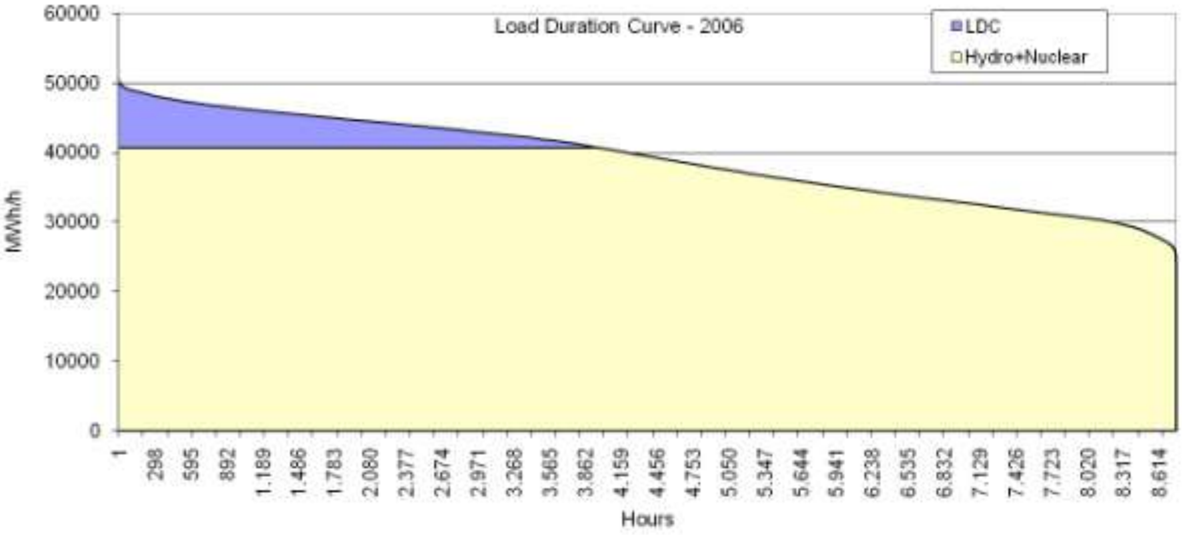
Emission factors for the Costa Rican National Interconnected System

Baseline	EF_{OM}[tCO_2/MWh]	λ_y	Generation [MWh]
2005	0.9416	0.5674	8,215,094
2006	0.9065	0.4784	8,612,894
2007	0.9368	0.3933	8,918,753
	$EF_{OM, simple-adjusted}$ 0.4850	$EF_{BM,2007}$ 0.0976	
	Weights_wind and solar projects w_{OM} = 0.75 w_{BM} = 0.25		**EF_y [tCO_2/MWh]** **wind and solar projects** **0.3882**

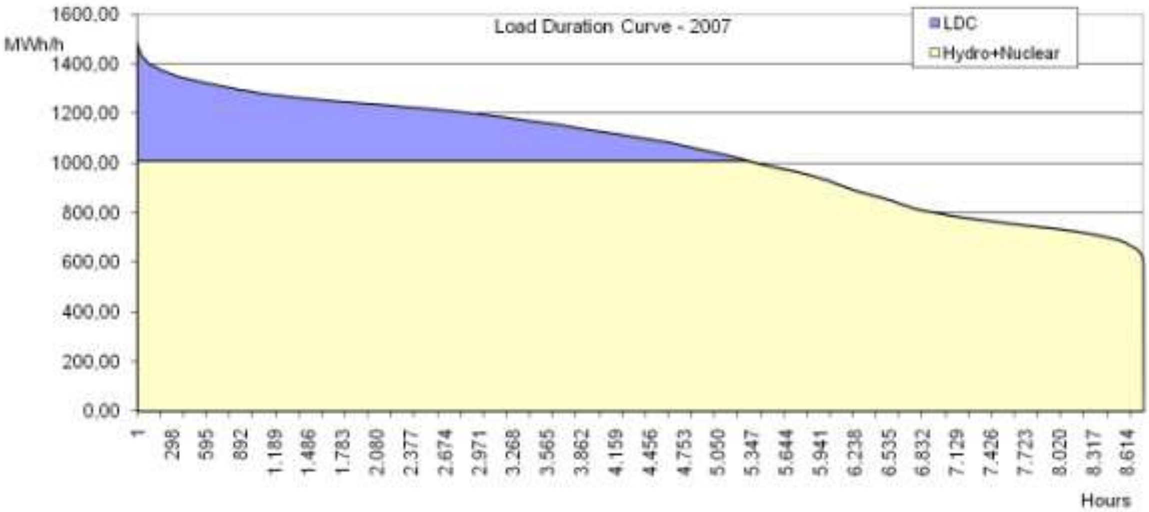
Table. 2 – Emision factor for the NIS system



Graph 5 – Load duration curve for the NIS system, 2005



Graph 6 – Load Duration curve for the NIS system, 2006



Picture 7 – Load Duration curve for the NIS system, 2007.

The build margin sample of units is presented below:

Company	Year of starting operation	Source	Generation 2007 [MWh]
Cariblanco	2007	Hydro	140,076
Pujol Marti	2006	Fossil fuel	136,765
Ingenios (Taboga)	2003/2004	Bagasse	12,911
Miravalles V	2003	Geothermal	93,388
Peñas Blancas	2002	Hydro	170,908
Moín CNFL	2002	Fossil fuel	119,653
Angostura	2000	Hydro	874,524
Miravalles III (BOT)	2000	Geothermal	415,172
Total			**1,963,396.47**

Table. 3 – Group m, set of power capacities used in Build Margin calculus[40]

[40] All links and references presented in the EF calculation sheet

Annex 4

MONITORING INFORMATION

The Monitoring Plan is described in B.7.2.