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

CONTENTS

SECTION A. General description of project activity

A.1. Title of the project activity:

Poechos I Project ("The Project")
Version 02
Date of the document: 24/10/2011

A.2. Description of the project activity:

The Project is a hydroelectric power plant located in Peru, in the North-western Department of Piura. The Project's installed capacity and projected yearly average generation is 15.2 MW and 57,740 MWh per year, respectively. The expected load factor is 43.36%. The Project has displaced in average 36,497 tCO_2e per year in its first 6 years of operation, which accounts an estimation of 255,479 tCO_2e for the first crediting period (7 years), generating the equivalent amount of Certified Emission Reductions (CERs). Methane and Carbon Dioxide emissions from the project are negligible and there is no need to monitor leakage, which will not be taken into account when calculating ERs.

The Project takes advantage of the existing Poechos reservoir of 48 m height and approximately 1,000 m length (with a water discharge of 45 m^3/s), constructed between 1971 and 1974, exclusively for the irrigation system named Chira-Piura1. The machine house was built downstream at the bottom gate of the dam. The Project uses a portion of the discharged water from the Poechos Dam, affecting the flow of the Chira River and the Miguel Checa Canal. The water concession granted to the sponsors by the Peruvian Department of Agriculture was based upon the use of the flow required for agriculture – so that generation received lower priority than agricultural needs. Although the reservoir allows for a multi-year regulation of the water, The Project will not have facilities to regulate its energy production because the control of the discharges is managed by the Agricultural Authority of the region.

The spatial extent of The Project boundary is the National Electric Grid (SEIN). The Project is connected to the SEIN through the Sullana Substation - which belongs to Electronoroeste S.A. (ENOSA). The expected 57,740 MWh of electricity generated per year is sold to ENOSA (stated-owned enterprise) – a PPA is currently signed between SINERSA (The Project Operator and Sponsor) and ENOSA. The Project will have an expected minimum plant operating life of 40 years.

The Project contributes to sustainable development by:

a) Helping SEIN keep thermal power plants shut down and use them only for stand-by power generation, thus displacing expensive generation fired by heavy fuel, diesel, coal and natural gas, while reducing GHG emissions;

b) Employing local labor in construction and plant management;

c) Facilitating electricity access by serving local demand;

d) Contributing to Peru's fiscal accounts through the payment of taxes;

e) Helping Peru improve its hydrocarbon trade balance through reduction of oil imports to be used for electricity generation; and,

f) Improving local education and technical training opportunities, which have been committed to by SINERSA.

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)
Peru (host)	Sindicato Energético S.A. (SINERSA)	No
Netherlands	IBRD as a Trustee of the Netherlands Clean Development Mechanism Facility ("the NCDMF").	Yes
(*) 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.		
Note: *When the PDD is filled in support of a proposed new methodology (forms CDM-NBM and CDM-NMM),* at least the host Party (ies) and any known project participants (e.g. those proposing a new methodology) shall be identified.		

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

Republic of Peru

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

Department of Piura (Piura Region) / Sullana Province / Lancones District.

A.4.1.3. City/Town/Community etc.:

Lancones Town (capital of the Lancones District)

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

The Project is located in the North-western Peruvian Department of Piura, in the Sullana Province, in the Lancones District, in the Lancones Town. The Project site is 40 Km from the Sullana district (capital of the Sullana Province), and 30 km from the Peruvian-Ecuadorian border. The power house is located 81 meters above sea level. The plant is located within the property of the Poechos dam, built over the Chira River[1].

The coordinates of the project are: Latitude:4^{o}41´03.74´´ South , Longitude 80^{o}31´30.68´´ West.

Satellite picture of the project site

[1] In 1974, with the solely purpose to provide irrigation for 110,000 has. in the Chira and Piura valleys.

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

The Project falls into:
Sectoral Scope Number: 1
Sectoral Scope: Renewable Energy
Project Activity: Grid-connected renewable power generation; electricity capacity addition from a hydro power project with existing reservoir where the volume of the reservoir is not increased.

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

The technology employed is based on conventional Kaplan turbines (2) and generators (2) that are widely used all over the world.

The penstock of the powerhouse is connected to the existing steel pipe of the bottom outlet. The penstock is bifurcated in two penstock pipes leading to a powerhouse with two generating units each of 7.6 MW capacity. The generating units consist of two Kaplan turbines coupled to synchronous generators (3-phase) each of 9.5 MVA nominal capacity. That part of the powerhouse in which the main equipment is installed is an underground reinforced concrete structure, whereas the other part is an above ground steel structure. The water is discharged into a tailrace channel (capacity 45 m^3/s) connected to the existing energy dissipater (stilling basin) of the bottom outlet and, hence, is fed back into the irrigation system.
The control building is installed adjacent to the powerhouse. This building contains the control room, offices and auxiliary installations. The control room is equipped with a modern system for automatic and remote control (SCADA).

The project does also contain a 60 kV open-air switchyard with one main transformer of 29 MVA capacity. The power plant is connected to the national grid through a new 60 kV overhead transmission line. The transmission line has a length of 38-km and is connected to the existing Sullana substation.

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

According to the "Guidelines for completing CDM-SSC-PDD" the estimated amount emission reduction over the second crediting period are as follows:

Year	Annual estimation of emissions reductions in tons of CO_2e
2011	24,637
2012	32,850
2013	32,850
2014	32,850
2015	32,850
2016	32,850
2017	32,850
2018	8,213
Total estimated reductions (tons of CO_2e)	229,950
Total number of crediting years	7
Annual average over the crediting period of estimated reductions (tones of CO_2e)	32,850

For the Project "the year" would run from April 1 to March 31, ,the first year of the second crediting period being April 1,2011-March 31, 2012, and the last year of the second crediting period being April 1,2017-March 31, 2018.

A.4.5. Public funding of the project activity:

The Project has not received any type of public funding or public financial help.

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:

According to the "Procedures for renewal of the crediting period of a registered CDM project activity", (version 05, EB 46), paragraph 2(a), the latest approved version of a baseline and monitoring methodology, applied in the original CDM-PDD of the registered CDM project activity, shall be used whenever applicable.

In this case, Approved consolidated baseline and monitoring methodology ACM0002 "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" Version 12.1.0 is applied for this project.

This methodology also refers to the latest approved version of the following tool:

• Tool to calculate the emission factor for an electricity system (ver 02.2.1.);

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

The Project is a grid-connected zero-emission renewable power generation activity and meets all the conditions stated in The Methodology (ACM0002 ver. 12.1.0). These conditions are:

• The Project supplies electricity capacity addition (15.2 MW) from a hydropower source; it is a hydropower plant with existing reservoir where the volume of the reservoir is not increased.

• The Project is not an activity that involves switching from fossil fuels to renewable energy at The Project site

• The electricity grid (the SEIN) is clearly identified and information on the characteristics of this grid is available.

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

Source		Gas	Included	Justification/Explanation
Baseline	CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity	CO_2	Yes	Main emission source.
		CH_4	No	Minor emission source.
		N_2O	No	Minor emission source.
Project Activity	For hydro power plants, emissions of CH_4 from the reservoir	CO_2	No	Minor emission source.
		CH_4	No	In the case of this project, the reservoir has not increased therefore no CH_4 emissions would occur.
		N_2O	No	Minor emission source.

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

According to the "**Procedures for renewal of the crediting period of a registered CDM project activity**, (version 05, EB 46), paragraph 2(a), it has been used the "Tool to assess the validity of the original/current baseline and to update the baseline at the renewal of a crediting period", to assess validity of the original baseline and its update.

The tool consists of two steps. The first step provides an approach to evaluate whether the current baseline is still valid for the next crediting period without need to evaluate the baseline scenario. The second step provides an approach to update the baseline in case that the current baseline is not valid anymore for the next crediting period.

Given that the project activity is the installation of a new grid-connected renewable power plant/unit, the *baseline scenario* is the following:

Electricity delivered to the grid 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) calculations described in the "Tool to calculate the emission factor for an electricity system" (version 02.2.1). (a) A combined margin (CM), consisting of the combination of operating margin (OM) and build margin (BM). As per paragraph 3 of the procedures for renewal of the crediting period of a registered CDM project activity, it does not require a reassessment of the baseline scenario and hence the above mentioned baseline scenario is still applicable for the project activity for the second crediting period.

Application of the Tool to assess the validity of the original/current baseline and to update the baseline at the renewal of a crediting period

Step 1: Assess the validity of the current baseline for the next crediting period

The "Procedures for the renewal of the crediting period of a registered CDM project activity" approved by the CDM Executive Board require assessing the impact of new relevant national and/or sectoral policies and circumstances on the baseline. The validity of the current baseline is assessed using the following Sub-steps:

Step 1.1: Assess compliance of the current baseline with relevant mandatory national and/or sectoral policies

As explained in the original PDD, the baseline, and the alternatives to the project, continue to be ruled by the Electric Concession law – ECL (law 25844) released in 1992. This law regulates all activities related to the generation, transmission and distribution of electric energy.

Following the issuance of this law, state-owned enterprises were privatized and investments in new power generation plants and transmission systems became the domain of private companies. The Law sets forth the norms of operation of the interconnected electric systems, for which an autonomous entity named Committee of Economic Operation of the Electric System (COES) was created. COES is made up of the shareholders of generation companies and of the main transmission system, and the state, the distribution companies or consumers do have any participation. COES is responsible for the coordination of the National Grid (It is called SEIN that is the abbreviation of Sistema Electrico Interconectado Nacional) system operation at minimum cost, guaranteeing the security of the electric power supply and the best use of energy resources. The new regulatory model proposes private initiatives of new investment in power generation.

Electric Concession Law (ECL) is still in force and its relevant articles cited in the original PDD remain the same with a few minor changes, e.g., related to EIA requirements, that do not affect the baseline.

The chart below provides an analysis of the articles under the ECL:

Electric Concession Law – ECL Selected articles and analysis

	Description in the first crediting period PDD	Changes after the submission of the first crediting period PDD	Comments
Article 1	Electricity generating activities can be developed by natural or juridical persons, whether they are national or foreigners. The juridical persons (private companies) should be incorporated under Peruvian laws;	None	
Article 3	A Concession is required for the development of hydro power plants (or geothermic plants13) if their installed capacity is greater than 10 MW	Now all renewable projects with installed capacity greater than 500 KW required a concession	Concession is required for projects that take advantage of public goods as renewable resources. The impact over the baseline is neutral since the changes have relaxed the same requisites for thermal and hydro projects. Before these changes, both thermal and hydro projects, need and environmental Impact Assessment if the power capacity was greater than 10 MW, now it has to be greater than 20 MW (See article 25). In addition, the change does not affect the baseline since the changes were issued in year 2008 and are not retroactive. Besides these changes would not prevent the alternatives presented in the original PDD.
Article 4	An Authorization is required to develop fossil-fuel thermal plants if their installed capacity is greater than 500 KW, and hydropower plants and geothermic plants if their installed capacity is less than or equal to 10 MW	Fossil-fuel thermal plants with installed capacity greater than 500 KW still required authorization. Hydropower plants and geothermic plants have been erased from this article due to the change in article 3.	
Article 6	The Concessions and Authorizations can be granted by the MINEM, who would establish for that a Registration of the Electric Concessions.	None	
Article 7	Electricity generating activities that do not required Concession or Authorization could be developed freely upon compliance with technical norms and dispositions of environmental conservation and Cultural Patrimony conservation - the owner of the title of these activities should inform the MINEM the initiation of activities and the technical characteristics of the project and installations.	None	
Article 9	The Peruvian Government preserve the environmental conservation and the Cultural Patrimony of the Nation, as well as the rational use of the natural resources in the development of activities related to generation, transmission and distribution of electricity	None	

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Regarding the policies and circumstances that promote the support of the realistic and credible alternative of natural gas power plants have been effective and confirmed. The natural gas of Camisea has been operational since August 2004 and most of the new additions have been natural gas thermal plants.

The table below shows the new additions to the SEIN since 2004, the year in which the Camisea natural gas project was commissioned:

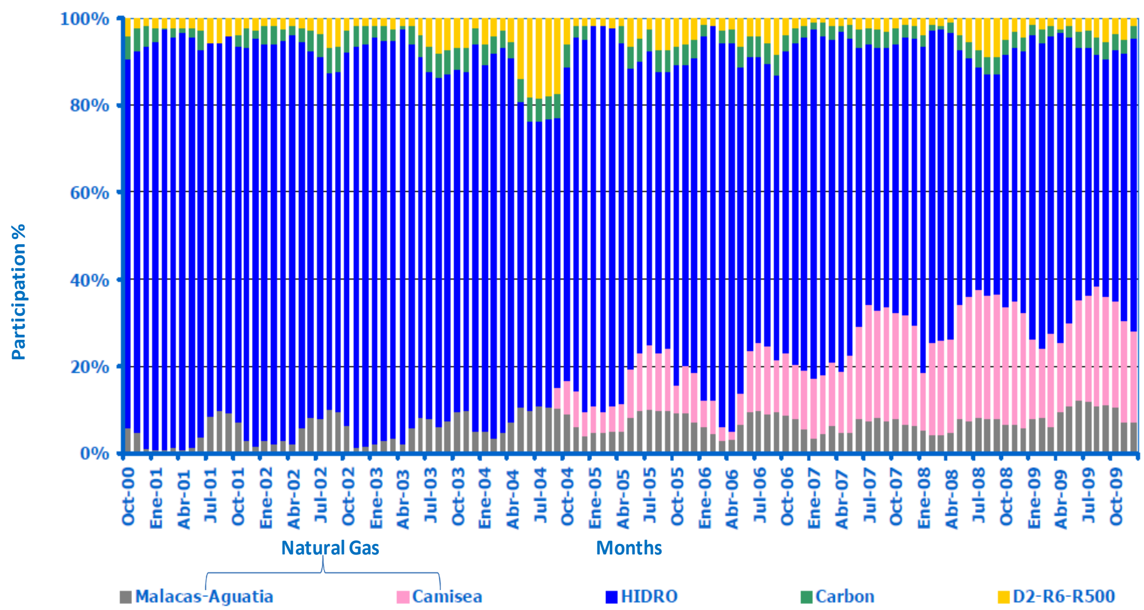
Additions to the SEIN from 2004 to 2009[2]

Enterprise	Power plant	Unit	Type	Effective installed Capacity (MW)	Date of Commissioning	Comments
EDEGEL	Ventanilla	TG3	Turbo Gas	164.1	08/09/2004	Natural Gas from Camisea
		TG4	Turbo Gas	160.5	29/09/2004	Natural Gas from Camisea
EDEGEL	Santa Rosa Westinghouse	TG7	Turbo Gas	121.3	01/06/2005	Natural Gas from Camisea
EDEGEL	Santa Rosa UTI 5 & 6	UTI 5, UTI 6	Turbo Gas	109	01/06/2006 - 01/08/2006	Natural Gas from Camisea
EDEGEL	Ventanilla	TG3 , TG4	Combined Cycle	450	01/10/2006	Natural Gas from Camisea
ENERSUR	Chilca TG1	TG1	Turbo Gas	175.96	01/12/2006	Natural Gas from Camisea
Kallpa Generacion	Kallpa	TG1	Turbo Gas	184	24/07/2007	Natural Gas from Camisea
ENERSUR	Chilca TG2	TG2	Turbo Gas	175.96	07/08/2007	Natural Gas from Camisea
SDF ENERGIA	Oquendo		Turbo Gas	29.38	19/01/2009	Natural Gas from Camisea
Kallpa Generacion	TG2 Kallpa	TG2	Turbo Gas	193.52	19/06/2009	Natural Gas from Camisea
ELECTROPERU	Trujillo Norte		Diesel 2	62.13	28/06/2009	Diesel
ENERSUR	TG31 Chilca	TG31	Turbo Gas	194.19	22/07/2009	Natural Gas from Camisea
EDEGEL	Santa Rosa TG8	TG8	Turbo Gas	199.83	01/08/2009	Natural Gas from Camisea

Source: COES

In the figure below it is showed the Evolution of Energy Generation in the SEIN per Source. The blue section is hydro; the other colors are thermal plants. Color pink is energy participation using natural gas of Camisea

[2] According to the CDM rules and the recent clarification of the 38 meeting of The Executive Board paragraph 60, in the context of conducting common practice analysis, project participants may exclude registered CDM project activities and project activities which have been published on the UNFCCC CDM website for global stakeholder consultation as part of the validation process. Therefore, the hydropower plant projects of Callahuanca and Yuncan have been excluded from the table because of their CDM status. The first is a registered CDM project and the second has been published in the UNFCCC CDM website during the validation process.



Source: Estadística de Operaciones 2009. COES. Figure Number 2.6.B.

Therefore, the project baseline on the second crediting period remains the same. This baseline is the most plausible and it doesn't need to be actualized

Since the current baseline complies with all relevant mandatory national and/or sectoral policies which have come into effect after the submission of the project activity for validation and are applicable at the time of requesting the renewal of the crediting period, go to Step 1.2.

Step 1.2: Assess the impact of circumstances

As seen previously, the baseline is in compliance with the law and actual circumstances ensure the continuity of the baseline i.e. generation of power from grid mix.

It is important to mention that after the submission of the PDD of the first crediting period, a law for the promotion of renewable energy was issued in May 2008. This law allows renewable projects under 20 MW of power capacity built after the issuance of this law, to apply to a special tariff through bidding. The first bidding was made in February 2010 and 161.71 MW of power capacity were awarded to 17 hydro power plants. Some of these power plants have entered in operation after May 2008 and other have to be built before year 2012. The impact in the baseline is small relatively to the size of the national grid[3] even considering the objective of the government to reach 500 MW of power capacity through this law until year 2012. Moreover, 5of these 17 projects are already registered CDM projects and the other are applying to it.

Since this law was issued 5 years after the commission of Poechos I, the project is not qualified and therefore did not benefit of any of its incentives during its construction stage and commercial operation.

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[3] According to COES annual statistics 2009, in year 2009 the power effective capacity of the national grid was 5,848 MW which 48.88% is hydro and the remaining 51.12% is thermal.

There is sufficient market information to calculate the parameters needed to update the baseline.

Any changes to circumstances that affect the grid mix are reflected in the grid emission factor and hence the baseline emission.

The plant still has the same technical characteristics and energy sources and its energy production has been sold to ENOSA (stated-owned enterprise). These circumstances continue during the second crediting period.

Financing from the Clean Development Mechanism, sale of CERs, as was mentioned in the original PDD has been alleviating financial constraints faced by the project and the continued availability of CER revenue the impact of the CDM over the project performance and social investments is expected to be strengthened in the second crediting period.

Therefore, based on the "Tool to assess the validity of the original/current baseline and to update the baseline at the renewal of a crediting period", continued validity of the original baseline is established for the second crediting period.

Step 1.3: Assess whether the continuation of the use of current baseline equipment(s) is technically possible

The project activity involves a hydro power plant where in the absence of the project activity, the project participants would not have constructed the plant but where the electricity would have been generated in other existing plants and/or in new plants constructed by third parties elsewhere. At the beginning of the first crediting period, it was stated in the PDD that the expected minimum plant operating life is 40 years. After 7 years, it can be established that the remaining technical lifetime of the equipment is still beyond the end of the second crediting period (7 years) for which renewal is requested. Therefore, it is established that the continuation of the current baseline equipment is technically possible.

Step 1.4: Assessment of the validity of the data and parameters

The IPCC 1996 defaults value used for emission factor calculations were determined at the start of the crediting period and not monitored during the first crediting period. IPCC released new Guidelines for National Greenhouse Gas Inventories in 2006. Default values are still the same however the Tool to calculate the emission factor for an electricity system asks to use IPCC default values at the lower limit of the uncertainty at a 95% confidence interval. The IPCC default values have been updated accordingly for the second crediting period.

Step 2 "Update the current baseline and the data and parameters" .
Step 2.1: Update the current baseline
By applying steps 1.1, 1.2 and 1.3 of the Tool, it has been confirmed that the current baseline continues to be valid for the second crediting period.

Step 2.2: Update the data and parameters
Step 1.4 showed that IPCC default values have to be updated in the current baseline. In the current PDD the IPCC default values have been updated accordingly following the guidance in Step 1.4.

According to the “Procedures for renewal of the crediting period of a registered CDM project activity”, it is necessary to update the original CDM-PDD with the latest approved version of a baseline and monitoring methodology applied.

In this case, the approved consolidated baseline and monitoring methodology ACM0002 “Consolidated baseline methodology for grid-connected electricity generation from renewable sources” Version 12.1.0 is applied. This methodology also refers to the latest approved version of the following tool: “Tool to calculate the emission factor for an electricity system (ver 02.2.1.)” which defines the baseline emission factor for the project activity and has been applied accordingly.

Application of the Tool to calculate the emission factor for an electricity system”

Following “Tool to calculate the emission factor for an electricity system (version 02.2.1)”, the baseline emission factor is calculated as a combined margin (CM), consisting of the simple average of the operating margin emission factor (OM) and the build margin emission factor (BM). All margins are expressed in tCO_2e/MWh.

CM= 0.25*OM + 0.75*BM

According to the Tool, the combined margin is deemed to represent the tCO_2e/MWh that would have been emitted in the absence of The Project. Emissions reductions will be claimed based on the total CO_2e emissions mitigated by The Project. The Project Boundary considered is The SEIN. No leakages or indirect emissions were identified for The Project.

The following six steps have to be followed in order to calculate the baseline emission factor:

STEP 1. Identify the relevant electricity systems.

The power plant is connected to the national grid through a new 60 kV overhead transmission line. The transmission line has a length of 38-km and is connected to the existing Sullana substation - which belongs to Electronoroeste S.A. (ENOSA).

Electricity imports or exports from other grid have been neither reported by the SEIN dispatch center of nor the Ministry of Energy and Mines.

If it would be the case, for the purpose of determining the operating margin emission factor, it will be assumed a CO_2 emission factor(s) for net electricity imports 0 tCO_2/MWh;

Electricity exports should not be subtracted from electricity generation data used for calculating and monitoring the electricity emission factors.

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

Project participants may choose between the following two options to calculate the operating margin and build margin emission factor:
Option I: Only grid power plants are included in the calculation.
Option II: Both grid power plants and off-grid power plants are included in the calculation.
Since project participants considered only grid power plants for the calculation of the operating margin and build margin emission factor, Option one is selected.

STEP 3. Select a method to determine the operating margin (OM).

Out of four options for the OM, the Dispatch Data Analysis OM (OM-DD) was selected. The Simple OM method cannot be used since low cost, must-run resources constitute more than 50% of total grid generation in Peru. Also, it was not necessary to use either the Simple Adjusted OM approach or the Average OM approach because detailed dispatch data is available.

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

The dispatch data analysis OM emission factor (EFgrid, OM-DD,y) is determined based on the grid power units that are actually dispatched at the margin during each hour h where the project is displacing grid electricity. This approach is not applicable to historical data and, thus, requires annual monitoring of EFgrid, OM-DD,y. The formulas are described in section: B.6.1.

For The Project "the year" would run from April 1st to March 31st, being the first year of the second crediting period April 1,2011- March 31, 2012 and the last year of the second crediting period April 1, 2017-March 31, 2018.

Following this approach, the BLS's resulting Dispatch Data Analysis Operating Margin Emission Factor (EFgrid,OM-DD,y) calculated prior to validation for year April 1st ,2009 – March 31st ,2010[4] was **0.75579 tCO_2e/MWh** .

Step 5: Calculate the build margin (BM) emission factor

The BM emission factor is defined in The tool as the generation-weighted average emission factor (tCO_2e/MWh) of a sample of power plants. Such sample should be composed by either the 5 most recently built plants or the plants whose aggregated generation comprises the most recent 20% of SEIN generation in the year of project generation occurrence, whichever group's generation is greater – both list should exclude CDM-Status Plants. The Methodology, gives 2 options for the calculation of the BM.

The second option was selected (BM2) in the BLS for the sake of conservativeness – this option does not include in-construction plants in the sample and must be updated annually ex-post for the first crediting period. For the second crediting period, the build margin emissions factor shall be calculated ex ante, based on the most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation of the renewal crediting period. Since this is the second crediting period for this project the BM would be calculated ex ante.

In the monitoring of The Project's CERs, the plants capacity additions to consider in the BM is obtained by reviewing annual statistics of new additions in the *SEIN* across latest years, and by selecting from these additions identified, only the ones that represent new units added.

The formulas are described in section: B.6.1.

Following this approach, the BLS's resulting Build Margin Emission
Factor (EFgrid,BM,y) was **0.50665 tCO_2e/MWh** .

[4] This the last year of data of Poechos I available at the time of the renovation of the the PDD.

Step 6. Calculate the combined margin (CM) emissions factor.

The combined margin emissions factor is calculated as follows:

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

Where:
$EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year y (tCO_2/MWh)
$EF_{grid,OM,y}$ = Operating margin CO_2 emission factor in year y (tCO_2/MWh)
W_{OM} = Weighting of operating margin emissions factor (%)
W_{BM} = Weighting of build margin emissions factor (%)

The following default values should be used for wOM and wBM:
$W_{OM} = 0.5$ and $W_{BM} = 0.5$ for the first crediting period, and $W_{OM} = 0.25$ and $W_{BM} = 0.75$ for the second and third crediting period.

Since this PDD refers to second crediting period the weights of $W_{OM} = 0.25$ and $W_{BM} = 0.75$ are applied

$EF_{grid,CM,y} = EF_{grid,OM,y} \times 25\% + EF_{grid,BM,y} \times 75\%$

The ex-ante value for EFgrid,CM,y is: **0.56893 tCO_2e/MWh** .

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):

As per paragraph 2 of the procedures for renewal of the crediting period of a registered CDM project activity, for the preparation of a revised PDD "Project participants shall update those sections of the project design document (CDM PDD) relating to the baseline, estimated emission reductions and the monitoring plan using an approved baseline and monitoring methodology"; therefore section B.5 on assessment and demonstration of additionality remains to be the same as that for the registered PDD.

The following steps from the "Tools for the demonstration and assessment of additionality" (EB16 Report) will be completed in this section:

Step 0: Preliminary screening based on the starting date of the project activity
Step 1: Identification of alternatives to the project activity consistent with current laws and regulations
Step 2: Investment analysis to determine that the proposed activity is not the most economically or financially attractive;
Step 3: Barriers analysis
Step 4: Common practice analysis
Step 5: Impact of registration of the proposed activity as a CDM project activity

Based on information about activities similar to the proposed activity, the common practice analysis is to complement and reinforce the investment and barrier analysis.

Step 0 - Preliminary screening based on the starting date of the project activity:
During 2001, the World Bank and the Government of Peru undertook a National Strategy Study (NSS) with the purpose of positioning the country towards the new CDM market. Part of the study aimed at identifying possible CDM projects in Peru. Finanzas Ambientales, a local CDM consultancy on its capacity of NSS consultants identified Poechos I (The Project) as a possible CDM candidate. The Project sponsors retained Finanzas Ambientales as their own advisor for the CDM component of The Project, and a preliminary PDD was elaborated in February 2002 showing the sponsors' early determination in including Carbon Finance as an integral part of their project's design. Documented proof of these facts is made available to the DOE. The loan agreement to fund The Project was signed in October 2002 fully integrating Carbon Finance cash flows in the financial models. **Construction started in November 2002.**
Project participants do wish to have the crediting period starting prior to the registration of The Project activity.

The plant was commissioned in April 2004. The Project has been ready for CDM Registration since May 2003, but project sponsors chose to wait until a grid-connected electricity methodology was formally approved.
For all of above, The Project is eligible for attaining a crediting period starting in April 1st, 2004 before its date of registration.

Step 1 - Identification of alternatives to the project activity consistent with current laws and regulations
Sub-step 1a. Define alternatives to the project activity:

The identified realistic and credible alternatives available to The Project participants that provide outputs or services comparable with the proposed CDM project activity are three:

1) Implement The Project as a hydropower plant development without CDM assistance
2) Implement The Project as a natural gas power plant
3) Do not implement any power generation project

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

The identified alternatives are in compliance with all applicable legal and regulatory requirements. The 3 identified alternatives comply with Peru's ECL (Law 25844) released in 1993. Some relevant Articles of Peru's ECL that indicate that the alternatives are a plausible possibility for the project participants are: a) From Article 1- electricity generating activities can be developed by natural or juridical persons, whether they are national or foreigners. The juridical persons (private companies) should be incorporated under Peruvian laws; b) From Article 3 - A Concession is required for the development of hydro power plants (or geothermic plants13) if their installed capacity is greater than 10 MW, c) From Article 4 – An Authorization is required to develop fossil-fuel thermal plants if their installed capacity is greater than 500 KW, and hydropower plants and geothermic plants if their installed capacity is less than or equal to 10 MW, d) From Article 6 – The Concessions and Authorizations can be granted by the *MINEM*, who would establish for that a Registration of the Electric Concessions. e) From Article 7 – electricity generating activities that do not required Concession or Authorization could be developed freely upon compliance with technical norms and dispositions of environmental conservation and Cultural Patrimony conservation - the owner of the title of these activities should inform the *MINEM* the initiation of activities and the technical characteristics of the project and installations. F) From Article 9 – The Peruvian Government preserve the environmental conservation and the Cultural Patrimony of the Nation,

as well as the rational use of the natural resources in the development of activities related to generation, transmission and distribution of electricity.

Because none of the identified alternatives breaks any legal or regulatory requirement, including the fact that none of the three are posed to go against technical norms and dispositions of environmental conservation and Cultural Patrimony conservation, all 3 scenarios are in compliance with all applicable laws and regulations and are also realistic and credible alternatives available to the project participants **-** *Meaning The Project is additional under Step 1.*

Step 2 – Investment Analysis to determine that the proposed activity is not the most economically or financially attractive:
To conduct the investment analysis the following four sub-steps were taken:

Sub-step 2a. Determine an appropriate analysis method
The CDM project activity generates financial and economic benefits other than CDM related income, therefore the Cost Analysis (Option I) cannot be taken. Out of the comparison analysis (Option II) and the benchmark analysis (Option III), the benchmark analysis (Option III) was chosen.

Sub-step 2b - Option III. Apply the benchmark analysis
The identified financial indicator is: **Unit cost of service ($/MWh)**
The indicator for The Project is: **Levelized cost of electricity production ($/MWh**)
The relevant **benchmark** value is the *SEIN* **Long Run Marginal Cost ($/MW)**.

Both unit cost of service ($/MWh) include cost of investment, operation and maintenance and reflect a Present Value $/MWh.

The benchmark represents **standard costs** in the market, considering the specific risk of the project type (power generation), and it is not linked to the subjective profitability expectation or risk profile of a particular project developer.

That The Project is not the most inexpensive alternative in the market will be demonstrated in Sub-step 2c.
Sub-step 2c – Calculation and comparison of financial indicators

Calculation of the levelized cost of The Project, which includes Investment (I) and Operation and Maintenance (O&M) Costs

Levelized Cost of The Project:
The formula to calculate the levelized cost is the following[5]:

Cost per MWh = [Investment x CRF + O&M Annual] /Annual Generation (MWh)
Where,

Investment: Total investment in The Project ($) **-** not including VAT =$16.9 million.
In the present calculation the VAT is added but discounted by the fiscal credit, the final financial cost of this was calculated to be 4% over $16.250 Million, which gives $16.9 Million.

CRF: Capital Recovery Factor =0.14077

[5] Detailed data for calculation and modeling of Minimum Cost Expansion Plan is in Annex 3 under “Details of LRMC variables”.

CRF =Equivalent Annual Cost of the Capital Investment/ Initial Capital Cost

CRF = (Annuity of $16.9 million[6] at 14% discount rate and 40 years of annual payments[7]) / $16.9 million

CRF= 2.379/ 16.9 = 0.14077

O&M: Annualized Operation and Maintenance costs. It does neither include financial costs nor income tax[8]. = 0.225 million
Includes variable costs (additives, lubricants, spares, materials and other maintenance expenses); and fixed costs (payroll expenses for employees in charge of the plant operation, plant supervision, plant maintenance, plant security and other general expenses)

Generation: Annual Average Generation in MWh = 57,740 MWh[9]

The calculation for The Project levelized cost is the following:

Levelized Cost for Poechos I

	Unit	The Project (Poechos)
Capacity	MW	15.2
Total Investment	$Million	16.9
Annual Cost:		
Capital	$Million	2.379
O&M	$Million	0.225
Total Annual Cost	$Million	2.604
Plant Factor	%	43.36%
Generation	MWh	57,740
Levelized Cost	**$/MWh**	**45.09**

Source: Single parameters where provided by The Sponsor. The calculation of the levelized cost is own production.

$2.379 million = Annual Equivalent Cost of the Capital Investment[10]

+$0.225 million = Annualized O&M
2.604 million
2.604 million / 57,740 MWh= **$45.09 / MWh**

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[6] Being 16.9 the Present Value of the Annuity.

[7] And Zero ending Cash Balance.

[8] For the latter will depend on an unknown variable which is The Project net income.

[9] The Project's estimated annual generation of 57,740 MWh. (calculated with a installed capacity of 15.2 MW) includes losses in transmission but does not included losses in distribution, according to The Sponsor. Moreover, Poechos I electricity meter is located in the Sullana Substation which means that all electricity registered by The Project includes already the losses that occur in the 38-Km transmission line (losses in transmission). The only reason why The Project's losses in distribution were considered to be zero for the calculation of The Project's levelized cost was: Conservatism. If losses in distribution had been considered in The Project's levelized cost calculation, the levelized cost of The Project would have gone up. This is because the levelized cost of The Project is calculated as the Equivalent Annual Cost of The Project divided by The Project's annual electricity dispatched to the *SEIN*. If the denominator had been decreased ("generation minus losses in transmission **minus losses in distribution**") the ratio would have gone up and The Project would have shown to be even less financially attractive than it was demonstrated to be in the Investment Analysis. Losses in distribution depend on the MW distributed. For The Project, losses in distribution are estimated to be within 1%-2%, according to the Sponsor. Considering this range the project levelized cost would be within 1% and 2% higher than $45.09/MWh, which gives a levelized cost within $45.55/MWh and $46.01/MWh

[10] In Excel [PMT (14%, 40, 16.9, 0)] = Annuity of $16.9 million at 14% discount rate and 40 years of annual payments, being $16.9 million the Present Value of the Annuity.

Calculation of the LRMC of the SEIN, which includes Investment (I) and Operation and Maintenance (O&M) Costs

The Long Run Marginal Cost of the SEIN (LRMC):

The LRMC ($/MWh) is the equivalent cost per MWh estimated to supply the additional demand of the SEIN in future years (2007-2017, for this forecast). This cost includes Investment and Operations and Maintenance costs. The LRMC is calculated taken into account the additional future demand and the cost incurred to serve that demand, with Investments in new plants and the Operational and Maintenance cost of both new and existent plants (according to a dispatch simulation). The LRMC calculation considers that the new capacity addition installed will be fulfilled with the most economically efficient alternatives available in the market.

The LRMC was calculated by using the Wien Automatic System Planning Package (WASP). The WASP generated sequences of projects that comply with limit values for maximum and minimum reserves for each alternative technology specified. The WASP targets at minimizing the LRMC of the SEIN.

The LRMC uses the following formula:

$$\text{LRMC} = \frac{\sum_{i=1}^{n} \frac{I_i}{(1+r)^i} + \sum_{i=1}^{n} \frac{O\,\&\,M_i}{(1+r)^i} + \sum_{i=1}^{n} \frac{NSE_i}{(1+r)^i}}{\sum_{i=1}^{n} \frac{D_i}{(1+r)^i}}$$

Source: *MINEM*

Where:

I:	Sum of Equivalent Annual Investment Costs for a year
O&M:	Annual Costs in Operation and Maintenance
NSE:	Annual Losses in Distribution and Transmission
D:	Annual Demand Projected
r:	Discount rate: 14%
n:	2007-2017

Calculation of LRMC of The *SEIN*

Year	Demand GWh	Incremental Demand GWh	I [1] 1000$	O&M [2] 1000$	NSE 1000 US$	Total Cost 1000 US$
2006	23219.4	-	-	-	-	-
2007	24061.9	843	8,853	14,740	0	23,593
2008	24935.4	1,716	36,165	9,770	0	45,935
2009	25789.3	2,570	36,165	34,340	0	70,505
2010	26681.4	3,462	45,018	48,480	0	93,498
2011	27587.9	4,369	72,329	47,190	0	119,519
2012	28548.6	5,329	72,329	67,870	0	140,199
2013	29539.3	6,320	108,494	75,870	0	184,364
2014	30563.2	7,344	108,494	92,510	0	201,004
2015	31618.3	8,399	108,494	113,000	0	221,494
2016	32709.9	9,491	117,347	137,600	0	254,947
2017	33839.2	10,620	144,658	145,150	0	289,808
NPV (14%)		20,435	296,326	260,281	-	556,607
LRMC	**27.24**	**$/MWh**				

1. *Equivalent Annual Cost of Capacity Additions selected by WASP.*
2. *Simulation of future supply to attend the projected demand was forecasted by WASP.*

Source: Peru's Sectoral Baseline Study (2003)[11]

Comparison: Both the LRMC and the Project levelized cost are comparable because they have the same nature of components (both I and O&M) and both reflect a present value of $/MWh. Since The Project has a higher cost indicator than the benchmark, $45.09 per MWh is greater than $27.24 per MWh, The Project cannot be considered financially attractive.

Sub-step 2d. Sensitivity Analysis

The following variables will undergo a sensitivity analysis to prove the robustness of the conclusion given in Sub-step 2c.

For the *SEIN* LRMC ($/MWh)[12]:

a) Annual Investment Costs

b) Discount Rate

For The Project Levelized Cost ($/MWh):

a) Load Factor

b) The Initial Investment Cost

c) Discount Rate

Sensitivity Analysis for the *SEIN* LRMC ($27.24/MWh)

(a) Annual Investment Cost and (b) Discount Rate.

SENSITIVITY ANALYSIS FOR THE *SEIN* LRMC (2007-2017)

	Incremental GWh				EAI=Eq.Annual Invest Cost			Discount Rate Sensitivity								
				Data	r=0%			90%*I			100%*I			120%*I		
Y	12%	14%	16%	r=0%	90%	100%	120%	12%	14%	16%	12%	14%	16%	12%	14%	16%
2007	672	649	626	**843**	21,234	**23,593**	28,312	16,927	16,339	15,780	18,808	18,154	17,533	22,570	21,785	21,040
2008	1221	1158	1099	**1,716**	41,342	**45,935**	55,122	29,426	27,904	26,486	32,696	31,005	29,429	39,235	37,206	35,314
2009	1633	1522	1419	**2,570**	63,455	**70,505**	84,606	40,326	37,570	35,045	44,807	41,745	38,939	53,769	50,094	46,727
2010	1964	1798	1648	**3,462**	84,148	**93,498**	112,198	47,748	43,704	40,064	53,053	48,560	44,516	63,664	58,272	53,419
2011	2213	1990	1793	**4,369**	107,567	**119,519**	143,423	54,497	49,006	44,150	60,552	54,451	49,056	72,662	65,341	58,867
2012	2411	2130	1886	**5,329**	126,179	**140,199**	168,239	57,077	50,426	44,646	63,419	56,029	49,607	76,103	67,235	59,528
2013	2553	2216	1928	**6,320**	165,928	**184,364**	221,237	67,015	58,167	50,612	74,462	64,630	56,236	89,354	77,557	67,483
2014	2648	2258	1931	**7,344**	180,904	**201,004**	241,205	65,236	55,629	47,569	72,484	61,810	52,855	86,981	74,172	63,426
2015	2704	2266	1904	**8,399**	199,345	**221,494**	265,793	64,184	53,772	45,188	71,315	59,747	50,209	85,578	71,696	60,251
2016	2728	2246	1855	**9,491**	229,452	**254,947**	305,936	65,962	54,292	44,839	73,291	60,325	49,821	87,949	72,390	59,785
2017	2726	2204	1789	**10,620**	260,827	**289,808**	347,770	66,948	54,137	43,940	74,386	60,152	48,822	89,264	72,183	58,586
	23,475	20,436	17,879		**NPV of Annual Investments=**			575,346	500,947	438,319	639,274	556,608	487,021	767,128	667,930	584,426

90%*I	12%	24.51		
	14%		24.51	
	16%			24.52
100%*I	12%	27.23		
	14%		27.24	
	16%			27.24
120%*I	12%	32.68		
	14%		32.68	
	16%			32.69

Source: Own production

The SEIN *LRMC* is not sensitive to the discount rate but it is to the Annual Investment Cost.

Sensitivity analysis for The Project ($45.09/MWh)

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[11] Developed by a *MINEM* expert in 2003

[12] Note that a sensitivity analysis can not be performed for the LRMC Load Factor, because in the LRMC calculation, the load factor varied per plant, per month, and per year.

(a) Load Factor

LEVELIZED COST FOR POECHOS

40 years of payment 16.9 Investment Cost 14% Discount Rate		LF 100%	Change in Load Factor (LF*%) all else constant			
			120%	**110%**	**90%**	**80%**
Capacity	MW	15.2	15.2	15.2	15.2	15.2
Total Investment	$Million	16.9	16.9	16.9	16.9	16.9
Annual Cost:						
Capital	$Million	$2.38	2.38	2.38	2.38	2.38
O&M	$Million	0.225	0.225	0.225	0.225	0.225
Total Annual Cost	$Million	$2.60	2.604	2.604	2.604	2.604
Plant Factor	%	43.36%	52.04%	47.70%	39.03%	34.69%
Generation	MWh	57,740	69,287	63,513	51,966	46,192
Levelized Cost	**$/MWh**	**45.09**	**37.58**	**40.99**	**50.10**	**56.37**

Source: Own production – The Sponsor provided single parameters.

(a) Load Factor, (b) Initial Investment Cost and (c) Discount Rate Sensitivity Analysis Matrix:

EAI Capital Cost	15.21	I*90%	12%	($1.85)	($1.85)	($1.85)	($1.85)
Figures are in red only			14%	($2.14)	($2.14)	($2.14)	($2.14)
because they represent			16%	($2.44)	($2.44)	($2.44)	($2.44)
outflows (costs)	16.9	I*100%	12%	($2.05)	($2.05)	($2.05)	($2.05)
			14%	($2.38)	($2.38)	($2.38)	($2.38)
			16%	($2.71)	($2.71)	($2.71)	($2.71)
	20.28	I*120%	12%	($2.46)	($2.46)	($2.46)	($2.46)
			14%	($2.85)	($2.85)	($2.85)	($2.85)
			16%	($3.25)	($3.25)	($3.25)	($3.25)
Total Eq.Annual Cost	15.21	I*90%	12%	2.070	2.070	2.070	2.070
			14%	2.366	2.366	2.366	2.366
			16%	2.665	2.665	2.665	2.665
	16.9	I*100%	12%	2.275	2.275	2.275	2.275
			14%	2.604	2.604	2.604	2.604
			16%	2.936	2.936	2.936	2.936
	20.28	I*120%	12%	2.685	2.685	2.685	2.685
			14%	3.079	3.079	3.079	3.079
			16%	3.478	3.478	3.478	3.478
Levelized Cost	15.21		12%	29.88	32.59	39.83	44.81
			14%	34.14	37.25	45.53	51.22
			16%	38.46	41.96	51.28	57.70
	16.9		12%	32.83	35.82	43.78	49.25
			14%	37.58	40.99	50.10	56.37
			16%	42.38	46.23	56.50	63.56
	20.28		12%	38.75	42.28	51.67	58.13
			14%	44.44	48.48	59.26	66.66
			16%	50.20	54.77	66.94	75.30

Source: Own production

Comparing all Levelized Cost obtained with all benchmarks obtained:

Benchmark- Not efficient Market	Change in Investment for Poechos	Discount Rate for Poechos	Change in Load Factor for Poechos (LF*%)			
			120%	110%	90%	80%
Max EAI for the SEIN	15.21	12%	Not Additional	Not Additional	Additional	Additional
32.69		14%	Additional	Additional	Additional	Additional
16% discount rate		16%	Additional	Additional	Additional	Additional
120% Investment Cost	16.9	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional
	20.28	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional

1) Poechos is more efficient than the market when its LOAD FACTOR increases to 52.04%, faces DISCOUNT RATE of 12% and its I is reduced in 10% to $15.21 million (since the latter is not plausible, this scenario can be discarded)
2) Poechos is more efficient than the market when its LOAD FACTOR increases to 47.7%, faces DISCOUNT RATE of 12% and its I is reduced in 10% to $15.21 million (since the latter is not plausible, this scenario can be discarded)

Benchmark- Base Scenario Market	Change in Investment for Poechos	Discount Rate for Poechos	Change in Load Factor (I*%)			
			120%	110%	90%	80%
Medium EAI for the SEIN	15.21	12%	Additional	Additional	Additional	Additional
27.24		14%	Additional	Additional	Additional	Additional
16% discount rate		16%	Additional	Additional	Additional	Additional
120% Investment Cost	16.9	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional
	20.28	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional

Source: Own production

All combination for both scenarios, indicate that The Project is additional except for only two cases. These are when comparing with a Not Efficient Market Benchmark ($32.69), and **r=12%**, The Project **Initial Investment Cost goes down by 10%** and **Load Factors for The Project go up in 10% and 20%, respectively -** These two scenarios can be discarded because it was not possible to decrease the cost of The Project less than $16.9 million.

Both benchmarks, the Medium Efficiency Scenario for the Market and the Most Efficient Scenario for the Market, show that The Project is additional at all discount rates, at all load factors and at all initial investment costs, considered for it.

Since The Project's financial unattractiveness, concluded in Sub-step 2.c., has proved to be robust to reasonable variations in the critical assumptions, The Project is unlikely to be financially attractive – Meaning the Project is additional under Step 2.

<u>Step 3. Barrier Analysis</u>

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

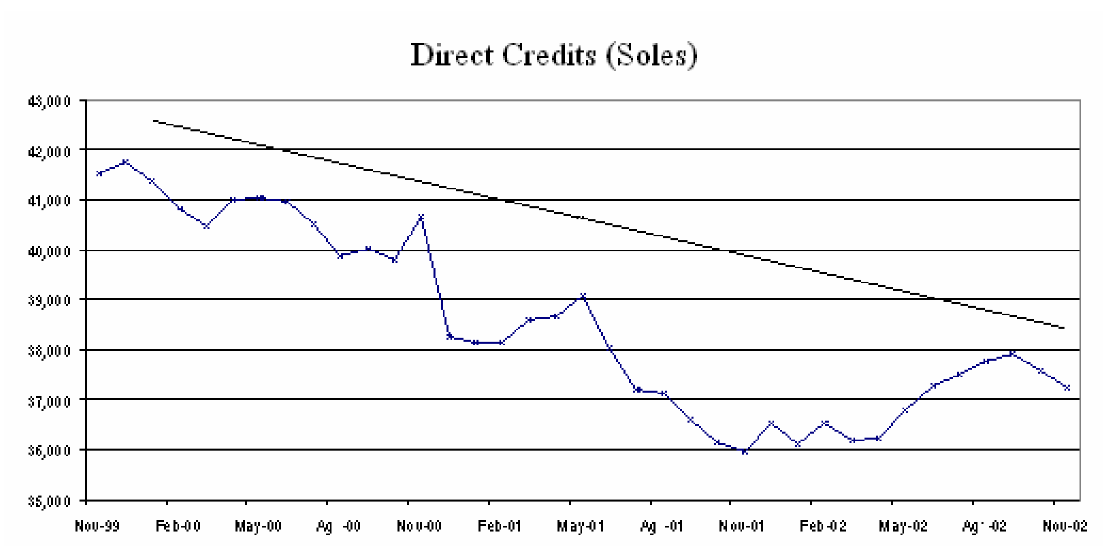
Hydropower plants projects face several types of barriers that prevent them from being carried out if they are not registered as CDM activities. The barriers The Project faced were basically two:

1) A still depressed international investment climate towards emerging markets when The Project started construction in late 2002: A worldwide flight-to-quality phenomenon affected Peru from late 1998 – in 2 ways, preventing international investors to lend to the Peruvian banking system and preventing the Peruvian banking system to lend to highly leveraged projects (commonly highly capital intensive projects) that do not have large companies as project developers (The Project case). The flight to quality worldwide phenomenon was triggered by the successive global emerging markets crisis, which

started in 1997[13], "private capital flows to emerging markets had all dried up by 2001"[14]. Graphs below show the effects of the emerging market crisis. The Project Developer was counting with the CERs before October 2002 -a preliminary PDD was elaborated in February 2002- thus the promise of this future revenue helped to cope with the international climate. The loan agreement to fund The Project was signed in October 2002 fully integrating Carbon Finance cash flows in the financial models.

Net Private Capital Inflows (1985-2003)-(Billions of $)

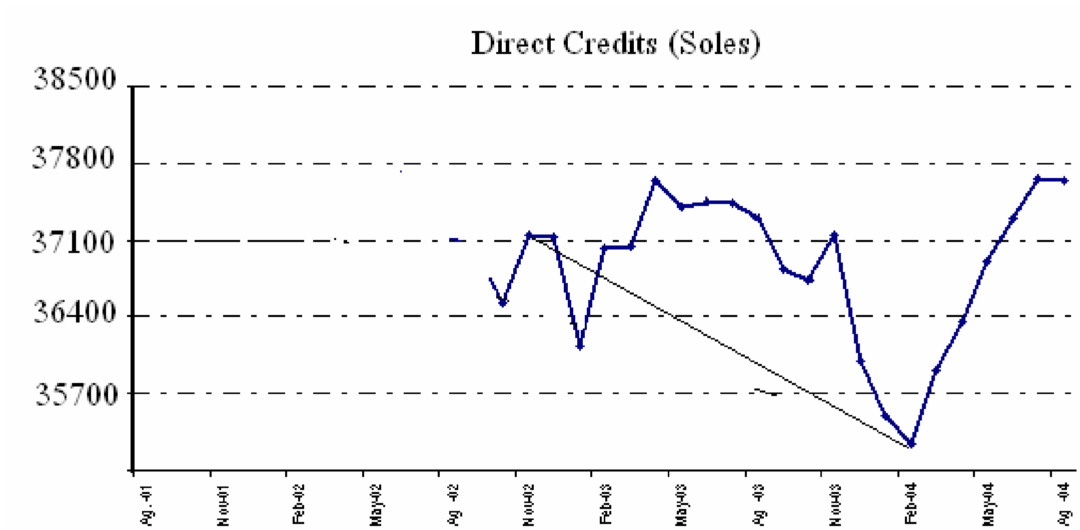
Source: IMF, World Economic Outlook.



Source: Peruvian Banking and Insurance Superintendence - Nov 2002 Statistics.

[13] Thailand crisis, July 1997; Russian Crisis August 1998; Brazil devalues and floats in February 1999; Turkey floats the lira in February 2001; Argentina defaults in December 2001 – Following the successive crises in Asia (1997) and Russia (1998).

14 The Unholy Trinity of Financial Contagion, by Kaminsky, Reinhart, and Vegh; Journal of Economics Perspectives – Volume 17-Number 4 – Fall 2003 - pg 63.



Source: Peruvian Banking and Insurance Superintendence - August 2004 Statistics.

2) Government policies pro-Camisea natural gas project and pro- natural gas-based electricity generation: The Peruvian Government had proven to be fickle in the past regarding the Camisea Project[15] as shown by its relationship with Shell - policies and acceptance towards the Camisea Project were highly dependent on the Presidential regime. However after the exit of Shell in July 1998, the successive governments have adopted a clear "pro-Camisea" position, granting a series of guarantees and incentives. The Project started constructions works in November 2002, thus it was affected by **Law 27133 – Law of Promotion of the Natural Gas Industry issued in June 4, 1999, in force as of today - after laws that have slightly modified it: DS 034-2001-EM (issued in July 2001), DS 018-2000-EM (issued in October 2000). The Project has also started construction after several incentives were already given and/or readily in place regarding promotion in the continuity of the Camisea gas project and in electricity generation based on natural gas - i.e. Take or Pay ("TOP") contract signed in December 2000.**

The Camisea chronology is the following:

a) During the Fujimori Regime (1990- August 2000): After the exit of Shell, in mid 1998, the Government decided to promote thermal technology based on natural gas, from that same year it halted the definitive and temporal concessions for hydropower plants through: Law 26980 issued in September 1998, Law 27133 issued in June 1999, and Law 27239 issued in December 1999[16]. No hydropower plants definite concessions were granted in the years 1999 to 2000[17], showing the clear impact and determination of the Fujimori's Laws against hydropower plants developments. In May 1999, the Special Committee for The Camisea Project (CECAM) called for an international public bid to award the license agreement for the Camisea Gas Exploitation, as well as the concession for liquids and gas transportation to the coast and gas fuel distribution in Lima and CalIao. In February 2000, pursuant to an international public bid, Fujimori's Government awarded the license for the exploitation of the Camisea Fields (Upstream) **to the Consortium Pluspetrol**, led by Pluspetrol Peru Corporation S.A (the operator), with

15 San Gaban II and Yuncan hydropower plants' constructions in 1998 show a no clear political promotion towards gas by that time of the Fujimori Government. These 2 hydroelectric power plants would produce daily the same as a natural gas-fired plant generation that uses 50 MMCFPD (almost the volume sell guaranteed under the Camisea Take or Pay contract). Between 1983 and 1987 as a result of drilling 5 exploration wells, Shell discovers the Camisea Gas Fields. In July 1998 the consortium Shell-Mobil announces its decision of abandoning the negotiations with Peruvian Government and, thus the contract is terminated.

16 The detail of these three laws against hydropower plant development can be seen under section A.4.4.

17 Source: Last-10-year list of definite concessions granted by the MINEM.

the participation of Hunt Oil Company of Peru L.L.C., SK Corporation and Tecpetrol del Peru S.A.C. (fully owned by Techint Group, an Argentinean group). The license was awarded based on the highest royalty rate offered[18] - The Upstream Project consists of a 40-year license for the extraction of natural gas and liquid hydrocarbon.

b) The Transitional Government of President Valentin Paniagua (set 2000-July 2001), derogated the Law 27239 Unique Complementary Disposition given by Fujimori against hydropower plant development through the Law 27435 (Hydropower Plants Concessions Promotions Law) in March 15th, 2001. But just months before the release of the issuance of Law 27435, in October 2000, the presidential regime had awarded the concessions for liquid and gas transportation to the coast and gas distribution in Lima and Callao (Downstream) **to The Consortium TGP**[19], led by Tecgas N.V (the operator and fully owned by Techint Group), with the participation of Pluspetrol Resources Corporation, Hunt Oil Company, SK Corporation, Sonatrach Petroleum Corporation B.V.I and Graña y Montero S.A. The Downstream includes three different 33-year contracts: a contract for the transportation of gas from

In December 2000, The Peruvian Government represented by Electroperu, stated owned generation enterprise, acquired an important commitment aiming at providing an extra incentive for The Camisea Project. This is the contract of supply of natural gas for electricity generation ("Take or Pay" or TOP). This contract indeed fostered this Mega Project, because it meant a commitment to pay close to $20 million annually for natural gas for electricity generation purposes regardless of whether it be consumed or not[20]. The TOP contract aimed at helping investors in Transportation and Distribution to achieve their projected IRR of 12%, the government also allowed an increase the regulated price to the final client, for this end. On the other hand, the scheme for the Extraction business was setting maximum prices of natural gas on-site (for the electricity sector: Max Price of 1.00 US$/MMBTU for other sectors: Max Price of 1.80 US$/MMBTU, for exports 0.6 US$/MMBTU to make it competitive internationally).

c) The current government of President Toledo (2001-2005), continues fostering thermal technology based on natural gas. In early in May, 2002, The Consortium TGP selected Tractebel as operator of the Gas Distribution Company[21]. Tractebel became a partner in the Consortium TGP (with 8% ownership). The gas distribution[22] concession in Lima and Callao was granted to the company Tractebel through a Built on Operate and Transfer ("BOT") Contract.

In August 2003, Electro Peru transferred the TOP contract to Etevensa, through public bid. This concession also committed Etevensa to sell its total energy generation to ElectroPeru at a relatively low price **($23.9 per MWh monthly for the first 7 years of contract)**, and committed Etevensa to an investment agenda in gas plants[23]. Etevensa consumption is estimated to be 70 MMCFPD, from which 80% (56 MMCF/D) would be under the TOP – Etevensa is allowed to reduce this volume by 10% to 50.4 MMCFPD.

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18 The consortium Pluspetrol offered the highest royalty rate, 37.24%.

19 Transportadora de Gas Del Peru S.A (TGP) is the company formed by the consortium specifically created for the development and peration of The Camisea Project Downstream.

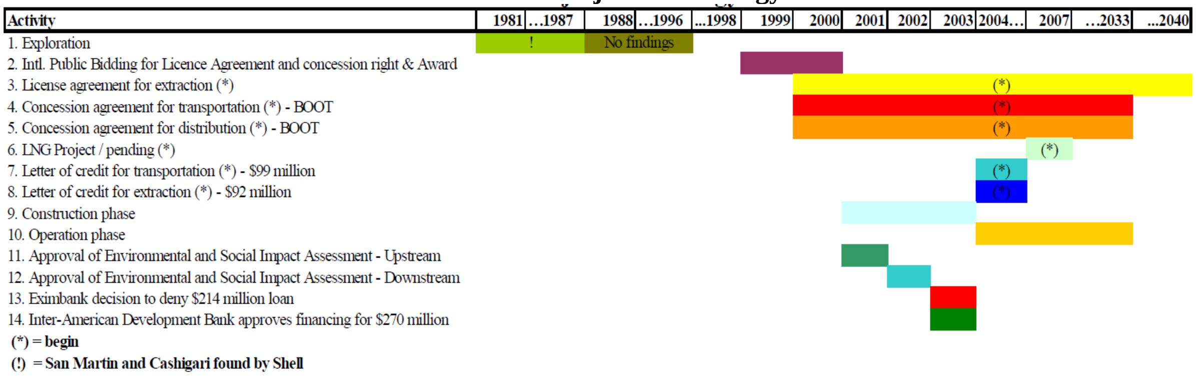
20 The TOP contract established a discount of 10% in the on−site price with respect to the price established for the other electric generators.

21 GNLC (Natural Gas of Lima and Callao) is a Tractebel-owned Company, created to develop the natural gas distribution service in Lima and Callao.

22 The distribution starts from the City Gate and goes to Ventanilla. Later on, the distributor (Tractebel) will have to construct additional pipelines of low and high pressure for industrial and commercial clients according to the increase in demand

23 Electro Peru transferred the Take or Pay contract to Etevensa, through public bid, the winner was conditioned to the installation of a 320 MW power plant: 2 gas turbine units of 125 MW each one and one steam unit of 62.5 MW. ETEVENSA, as the owner of the Ventanilla Thermal Plant, would use its 2 installed units of 160 MW (which it had to convert to be able to function with natural gas), and will add a steam 65 MW unit over by 2006. The government still holds a minority stake in such company.

The Camisea Project Chronology



Source: Own production with *MINEM* information

The impact of this government-driven project in electricity prices is devastating for hydropower developers which now have to compete not only with a cheaper technology available (combined cycle plants) , but also with a much cheaper national fuel.

The government has also announced in October 2004 its intention to promote a new 300-500 MW natural gas fired power plant. Furthermore, regulatory and economical incentives recently given by the Peruvian Government include the following laws, already present under section A.4.4 of the present document.

These laws directly promote electricity generation based on natural gas.

• **June 25, 2004: DS 019-2004,**
• **August 5, 2004: DS 107-2004-EF,**
• **November 24, 2004: DS 041-2004-EM.**

According to the *MINEM*[24], the foreseen Camisea impact scenarios[25] in the Peruvian electricity industry are two:

1) Hydro-thermal Scenario: At the end of 2027, the *SEIN* will have an installed capacity 66% thermal and 34% hydro. The current situation of the installed capacity of the *SEIN* is 40% thermal and 60% hydro.
2) Thermal Scenario: If all the additions in electricity generation were going to be natural gas-fired thermal plants, at the end of 2027 the SEIN would have an installed capacity 75% thermal and 25% hydro.

In both scenarios, the electric sector would be the main consumer of the Peruvian natural gas industry. In the hydro-thermal scenario the demand would be 800 MMCFPD, and in the thermal scenario would be 1000 MMMCFPD.

From this forecast it can be concluded that Peru's baseline in the future is Natural Gas.

Sub-step 3b. Show how the identified barriers would not prevent the implementation of at least one of the alternatives

-The still depressive International Investment Climate towards emerging markets when The Project started construction (Barrier 1):

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[24] *MINEM*-Electricity General Directive, http://www.minem.gob.pe/electricidad/estadisticas/informativo/informativo8.pdf

[25] Considering a 4.6% annual demand increase.

-Affected less strongly natural gas project developments (Alternative 2) because of three reasons:

- The lower investment needed to build a natural gas-fired power plant. A hydropower plant investment is needier of financing than a gas-fired power plant because of the much higher up-ront investment cost needed for the prior. The table below shows that the turnkey cost[26] per MW of a run-ofriver hydropower plant ($975,000) is more than double that of a simple cycle gas power plant ($475,000), on average.

Technology Comparison	Simple Cycle Gas Turbine	River Hydro
Size Range (MW)	0.5 - 450	.02 - 1
Efficiency (%)	21% - 45%	60-70%
Gen Set Cost ($/MW)	300,000 to 600,000	NA
Turnkey Cost-No Heat Recovery ($/MW)	**300,000 to 650,000**	**750,000 to 1,200,000**

Source: Meherwan P. Boyce, Ph.D, P.E (2002); "Gas Turbine Engineering Handbook", p.8

-The faster time it takes to put the brand-new engines in operation for the natural gas-fired power plant, which exposes lenders to less risk.

-The shorter time it takes in recovering the initial investment made which exposes lenders to less risk.

-Does not prevent "not implementing any power generation project" (Alternative 3), but in fact fosters it. Evidence of this is provided in the Newly Built 1998-2003 power plants table, shown under the Common Practice Analysis, in which it can be seen that the 3-year average of new capacity additions in the *SEIN* has decreased in 92% in the 3 most recent years (2001-2003) when compared with the previous three years (1998-2000)[27].

-Barrier due to prevailing practice (Barrier 2):

-Do not prevent the implementation of natural gas fired power plants (Alternative 2). In fact natural gas power fired plants is the beneficiary of all these policies and government interventions in the electricity market and energy sector from the second half of 1998.

-Do not impose penalties to "not investing"(Alternative 3), thus Alternative 3 is not prevented by Barrier 2 either.

Since the alternatives are affected less strongly/not prevented by the identified barriers that The Project faced, they are both viable alternatives and should not be eliminated from consideration.

Having been identified two barriers that prevented the implementation of this type of proposed project activity (hydropower plants) but did not prevent/affect less strongly at least one of the alternatives identified, the project is additional under Step 3.

Step 4. Common Practice Analysis

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[26] Turnkey meaning the investment needed to put a power plant in operation.

[27] Being the average annual capacity additions in 1998-2000, 275.87 MW, and 20.93 MW in 2001-2003.

Sub-step 4a. Analyze other activities similar to the proposed project activity
Hydro-generation barriers started in the second half of 1998 because of both 1) a depressed international investment climate towards emerging markets which has not favored highly capital intensive projects developments (as hydro are) access to financing, and 2) the determining governmental pro-Camisea position that started in 1998 after the exit of the Shell-Mobil. It is from the second half of 1998 that hydro development cannot be considered anymore common practice. The situation for hydro power plants projects has kept worsening, as long as more governmental guarantees have been offered to the Camisea Project. Although it can not be said that the emerging market conditions will not improve in the future, it can certainly be said that hydro development participation in power generation installed capacity will keep shrinking until 2027- based on *MINEM forecasts*, because of the Camisea Project occurrence.

All newly built hydropower plants that started operations from 1998 and all in-construction hydropower plants as of today, **except for CDM project activities** will be analyzed in this section.
In addition, gas projects (Alternative 2) and the no implementation of any electricity generation project (Alternative 3) will be discussed under this Sub-Step (4a.)

The List of electricity generation newly built plants from 1998 and in-construction projects in Peru is provided below:

In-construction projects (and their project generation by 2008[28])

Plants in construction	Situation	Additions in Installed Capacity (MW)	Technology	Estimated Annual Generation (GWh)
2004				
SANTA ROSA II	In construction	1.3	Hydro	6
VENTANILLA TG3	Conversion	164.1	Gas	697
VENTANILLA TG4	Conversion	160.5	Gas	1,440
2005				
YUNCAN	In construction	130	Hydro	909

Source: Own production with data of *GART* (4-year projections of May 2004) and *MINEM* projection for generation of Santa Rosa II

***SEIN* Capacity Additions from 1998 to 2003**

[28] Year in which annual generation of these projects stabilizes (especially that of the natural gas projects).

Years	Techn	Addition Category	Install.Cap. Added (MW)
1998			
AGUAYTIA 1	DRY GAS	Newly built	86.3
AGUAYTIA 2	DRY GAS	Newly built	86.3
TG MALACAS	PM GAS	Newly built	102.2
1999			
SAN GABAN II	HYDRO	Newly built	55.0
CALANA	R6	Newly built	6.4
MOLLENDO TGM	D2	Newly built	90.0
2000			
SAN GABAN II	HYDRO	Newly built	58.1
ILO2 TVC	COAL	Newly built	145.0
C.H. CHIMAY	HYDRO	Newly built	156.0
C.H. YANANGO	HYDRO	Newly built	42.3
2001			
TUMBES	R6	Newly built	18.3
2002			
C.H. HUANCHOR	HYDRO	Newly built	18.9
2003			
YARINACOCHA	R6	Newly Built	25.6

Source: Own production

Analyzing hydropower plants development (Alternative 1):
Newly built hydro power plant that started operation since 1998 cannot be considered common practice, but rather sporadic especial conditions of the projects' developers.

-Yuncan Project (will start operations in 2005):
TheYuncan Project recent sponsor: Tractebel, has planned to obtain CDM Status and is currently working on that process, a communication letter about this intention has been provided to the World Bank. However, as the application is not yet advanced this project will still be analyzed below:
The Yuncan Project, a 130 MW hydropower plant, was developed and fully owned by the Peruvian Government until June 2004. It started construction 1997, during the Fujimori Regime. The Financing for this project was given by an external loan granted to the Peruvian Government by the Japan Overseas Economic Cooperation Fund – OECF[29]. The total investment in the project accounts for $262.7 million. This project has been paralyzed for a number of years due to promotion of natural gas technologies and large cost overruns. On June 2004, the Government of Peru – in accordance with the local authorities of the Pasco region - granted to Enersur (Tractebel generation investment in Peru) a 30-year concession for the Yuncan hydropower plant and associated transmission facilities, keeping the same financial conditions for the new concessionary. The plant is currently under construction and is located in the Pasco Region, Central Peru, 340 km to the North East of Lima. The overall construction progress is 70% and the commissioning is estimated for July 2005. Under the usufruct agreement, Enersur has the exclusivity to operate the plant and sell the energy it generates. The financing is already given and will keep the same terms, this was a critical issue that motivated Tractebel to invest in this hydropower plant - Enersur's offer for Yuncan was approx. $53 million to be paid over the next seventeen months. Yuncan is not comparable to SINERSA for three reasons: **1) When the government started the construction of Yuncan the international climate was not depressed as it was in 2002, 2) also Camisea was not a major strategic target of the government by that time, and 3) For Yuncan, the government access to financing (1997) is the same access to financing enjoyed by Tractebel (2004) as the government continued being the guarantor for the loan of the OECF - This is not comparable to SINERSA's access to financing.**

[29] This institution lends only to governments, at very low interest rates.

-Santa Rosa II Project (has started operations in 2004):
Its application to obtain CDM Status is relevantly advanced, therefore this project will not be analyzed further. Santa Rosa II is a micro hydropower plant, 1.5 MW. Its sponsors applied to The World Bank to attain CDM status in early 2003. Application is **currently being processed as part of the Community Development Carbon Fund (CDCF) and Santa Rosa II will be treated as a small scale project.**

-Huanchor Hydropower plant (2002):
Huanchor (18.9 MW) started construction in 1999. It is owned by The *Grupo Gubbins*. The *Grupo Gubbins* is a large Peruvian investment group[30]. The sponsor purpose was to use hydro resources that were available close to its mines. Thus, the financial returns on that project were enhanced by savings in actual electricity expenses of the sponsors' mines (which consumes an important proportion of total Huanchor total generation). As natural gas was not available in the area surrounding the sponsor mines, the cheaper option was to build a hydropower plant. **Because of the synergies Huanchor provides to its sponsor, Huanchor is not comparable to The Project. SINERSA is also not financially comparable to the *Grupo Gubbins* regarding access to financing.**

-Chimay (2000) and Yanango (2000) Hydropower Plants:
Commonly called "Chinango", Chimay and Yanango account for 198.3 MW of installed capacity. The total investment was $200 million approx. The projects started constructions works in 1997, and were developed simultaneously by Edegel. Both are located approximately 125 miles east of Lima. The projects are separate facilities but do share a common transmission line, a new 120 kilometer, and a 220 kV line. This large investment was started just before the emerging markets crisis that strongly hit L.A from 1998[31] and in view of a good financial situation enjoyed by the sponsors, by 1997. Endesa Chile is a 37% Edegel shareholder. Enersis is a 60% Endesa-Chile shareholder, and Endesa-Spain is a 65% Enersis shareholder. Enersis' and Endesa's revenue for year 2003 were $3,998,967,000 and $20,899,871,000 respectively**. Both sponsors are not comparable to The Project's sponsor in access to financing, as of today, and they were certainly in a superior financial standing in 1997. Also the Chinango Project's sponsors enjoyed a better international investment climate in 1997 than SINERSA did in 2002. The Projects started construction works prior to pro-Camisea policies.**

-San Gaban II (1999, 2000) Hydropower Plant (2 units):
Units **developed and fully owned by the government** (as of today), the San Gaban II hydropower plant with an installed capacity of 113.1 MW[32] started its preliminary construction works in 1995. In May 1996, the civil works were called into a public bid. The winner was a Peruvian-Brazilian-French Consortium that **started civil works in September 1996** and took 3 years to finish them. San Gaban II was concluded in 1999. The external financing was $155 million approx., granted by The Japan Bank for International Cooperation ($130 million) and the CAF ($25 million). The total cost of this project was $208 million. San Gaban II, is currently under 100% ownership of the Peruvian Government through FONAFE (*Fondo Nacional de Financiamiento de la Actividad Empresarial del Estado*).

Discussing natural gas-fired power plants development (Alternative 2):
-Ventanilla TG3 and Ventanilla TG4 (2004):
Ventanilla TG3 and TG4 are the first plants built to use Camisea's natural gas, and are property of Etevensa; furthermore in May 2006, the gas combined cycled technology will be ready to operate in

[30] Which has stakes in Sociedad Minera Corona (assets of $36.06 Million up to June 2004), Sociedad Minera La Cima (assets for $19.8 Million up to June 2004) and Inversiones Agricolas S.A (asset information not publicly available).

[31] Russian crisis.

[32] Two units of approximately the same installed capacity.

Ventanilla TG4. These plants respond to Pro-Camisea governmental policies because Etevensa was committed to install a 320 MW gas-fired power installed capacity in order to win the transferal of Camisea's Take or Pay Contract from ElectroPeru[33].

-TG Malacas and Aguaytia 1 and 2 (1998):
These plants have been developed by the private sector, and by using the only two discovered gas wells in Peru besides Camisea. Although, they are not consequence of the Camisea circumstance, they show that gas per se is an attractive generation technology in Peru. The Aguaytia gas price does not differ greatly from the Camisea Gas price that is set for electricity generators consumers.

After the commercial operation of Ventanilla TG3 and TG4 in August 2004, it is foreseen that other large scale gas-fired power plants concessions requests will be presented to the *MINEM*.and granted[34];
Alternative 2 is plausible to become a common practice.

Discussing the no implementation of any power generation project (Alternative 3):
-In the Newly Built 1998-2003 power plants table shown above it can be seen that the 3-year annual average of new capacity additions in the *SEIN* has decreased in 92% in the 3 most recent years (2001-2003) when compared with the previous three years (1998-2000)47. This proves that the country can experience also scarcity in generation projects, in certain years; Alternative 3 although plausible in certain periods of time is not likely to become a common practice because of market forces.

Sub-step 4b. Discuss any similar options that are occurring:
No similar activities (hydropower plants) in terms of access to financing, international investment climate or developed under the same clear governmental pro-Camisea position have been identified from 1998.
The only hydro power plant development that can be comparable to The Project in regards to depressed international investment climate and starting construction after the clear pro- Camisea governmental position is Huanchor, but this project activity has essential distinctions with The Project, these distinctions have been analyzed in Sub-step 4a.

Since similar activities (hydropower plants) have essential distinctions with the project activity that can reasonably be explained and were exposed under Sub-Steps 4a and 4b, the claim that the proposed activity is common practice is not called into question. Therefore, The Project is not common practice but a very unusual occurrence that endangered its existence without attaining CDM Status. Meaning The Project is additional under Step 4.

<u>Step 5. Impact of CDM Registration</u>
CDM registration will alleviate the financial hurdles of The Project (**Step 2. Investment analysis)** since it would provide risk-free revenue[35], attached to The Project's annual generation. If CERs revenues are used to offset The Project's O&M annual costs, The Project's levelized cost will decrease and so will the Project's financial unattractiveness. The Sponsor considered, before the Project investment decision was made[36] the potential impact of CDM Registration very important for The Project's financial viability due to the CERs potential high liquidity in the international market. At that point in time, there was an even higher uncertainty in the future CERs price.

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[33] The TOP is mentioned under Step 3 Barrier Analysis (Sub-Step 3.a.) faced by The Project

[34] Tractebel's request of 360 MW approximately installed capacity and EGECHILCA's request of 520 MW approximately installed capacity are two of the most publicly known concession requests already made to *MINEM*.

[35] Except for the CDM risk.

[36] As stated in a Sponsor's Board of Directors act signed as of April 2002 - made available to the DOE.

As of today, taking a credible CERs price of $5.63 per tCO2e - which is the weighted average CERs price between January 2004 and April 2005[37] - CERs revenues could reduce The Project's financial gap (difference between The Project levelized cost and The *SEIN* LRMC) in 18%, going from a $17.85/MWh[38] to $14.56/MWh[39]-almost one fifth down of the financial gap the project faced without CERs revenues.

Price (US$) 5.63

SENSITIVITY ANALYSIS FOR THE PROJECT LEVELIZED COST ($/MWh)

40 years of payment 16.9 Investment Cost 14% Discount Rate		LF=43.36%	+ CERs 7 years	+ CERs 14 years	+ CERs 21 years
Capacity	MW	15.2	15.2	15.2	15.2
Cost	$/KW	1,097	1,097	1,097	1,097
Total Investment	$Million	16.9	16.9	16.9	16.9
Annual Cost:					
Income CERS	$Million	$0.00	($0.12)	($0.17)	($0.19)
Capital	$Million	$2.38	$2.38	$2.38	$2.38
O&M	$Million	0.225	0.225	0.225	0.225
Total Annual Cost	$Million	$2.60	$2.48	$2.43	$2.41
Plant Factor	%	43.36%	43.36%	43.36%	43.36%
Generation	MWh	57,740	57,740	57,740	57,740
Levelized Cost	**$/MWh**	**45.09**	**42.98**	**42.14**	**41.80**
CERs/yr (tCO2)	**31,463**	**Change in $/MWh:**	**-4.68%**	**-6.55%**	**-7.30%**
Revenue/yr ($)	**177,137**				

CER 7 years	PV of Revenue	$865,962
	Equivalent Annual Revenue	$121,880
	In millions	$0.12
CER 14 years	PV of Revenue	$1,212,033
	Equivalent Annual Revenue	$170,588
	In millions	$0.17
CER 21 years	PV of Revenue	$1,350,336
	Equivalent Annual Revenue	$190,053
	In millions	$0.19

Source: Single parameters were provided by the Sponsor, calculations are own production.

Depending on future CERs price, the impact of carbon finance on the financial viability of the project could be even greater. i.e. Upon registration and promptly CERs sell in the EU ETS, as long as issues that explain the difference between the CERs price and the currently higher EUA price are overcome[40], The
Project's CERs from the start of its crediting period (April 2004) up to December 2007 could achieve a higher-than-$5.63 price, reducing the project financial gap in a greater percentage.

Moreover, CDM registration also alleviates the barriers faced by The Project **(Step 3. Barrier analysis)**.

A still depressive International Investment Climate towards emerging markets when The Project started construction (Barrier 1) that impeded funding is alleviated when CDM registration is achieved. When CDM registration is achieved the Sponsor could discount or borrow against CERs revenues at a low interest rate[41]. The Sponsor is currently evaluating this possibility to satisfy its own cash flow commitments.

Government policies pro-Camisea natural gas project and pro-natural gas based electricity generation (Barrier 2) will be alleviated. CERs revenues will allow The Project to better compete with more efficient technologies available in the country (open cycle and combined cycle Camisea-natural-gas-based electricity generation), and also to better manage the lower electricity market price-consequence of the incorporation of more efficient technologies to the system. The CERs revenue could also offset the fiscal incentives given by the Peruvian government to natural gas-fired power projects/plants (i.e. Selective Consumption Tax exemption for the gas).

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[37] International Emissions Trading Association and The World Bank Carbon Finance Business (Washington DC, May 2005) - State and Trends of Carbon Market 2005, Page 4.

[38] 45.09 minus $27.24.

[39] $41.80 minus $27.24, for a CERs revenues stream of 21 years.

[40] Delivery risk from 2005-2007, uncertainty related to technical aspects of the import of CERs into the EU ETS, among others. These and further
explanations of the difference in EUA and CER prices are stated by: International Emissions Trading Association and The World Bank Carbon Finance Business (Washington DC, May 2005) - State and Trends of Carbon Market 2005, Page

[41] Given that this revenue streams has CDM risk only.

Since the approval and registration of The Project as a CDM activity alleviate the economic and financial hurdles (Step 2) and other identified barriers (Step 3) to a reasonable extent, it is concluded that The Project is additional under Step 5.

Because all of the above steps were satisfied, the CDM Project activity is not the baseline scenario, meaning The Project is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

According to the "Tool to assess the validity of the original/current baseline and to update the baseline at the renewal of a crediting period", data and parameters that were only determined at the start of the crediting period and not monitored during the crediting period should be updated.
As is seen as follows, the application of steps 1.1, 1.2 and 1.4 of the Tool, confirmed that the baseline, data and parameters can be used for the renewal crediting period.

The emission reduction (ER_y) for the Project:

According to methodology ACM0002 (version 12.1), the emission reduction *ER y* by the project activity during a given year *y* is calculated as follows:

ERy = BEy – PEy

Where:
ER_y = Emission reductions in year *y* (t CO_{2e}/yr)
BE_y = Baseline emissions in year *y* (t CO_{2e}/yr)
PE_y = Project emissions in year *y* (t CO_{2e}/yr)

Project Emissions

According to the consolidated approved methodology ACM0002 version 12.1.0 project emissions for this project are zero since the project is a hydropower plant with existing reservoir where the volume of the reservoir is not increased.

Baseline emissions

According consolidated approved methodology ACM0002 version 12.1.0, 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:

$$BE_y = EG_{PJ,y} \cdot EF_{grid,CM,y} \qquad \textbf{(1)}$$

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)

<u>Calculation of $EG_{PJ,y}$</u>

Since the project activity is the installation of a new 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:

$$EG_{PJ,y} = EG_{facility,y} \quad \textbf{(2)}$$

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 year *y* (MWh/yr)

The Baseline emission factor is calculated as a combined margin ($EF_{grid,CM,y}$) , following the guidance in the *Tool to calculate the emission factor for an electricity system, Version 02*.2.1 According to the *Tool*, the baseline emission factor is calculated as the weighted average of the Operating Margin emission factor ($EF_{grid,OM,y}$) and the Build Margin emission factor ($EF_{grid,BM,y}$) where the weights w_{OM} and w_{BM}, by default, are 50% (i.e., $w_{OM} = w_{BM} = 0.5$). This is presented below:

Estimated anthropogenic emissions were calculated for the Project following a 6-step-process:

Step 1: Identify the relevant electricity systems.
Step 2: Choose whether to include off-grid power plants in the project electricity system (optional)
Step 3: Select a method to determine the operating margin (OM)
Step 4: Calculate the operating margin emission factor according to the selected method
Step 5: Calculate the build margin (BM) emission factor
Step 6: Calculate the combined margin emissions factor

Step 1. Identify the relevant electricity systems

The power plant is connected to the national grid through a 60 kV overhead transmission line. The transmission line has a length of 38-km and is connected to the existing Sullana substation - which belongs to Electronoroeste S.A. (ENOSA).

Electricity imports or exports from other grid have been neither reported by the SEIN dispatch center of nor the Ministry of Energy and Mines.

If it would be the case, for the purpose of determining the operating margin emission factor, it will be assumed a CO_2 emission factor(s) for net electricity imports 0 tCO_2/MWh;

Electricity exports should not be subtracted from electricity generation data used for calculating and monitoring the electricity emission factors.

Step 2: Choose whether to include off-grid power plants in the project electricity system (optional).

Project participants may choose between the following two options to calculate the operating margin and build margin emission factor:

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

Option II: Both grid power plants and off-grid power plants are included in the calculation.

Since project participants considered only grid power plants for the calculation of the operating margin and build margin emission factor, Option one is selected.

Step 3: Select a method to determine the operating margin (OM)

The calculation of the Operating Margin emission factor(s) ($EF_{grid,OM,y}$) is calculated based on one of the four following methods, which are described under step 4:

(a) Simple OM, or
(b) Simple adjusted OM, or
(c) Dispatch Data Analysis OM, or
(d) Average OM.

Out of four options for the OM, the Dispatch Data Analysis OM (OM-DD) was selected. The Simple OM method cannot be used since low cost, must-run resources constitute more than 50% of total grid generation in Peru. Also, it was not necessary to use either the Simple Adjusted OM approach or the Average OM approach because detailed dispatch data is available.

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

The formula for the OM-DD emission factor ($EF_{grid,OM-DD,y}$) used was provided by the tool as follows:

$$\mathbf{EF_{grid,OM\text{-}DD,y} = \sum_h EG_{PJ,h} * EF_{EL,h} / EG_{PJ,y}}$$

Where,

$EF_{grid,OM-DD,y}$	=	Dispatch data analysis operating margin CO_2 emission factor in year y (tCO_2/MWh)
$EG_{PJ,h}$	=	Electricity displaced by the project activity in hour h of year y (MWh)
$EF_{EL,DD,h}$	=	CO_2 emission factor for grid power units in the top of the dispatch order in hour h in year y (tCO_2/MWh)
$EG_{PJ,y}$	=	Total electricity displaced by the project activity in year y (MWh)
h	=	Hours in year y in which the project activity is displacing grid electricity
y	=	Year in which the project activity is displacing grid electricity

Since hourly fuel consumption data is not available, the hourly emissions factor is determined based on the energy efficiency of the power unit and the fuel type used, as follows

$EF_{EL,DD,h} = \sum_n \mathbf{EG_{n,h}} \times \mathbf{EF_{EL,n,y}} / \sum_n \mathbf{EG_{n,h}}$

Where:

$EF_{EL,DD,h}$ = CO_2 emission factor for grid power units in the top of the dispatch order in hour h in year y (tCO_2/MWh)

$EG_{n,h}$ = Net quantity of electricity generated and delivered to the grid by grid power unit n in hour h (MWh)

$EF_{EL,n,y}$ = CO_2 emission factor of grid power unit n in year y (tCO_2/MWh)

n = Grid Power units in the top of the dispatch.

At each hour h, stack each grid power unit's generation using the merit order. The group of power units n in the dispatch margin includes the units in the top x% of total electricity dispatched in the hour h, where x% is equal to the greater of either:

(a) 10%; or

(b) The quantity of electricity displaced by the project activity during hour h divided by the total electricity generation in the grid during that hour h.

h = Hours in year y in which the project activity is displacing grid electricity

The $EF_{EL,n,y}$ is calculated as per the guidance for the simple OM, using the option A2.

$\mathbf{EF_{EL,m,y} = (EFco_2,m,i,y*3.6)/(\eta m,y).}$

Where:

$EF_{EL,m,y}$ = CO_2 emission factor of power unit m in year, y (tCO2/MWh)
$EF_{CO2,m,i,y}$ = Average CO_2 emission factor of fuel type, i, used in power unit m in year, y (tCO_2/GJ)
$\eta_{m,y}$ = Average net energy conversion efficiency (NEC)of power unit, m, in year, y, (%)
m = All power units serving the grid in year y except low-cost/must-run power units
y = applicable year during monitoring (ex-post option)

Where several fuel types are used in the power unit, use the fuel type with the lowest CO_2 emission factor for $EFCO_{2,m,i,y.}$

Step 5. Identify the group of power units to be included in the BM

In terms of vintage of data, project participants have chosen option 2: For the second crediting period, the build margin emission factor is calculated ex ante based on the most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation.

According to the Tool, the sample group of power units m used to calculate the build margin should be determined as per the following procedure, consistent with the data vintage selected above:

(a) Identify the set of five power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently (SET5-units) and determine their annual electricity generation ($AEG_{SET\text{-}5\text{-}units}$, in MWh);

(b) Determine the annual electricity generation of the project electricity system, excluding power units registered as CDM project activities (AEG_{total}, in MWh). Identify the set of power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently and that comprise 20% of AEG_{total} (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation) ($SET_{\geq 20\%}$) and determine their annual electricity generation ($AEG_{SET\text{-}\geq 20\%}$, in MWh);

(c) From $SET_{5\text{-}units}$ and $SET_{\geq 20\%}$ select the set of power units that comprises the larger annual electricity generation (SET_{sample});

Identify the date when the power units in SET_{sample} started to supply electricity to the grid. If none of the power units in SET_{sample} started to supply electricity to the grid more than 10 years ago, then use SET_{sample} to calculate the build margin. Ignore steps (d), (e) and (f).

Otherwise:

(d) Exclude from SET_{sample} the power units which started to supply electricity to the grid more than 10 years ago. Include in that set the power units registered as CDM project activity, starting with power units that started to supply electricity to the grid most recently, until the electricity generation of the new set comprises 20% of the annual electricity generation of the project electricity system (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation) to the extent is possible. Determine for the resulting set ($SET_{sample\text{-}CDM}$) the annual electricity generation ($AEG_{SET\text{-}sample\text{-}CDM}$, in MWh);

If the annual electricity generation of that set is comprises at least 20% of the annual electricity generation of the project electricity system (i.e. $AEG_{SET\text{-}sample\text{-}CDM} \geq 0.2 \times AEG_{total}$), then use the sample group $SET_{sample\text{-}CDM}$ to calculate the build margin. Ignore steps (e) and (f).

Otherwise:
(d) Exclude from SET_{sample} the power units which started to supply electricity to the grid more than 10 years ago. Include in that set the power units registered as CDM project activity, starting with power units that started to supply electricity to the grid most recently, until the electricity generation of the new set comprises 20% of the annual electricity generation of the project electricity system (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation) to the extent is possible. Determine for the resulting set ($SET_{sample\text{-}CDM}$) the annual electricity generation ($AEG_{SET\text{-}sample\text{-}CDM}$, in MWh);

If the annual electricity generation of that set is comprises at least 20% of the annual electricity generation of the project electricity system (i.e. $AEG_{SET\text{-}sample\text{-}CDM} \geq 0.2 \times AEG_{total}$), then use the sample group $SET_{sample\text{-}CDM}$ to calculate the build margin. Ignore steps (e) and (f).

Otherwise:

(e) Include in the sample group $SET_{sample\text{-}CDM}$ the power units that started to supply electricity to the grid more than 10 years ago until the electricity generation of the new set comprises 20% of the annual electricity generation of the project electricity system (if 20% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation);

(f) The sample group of power units m used to calculate the build margin is the resulting set ($SET_{sample\text{-}CDM\text{->}10yrs}$).

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:

$$\mathbf{EF_{grid\ BMy} = [\textstyle\sum_m EG_{,m,y,}\ x\ EF_{EL,m,y}] / [\sum_m EG_{my}]}$$

Where:

$EF_{grid,BM,y}$	=	Build margin CO_2 emission factor in year, *y* (tCO_2/MWh)
$EG_{m,y}$	=	Net quantity of 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

The CO_2 emission factor of each power unit *m* ($EF_{EL,m,y}$) should be determined as per the guidance in Step 4 (a) for the simple OM, using option A2, using for *y* the most recent historical year for which power generation data is available, and using for *m* the power units included in the build margin.

If the power units included in the build margin *m* correspond to the sample group $SET_{sample\text{-}CDM\text{->}10yrs}$, then, as a conservative approach, only option A2 from guidance in Step 4 (a) can be used and the default values provided in Annex 1 shall be used to determine the parameter $\eta_{m,y}$.

Step 6. Calculate the combined margin (CM) emissions factor.

The calculation of the combined margin (CM) emission factor ($EF_{grid,CM,y}$) is based on one of the following methods:

(a) Weighted average CM; or
(b) Simplified CM.

The weighted average CM method (option A) is used.

(a) Weighted average CM

The combined margin emissions factor is calculated as follows:

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

Where:

$EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year, *y* (tCO_2/MWh)

$EF_{grid,OM,y}$ = Operating margin CO_2emission factor in year, *y* (tCO_2/MWh)

W_{OM} = Weighting of operating margin emissions factor (%)

W_{BM} = Weighting of build margin emissions factor (%)

The following default values should be used for W_{OM} and W_{BM}:

W_{OM} = 0.5 and W_{OM} = 0.5 for the first crediting period, and W_{OM} = 0.25 and W_{OM} = 0.75 for the second and third crediting period.

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

Data / Parameter:	**$EF_{grid\ BMy}$**
Data unit:	tCO_2/MWh
Description:	Build margin CO_2 emission factor in year y (tCO_2/MWh) calculated using the latest version of the “Tool to calculate the emission factor for an electricity system”
Source of data used:	Calculated based in COES annual statistics. The last one was published in year 2009. The calculation is in spreadsheet “Poechos I BM2 2009.xls”
Value applied:	0.50665tCO_2/MWh
Justification of the choice of data or description of measurement methods and procedures actually applied :	The build margin emission factor is calculated ex ante based on the most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation. Steps necessary to find the Build margin CO_2 emission factor are found in the “Tool to calculate the emission factor for an electricity system”
Any comment:	

B.6.3. Ex-ante calculation of emission reductions:

<u>Project Emissions</u>

The Project does not lead to any GHG emissions since Poechos I is a hydropower plant with existing reservoir where the volume of the reservoir is not increased, then. Hydropower plants without reservoirs are classified as zero emission projects, for which there are no associated emissions in the Project boundary.

Baseline emissions

The baseline emissions are calculated as follows:

The baseline emission factor was calculated prior validation in a transparent and conservative manner as a combined margin (CM) consisting of the average of the operating margin (OM) and the build margin (BM), according to the procedures prescribed in the Tool to calculate the emission factor for an electricity system, Version 02.2.1, and explained in section B.6.1.

Since the Project itself does not lead to any GHG emissions and no leakage[42] was factored into the calculation of estimated ERs, the baseline emissions were estimated to be equal to the Project ERs.

Combined Margin Calculation

Step 1. Identify the relevant electricity systems.

The power plant is connected to the national grid through a new 60 kV overhead transmission line. The transmission line has a length of 38-km and is connected to the existing Sullana substation - which belongs to Electronoroeste S.A. (ENOSA).

Electricity imports or exports from other grid have been neither reported by the SEIN dispatch center of nor the Ministry of Energy and Mines.

Step 2. Choose whether to include off-grid power plants in the project electricity system (optional).

Since project participants considered only grid power plants for the calculation of the operating margin and build margin emission factor, Option one is selected.

Step 3: Select a method to determine the operating margin (OM)

Out of the four options for the OM, the Dispatch Data Analysis OM (OM-DD) was selected. The Simple OM method cannot be used since low cost, must-run resources constitute more than 50% of total grid generation in Peru. Also, it was not necessary to use either the Simple Adjusted OM approach or the Average OM approach because detailed dispatch data is available.

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

Since the year in the project goes from April 1 to March 31, the last year previous to the renowal is April 1, 2009 to March 31, 2010. Therefore, for the calculation of the operating margin it has been used the hourly generation for the period April 1, 2009 to March 31, 2010 . For ex ante calculations, it was used as a reference the real electricity production of the project for this period.

Considering this, the variables were defined as follows:

[42] Since the energy generating equipment is new and is not replacing any existing facility, the Project does not produce leakage.

[24]Source COES,Annual Statistics 2010. Page 73

- $EG_{PJ,y}$: Total electricity generated by the Project in the period April 1, 2009 to March 31, 2010. It was used real production of the project for that year.
- $EG_{PJ,h}$: Total electricity generated by the Project in each hour of the period April 1, 2009 to March 31, 2010 . It was used real data of that year.

The following chart shows the $EF_{EL,n,y}$ of the all thermal units of the SEIN (National Grid) each emission factor has been calculated as per the guidance for the simple OM, using the option A2.

$EF_{EL,n,y}$ of the all thermal units of the SEIN

Code	Thermal Plant	Technology	CO_2 emission factor tCO_2/MWh
ag_tg1	AGUAYTIA 1 (2)	Natural Gas	0.60
ag_tg2	AGUAYTIA 2 (2)	Natural Gas	0.60
bvista1	BELL MAN 1,2	Diesel 2	0.90
bvista2	BELL MAN 1,2	Diesel 2	0.90
calana123	CALANA 123	Residual 6	0.67
calana4	CALANA 4	Residual 6	0.67
ccomb	C. COMBINADO	Diesel 2 CC	0.89
chi_slz12	SULZER CHILINA	Diesel 2	0.90
chicl_o	DS CHICLAYO OESTE-D	Diesel 2	0.90
chiltv1	chiltv1	R500	0.84
chiltv2	TV2 CHILINA	R500	0.84
chiltv3	TV3 CHILINA	R500	0.84
chimb	TG1 CHIMBOTE	Diesel 2	0.90
cnp_mann	DS PACAS-MAN	Residual 6 and Diesel 2	0.71
cnp_slz	DS PACAS-SULZER	Residual 6	0.67
dolores1	DOL ALCO 1-2 GM 1-2-3	Diesel 2	0.90
dolores2	DOL ALCO 1-2 GM 1-2-3	Diesel 2	0.90
ilo1catk	KATCATO (ENERSUR)	Diesel 2	0.90
ilo1tg1	TG1 ILO	Diesel 2	0.90
ilo1tg2	TG2 ILO	Diesel 2	0.90
ilo1tv1	ILO TV1	R500	0.84
ilo1tv2	ILO TV2	R500	0.84
ilo1tv3	ILO TV3	R500	0.84
ilo1tv4	ILO TV4	R500	0.84
ilo2_carb	TV CARBON ILO II	Coal	0.78
mal_tg1	TG1	Natural Gas	0.60
mal_tg2	TG2	Natural Gas	0.60
mal_tg3	TG3	Natural Gas	0.60
mal_tg4	TGN4	Natural Gas	0.60
moll123	MOLLENDO 1,2,3	R500	0.84
molltg1	TGM1 MOLLENDO	Diesel 2	0.90
molltg2	TGM2 MOLLENDO	Diesel 2	0.90
moq12	MOQUEGUA	Diesel 2	0.90
paita1	DS PAITA1	Diesel 2	0.90
paita2	DS PAITA2	Diesel 2	0.90
piura1	DS PIURA1	Diesel 2	0.90
piura2	DS PIURA2	Diesel 2	0.90
shcummins	CUMMINS	Diesel 2	0.90
shou_tv1	TV1 SHOUGESA	R500	0.84
shou_tv2	TV2 SHOUGESA	R500	0.84
shou_tv3	TV3 SHOUGESA	R500	0.84
sullana	DS SULLANA	Diesel 2	0.90
taparachi	TAPARACHI	Diesel 2	0.90
tg_piu	TG PIURA	Diesel 2	0.90
tintaya	TINTAYA	Diesel 2	0.90
tp55	Chilca1	Natural Gas	0.60
tp56	Kallpa TG1	Natural Gas	0.60
tp57	Oquendo	Natural Gas	0.60
tp58	Chilca3	Natural Gas	0.60
tp59	CT Santa Rosa TG8	Natural Gas	0.60
tp60	CT Emerg Trujillo	Diesel 2	0.90
tp61	Ventanilla Vapor	Natural Gas CC	0.39
tp62	CT Paramonga	Biomasa	0.00
tp63	TP63	Unknown	0.00
tp64	TP64	Unknown	0.00
tp65	TP65	Unknown	0.00
tp66	TP66	Unknown	0.00
truji	TG TRUJILLO	Diesel 2	0.90
trupal	TRUPAL	Residual 6	0.67
tumbes	TUMBES	Residual 6	0.67
uti_5	TG S.ROSA UTI5	Diesel 2	0.90
uti_6	TG S.ROSA UTI6	Diesel 2	0.90
vent3	TG VENTANILLA-3	Diesel 2	0.90
vent4	TG VENTANILLA-4	Diesel 2	0.90
westin	TG WESTINGHOUSE	Diesel 2	0.90
yarinac	Yarinacocha (5)	Residual 6	0.67

Calculation EF_{EL}s:

COEF(tCO2/MWh)	Open Cycle					Combined Cycle	
Type of Fuel	**D2**	**R6**	**R500**	**Natural gasGas**	**Coal**	**D2**	**Natural Gas**
NEC	29.02%	40.32%	32.47%	32.84%	40.20%	29.30%	50.50%
EF_{CO2} (tCO2/Gigajoule)	0.0726	0.0755	0.0755	0.0543	0.0873	0.0726	0.0543
COEF(tCO2/MWh)	**0.90**	**0.67**	**0.84**	**0.60**	**0.78**	**0.89**	**0.39**

Source for NECs: Average NECs per technology. NEC per plant is available in COES annual statistics 2009 page 35 Chart No.4.7.

Source of EF_{CO2}: IPCC 2006 default values at the lower limit of uncertainty at a 95% confidence interval as provided in table 1.4 of chapter 1 of vol 2(Energy) of the 2006 IPCC Guidelines on National GHG inventories.

Information on the hourly generation of all plants in the SEIN[43] and their associated emission factors was entered using Excel software and organized in columns where the position of the columns was determined by the yearly grid dispatch merit order[44]. This process enabled identification of the plants that fall within the top x % of grid dispatch each hour of the year. In the prior to validation calculations, the quantity of electricity displaced by the project activity during hour h divided by the total electricity generation in the grid during that hour h is smaller than 10% so 10% is used to determine the plants that fall within the top x % of grid dispatch each hour of the year

The resulting DDA-OM emission factor was calculated as follows:

$$EF_{grid,OM\text{-}DD,y} = \sum_h EG_{PJ,h} * EF_{EL,h} / EG_{PJ,y} = 67,123/88,811.30 = 0.75579 \ tCO_2/MWh$$

Step 5: Calculate the built margin (BM) emission factor

In terms of vintage of data, project participants have chosen option 2: For the second crediting period, the build margin emission factor is calculated ex ante based on the most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation.

Capacity additions from retrofits of power plants should not be included in the calculation of the build margin emission factor.

Table below shows the capacity additions to the SEIN, and their annual generation. The annual generation of the additions included in this table for ex-ante calculations is from 2009, which is the latest year that information was publicly available.

Capacity Additions in the SEIN (2006-2009)

Plant	Date	Technology	Installed Capacity Added (MW)	2009 total production in GWh
Santa Rosa TG8	August 2009	Gas turbine Natural Gas	199.83	42.96
TG31Chilca	July 2009	Gas turbine Natural Gas	194.19	412.18
TG2 Kallpa	June 2009	Gas turbine Natural Gas	193.52	503.69
Trujillo Norte	June 2009	Diesel 2	62.13	83.34
Oquendo	January 2009	Gas turbine Natural Gas	29.38	187.44
TG21Chilca	July 2007	Gas turbine Natural Gas	174.53	1,144.14
TG1 Kalpa	July 2007	Gas turbine Natural Gas	174.41	734.24
TG11 Chilca	December 2006	Gas turbine Natural Gas	175.96	996.14
Ventanilla cc	October 2006	Gas turbine Natural Gas	492.75	3,256.21
Santa Rosa UTI 5 y 6	August 2006	Gas turbine Natural Gas	106.02	158.14

Source: COES

In Table below, it can be seen that the 5 most recently built ($SET_{5\text{-units}}$) plants up to year 2009 were: 1) Santa Rosa TG8, 2) TG3 Chilca, 3) TG 2 Kallpa, 4) Trujillo Norte, 5) Oquendo, with their total annual generation being 1,230 GWh ($AEG_{SET\text{-}5\text{-units}}$).

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[43] Data provided by COES (The dispatch centre)
[44] This was done by the merit orders assigned to each unit of the SEIN, as published by COES in its annual statistics

On the other hand, the total annual generation of the most recently built plants ($SET_{\geq 20\%}$) accounting for 20 % of the grid was higher 7,360GWh ($AEGSET_{\geq 20\%}$), therefore, the most recently built plants accounting for 20 % of the grid was selected for the BM calculation.

Selection of SET_{sample} power plants

Year	Plant Name	Plant Type	Most recent year generation(GWh)	Filter most recent 20%	$AEG_{SET-\geq 20\%}$, MWh	Filter 5 most recent units	$AEG_{SET-5-units}$ MWh
August 2009	Santa Rosa TG8	Gas turbine Natural Ga	42.96	**1**	42.96	**1**	43
July 2009	TG31Chilca	Gas turbine Natural Ga	412.18	1	412.18	1	412
June 2009	TG2 Kallpa	Gas turbine Natural Ga	503.69	1	503.69	1	504
June 2009	Trujillo Norte	Diesel 2	83.34	1	83.34	1	83
January 2009	Oquendo	Gas turbine Natural Ga	187.44	1	187.44	1	187
July 2007	TG21Chilca	Gas turbine Natural Ga	1,144.14	1	1,144.14		
July 2007	TG1 Kalpa	Gas turbine Natural Ga	734.24	1	734.24		
December 2006	TG11 Chilca	Gas turbine Natural Ga	996.14	1	996.14		
October 2006	Ventanilla cc	Gas turbine Natural Ga	3,256.21	1	3,256.21		
					-		
			-		-		
			-		-		
			-		-		
			-		-		
			-		-		
			-		-		
			-		-		
			-		-		
T/.			7,360	9	7,360	5	
					24.69%		1230
				AEG_{total}=	**29,807**		
				$AEG_{SET-\geq 20\%}$, n=	**5,961**		

$AEG_{SET-\geq 20\%}$,		$AEG_{SET-5-units}$
7,360	>	1,230

In Table below, the selected sample of most recently built plants was organized by their annual electricity generation output, , and their emission factors. By calculating the generation-weighted average emission factor (tCO_2/MWh) of the selected sample , the build margin emissions factor was obtained. The resulting **BM2** equals **0.50665 tCO_2/MWh** for the year 2009.

BM Calculation

Plant Name	Most Recent Year Gen (GWh)	% per plant	CO2 emission Factor tCO2/MWh	BM Calculation
Santa Rosa TG8	43	0.58%	0.595	**0.0035**
TG31Chilca	412	5.60%	0.595	**0.0333**
TG2 Kallpa	504	6.84%	0.595	**0.0407**
Trujillo Norte	83	1.13%	0.901	**0.0102**
Oquendo	187	2.55%	0.595	**0.0152**
TG21Chilca	1,144	15.54%	0.595	**0.0925**
TG1 Kalpa	734	9.98%	0.595	**0.0594**
TG11 Chilca	996	13.53%	0.595	**0.0806**
Ventanilla cc	3,256	44.24%	0.387	**0.1712**
Total	7,360	100%		**0.50665**
				BM for year 2009

BM2=	**0.50665**	**tCO2//MWh**

Step 6. Calculate the combined margin (CM) emissions factor.

The Baseline Emission Factor was calculated as a CM, which is the weighted average[45] of the OM and the BM. All margins are expressed in tCO_2/MWh.

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times 0.25 + EF_{grid,BM,y} \times 0.75$$

$$EF_{grid,CM,y} = 0.25*(0.75579) + 0.75*(0.50665) = 0.56893\ tCO_2/MWh$$

The resulting Baseline Emission Factor is 0.56893 tCO_2/MWh.

Calculation of the Project's Emission Reductions Prior to Validation

Since the Project itself does not lead to any GHG emissions and no leakage[46] was factored into the calculation of estimated ERs, the baseline emissions were estimated to be equal to the Project ERs

The estimated annual ERs for the Project were calculated as follows:

ERy = BEy – PEy

Where:

ER_y = Emission reductions in year *y* (t CO_2e/yr)
BE_y = Baseline emissions in year *y* (t CO_2/yr)
PE_y = Project emissions in year *y* (t CO_2e/yr)

BEy = $(EG_{pj,y})*EF_{grid,CM,y}$

BEy = **57,740** MWh* **0.56893** tCO_2/MWh * = **32,850 tCO_2**

PEy = Zero

Estimated Emission Reductions:

ERy = BEy – PEy = **32,850 tCO_2 – 0 = 32,850tCO_2**

This is an estimation of the likely quantity of emission reductions that may arise as a result of the project activity. The actual quantity of emission reductions achieved for the purpose of determining the quantity of CERs generated, will be calculated annually according to the monitoring plan.

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

Estimation of the Project's ERs

Year	Estimation of project activity emissions (tones of CO_2e)	Estimation of baseline emissions (tones of CO_2e)	Estimation of leakage (tones of CO_2e)	Estimation of overall emission reductions(tones of CO_2e)

[45] For this second crediting period the default values of W_{OM} = 0.25 and W_{OM} = 0.75 are used.

[46] Since the energy generating equipment is new and is not replacing any existing facility, the project doesn't produce leakage.

2011	0	24,637	0	24,637
2012	0	32,850	0	32,850
2013	0	32,850	0	32,850
2014	0	32,850	0	32,850
2015	0	32,850	0	32,850
2016	0	32,850	0	32,850
2017	0	32,850	0	32,850
2018	0	8,213	0	8,213
Total	**0**	229,950	**0**	229,950

For the Project "the year" would run from April 1 to March 31, the first year of the second crediting period being April 1, 2011-March 31, 2012, and the last year of the second crediting period being April 1, 2017-March 31, 2018.

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

According to ACM002, all data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period. 100% of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards.

B.7.1 Data and parameters monitored:

Data / Parameter:	$EF_{grid,CM,y}$
Data unit:	tCO_2/MWh
Description:	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"
Source of data to be used:	As per the "Tool to calculate the emission factor for an electricity system"
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.56893 tCO_2 per MWh
Description of measurement methods and procedures to be applied:	As per the "Tool to calculate the emission factor for an electricity system"
QA/QC procedures to be applied:	As per the "Tool to calculate the emission factor for an electricity system"
Any comment:	The parameters defined in the tool have been included in this section of the PDD.

Data / Parameter:	$EF_{grid,OM,y}$

Data unit:	tCO_2/MWh
Description:	Operating 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”
Source of data to be used:	As per the “Tool to calculate the emission factor for an electricity system”
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.75579 tCO_2/MWh
Description of measurement methods and procedures to be applied:	As per the “Tool to calculate the emission factor for an electricity system”
QA/QC procedures to be applied:	As per the “Tool to calculate the emission factor for an electricity system”
Any comment:	The parameters defined in the tool have been included in this section of the PDD.

Data / Parameter:	**$EG_{m,y}$ and $EG_{n,h}$**
Data unit:	MWh
Description:	Net electricity generated and delivered to the grid by power plant / unit m, or n in year y or hour h
Source of data to be used:	COES
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Raw data recorded every 15 minutes: COES data from April 1st,2009 to March 31st ,2010. Data recorded hourly. “Poechos I - DDA OM April 1st,2009 to March 31st ,2010..xls” spread sheet
Description of measurement methods and procedures to be applied:	Directly measured by power plants energy meters and recorded every 15 minutes by COES. This data is processed s and recorded hourly by project participant in “Poechos I OM.xls” spread sheet. The proportion of data to be monitored is 100% and the data will be archived electronically.
QA/QC procedures to be applied:	Cross check with COES official data
Any comment:	Monitoring frequency: o Dispatch data OM: Hourly o BM: For the second and third crediting period, only once ex-ante at the start of the second crediting period.

Data / Parameter:	**$EG_{PJ,h}$**
Data unit:	MWh

Description:	Electricity displaced by the project activity in hour h of year y
Source of data to be used:	Information provided by project electricity meters
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Real hourly data of Poechos I during year April 1st, 2008 to March 31st, 2009 .
Description of measurement methods and procedures to be applied:	The net electricity to the grid of Poechos I is calculated as the difference between the energy meter of the substation of Sullana and the meter of the hydropower plant of Poechos II. The project participant used to meter directly the energy of Poechos I in the meter of Sullana. However, the project participant built recently other hydro power plant called Poechos II which its energy is also metered in the energy meter of Sullana. Poechos II also has its own energy meter located in its facility. Now the net electricity of Poechos I is calculated as the electricity metered in the meter of Sullana minus the energy metered in the energy meter of Poechos II. The energy meters measure electricity continuously. The proportion of data to be monitored is 100% and the data will be archived electronically. The electric meters will be implemented according to the dispatch center (COES) requirements[47], which includes the requirement for the meter to have Class 0,2 compliant metering accuracy.
QA/QC procedures to be applied:	Sales records to the SEIN or to the final client, are used to ensure consistency. The metering system will be calibrated according to the manufacturer specifications and at least every three years.
Any comment:	

Data / parameter:	$\eta_{m,y}$
Data unit:	-
Description:	Average net energy conversion efficiency of power unit m in year y
Source of data to be used:	Data from the dispatch center (COES) Annual statistics
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Net Energy Conversion Efficiencies (NEC) for all thermal plants are available in the annual statistics of COES. For ex-ante calculation it was used the most updated information that is for year 2009.
Description of measurement methods and procedures to be applied:	Every year this data will be checked with the last available annual report of COES.
QA/QC procedures to be applied:	The data from COES is reliable since efficiency is calculated according to the COES procedure Number 17 for the determination of effective power and efficiency of thermal power plants.

[47] *Procedimiento Técnico del Comité de Operación Económica del SINAC. PR – 20 Verificación del Cumplimiento de Requisitos para ser integrante del COES SINAC*, page 20. http://www.coes.org.pe/coes/Procedimientos/procedimiento_n20.pdf

	(http://www.coes.org.pe/coes/Procedimientos/procedimiento_n17.pdf). This procedure established that the efficiency of the plants have to be calculated according to international standards. For diesel engines ISO-3046-1 or its updated versions, for gas turbines: section 8 of ISO 2314: 1989 or its updated versions, for steam turbines: DIN1943, Sections 6 a 8, February 1975, or it updated version. Etc. These calculations and measurements will be performed with a COES accredited consultants and the result are reviewed and supervised by COES experts.
Any comment	This information will be monitored annually.

Data / Parameter:	$EG_{pj,y}$
Data unit:	MWh/yr
Description:	Quantity of net electricity generation supplied by the project plant/unit to the grid in year *y*
Source of data to be used:	Information provided by COES based in project electricity meters.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	57,740 Mwh. This value is the annually expected electricity production of Poechos I established in the original PDD.
Description of measurement methods and procedures to be applied:	Directly measured by Electricity meters
QA/QC procedures to be applied:	Cross check measurement results with records for sold electricity and information from COES
Any comment:	

Data / Parameter:	$EF_{CO2,i,y}$ and $EF_{CO2,m,i,y}$
Data unit:	tCO_2/GJ
Description:	CO2 emission factor of fossil fuel type *i* used in power unit *m* in year *y*
Source of data to be used:	The following data sources may be used if the relevant conditions apply:

Data source	Conditions for using the data source
Values provided by the fuel supplier of the power plants in invoices	If data is collected from power plant operators (e.g. utilities)
Regional or national average default values	If values are reliable and documented in regional or national energy statistics / energy balances
IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC	

	Guidelines on National GHG Inventories
Value of data applied for the purpose of calculating expected emission reductions in section B.5	IPCC default values Diesel Oil = 72,600 kg /TJ Residual Fuel Oil = 75,500 kg /TJ Natural Gas = 54,300 kg /TJ Coal = 87,300 kg /TJ
Description of measurement methods and procedures to be applied:	Dispatch data OM: Annually for the year *y* in which the project activity is displacing grid electricity or, if available, hourly. Further guidance can be found in Step 3 of the Tool to calculate the emission factor for an electricity system; BM: For the second and third crediting period, only once *ex ante* at the start of the second crediting period
QA/QC procedures to be applied:	–
Any comment:	

B.7.2. Description of the monitoring plan:

EndesaCarbono S.L., the CDM consultant to the Project, will provide Sinersa with a Monitoring Plan and pre-programmed spreadsheets such that the Project sponsor will only need to collect the information as described and apply the formulas as instructed in the Monitoring Plan. COES, the dispatch center will be the only data provider for the annual ex-post calculation of the Project's ERs. The designated project staff will confirm these data with their own records, which they will cross check with sales receipts. Further details of the MP are available in Annex 4.

The monitoring methodology and plan for the project ("the MP") follows the methodology ACM002 version 12.1.0 . All data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period. 100% of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards.

Components of the operational and management structure implemented by the plant are:

- A transparent system for the collection, computation and storage of data, including adequate record keeping and data monitoring systems;
- Clear procedures and protocols for collection and entry of data, use of workbooks and spreadsheets and any assumptions made, so that compliance with requirements can be assessed by a third party. Paper-based systems are also used as back-ups in the event of electronic system failures;
- A competent Project Manager, who is in charge of, and accountable for, the generation of data, monitoring, record keeping, and computation of ERs, and of audits and verification. He officially signs all worksheets;
- Internal training to staff to enable them to undertake the tasks required by the MP.

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 Monitoring Methodology and Monitoring Plan were completed on 30/11/2004 by:
Senior Financial Specialist
Francisco Fernández-Asín
The NCDMF
Washington DC
USA.
The NCDMF is also a project participant listed in annex 1 of this document.

Updated in August 4th 2010 by:

Francisco Fernández-Asín
EndesaCarbono S.L.
E-mail: francisco.asin@endesacarbono.com
www.endesacarbono.com

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:

01/11/2002

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

40 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:

Starting date of the first crediting period: 01/04/2004.

The starting date of the second crediting period is 01/04/2011.

C.2.1.2. Length of the first crediting period:

7 years

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

N/A

C.2.2.2. Length:

N/A

SECTION D. Environmental impacts

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

An EIA was a legal requirement for The Project. Electric Concessions Law ("ECL")'s Article 25 lists the EIA as a requirement to obtain a definitive concession from the *MINEM*. The Project needed a definitive concession to be granted by the *MINEM66*, because it attained the construction and operation of an electricity generation activity of more than 10 MW of installed capacity.

Numerous environmental assessment documents were completed during preparation of The Project. An EIA was completed for the hydropower project specifically, which analyzed impacts during construction and operation. In part due to the highly intervened surroundings, no major impacts were identified. Construction impacts were well managed through proper environmental practices, as enumerated in an Environmental Management Plan submitted and approved by IDB, DEG and The World Bank – all financiers involved in the Project. A separate EIA was completed for the transmission line, with, again, no major impacts identified.

Communities along the transmission line were given the opportunity to connect to the line. The Project has lately installed a 22.9 KV keys yard to feed 3 small isolated systems: The Lancones system, The Chira system, and a third one that goes into a small population located close to the Ecuadorian border. These three small populations' consumptions will be partly "subsidized" by the Peruvian Government according to The Department of Energy and Mines overall initiative regarding social development and rural electrification: *FOSE67* and Rural Electrification Plan, respectively.

Other direct beneficial effects resulting from The Project include:

-Supply of a clean source of energy;
-Training to locals on the adequate uses of electricity;
-Tax collections in the project area will boost the availability of funds for the development of local communities at an estimated annual average of 500,000 USD;
-Creation of more than 200 jobs during the construction phase, employing exclusively locals impacting positively more than 200 families;
-Contribution to the domestic capacity building efforts in environmentally sound technologies (EST) promoting the participation of local companies in the project activity including the manufacturing, for the first time in Peru, of Kaplan turbines.
-Creation of around 30 permanent positions for the operation of the hydroelectric plant transferring know how in operation, maintenance and control of hydroelectric equipment and systems. These positions will utilize locally hired staff, who will be trained during the construction phase;
-Development of the poorest zones of the country, which using electricity will have the opportunity to start productive activities. Initially these will be promoted through the maximum use of local supplies;
-First project in the Ecuadorian - Peruvian border, which will serve as a good reference projects for future initiatives for the sustainable development of this area with low human development indexes (HDI);
-Mitigate the migration of peasants to the coastal cities of Peru;
-SINERSA has expressed its commitment to education and local technical training;

-Improvement and reduction of operating costs of the Poechos dam including the elimination of diesel based generators currently supplying electricity to the dam;
-Increase in direct investment in the Project's area of around 5 Million USD; and
-Increase in investment in Peru of nearly 16.5 Million USD

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

EIA report approval by Environmental Agency:
March 13, 2003 (project by CONAM)
March 31, 2003 (EIA by *MINEM*)
Other Permits: Water concession

Potential Environmental Impacts of The Project:

Environmental	Magnitude (High, Medium, Low)	Comments
Increased erosion	Low	No destruction of the local forest was caused, therefore this impact was minor.
Deterioration of the landscape	Low	All works are overshadowed by the existing civil works of the dam; therefore no deterioration of the landscape is expected.
Air emissions	Low High (+)	Very little impact caused only from the diesel generators to be used during construction. The Project will result in the reductions of local pollution and carbon emissions to the atmosphere, which will have a positive effect both locally and globally.
Loss of vegetation and biodiversity	Low	No impact, because the density within The Project area is low, and the river is highly intervened.
Loss of agricultural area	Low	The Project will not cause any loss of agricultural areas.
Lack of water for biological functions in the river	Low	Sponsor is working with authorities to ensure that the minimum ecological flow of 10 m3/s is maintained at all times

Source: The sponsor

SECTION E. Stakeholders' comments

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

As part of Environmental Impact Assessment guidelines and procedures by The Government of Peru and in full compliance with World Bank Safeguard Policies, several workshops with the local communities took place. Each EIA (power plant and transmission line) was consulted with affected groups, and were available for comment to NGOs through the environmental agency. The EIA for The Project was consulted in 1997 during the process of concessioning. Announcements were posted in local newspapers. The EIA for the transmission line was consulted publicly on July 23, 2003 in Sullana.

E.2. Summary of the comments received:

As part of the EIA process, local stakeholders were consulted. The summary EIA reports include a section on the public consultation process, wherein the groups consulted and their comments are detailed.

The EIAs are available for public review at the Department of Energy and Mines (MINEM), and are available locally. Local stakeholders' questions revolved around concerns from surrounding municipalities about the timing for the electrification of their villages.

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

Because no negative comments were received, The Project Developer outlined its own initiatives to continue with the community support of The Project. The following social priorities were undertaken during design, construction and will continue to be undertaken in The Project operation:

-Consolidate the good relationship with the locals and keep close communication with the community of Lancones;
-Hire and train local workers for construction and operation;
-Develop local technical capabilities;
-Maximum use of local products, supplies and materials for The Project;
-Contract Peruvian companies to perform the planned activities, including the manufacturing of the first Kaplan turbines to be made in Peru;
-Prioritize the target of the social investment with the community;
-Promote the improvement of the educational level;
-Address World Bank Safeguard Policies

In addition, and as a response to local stakeholders' comments, The Project has cooperated with an ambitious *MINEM*-initiative Rural Electrification Plan by creating three new "small electric systems" or sub-grids from the SINERSA's transmission lines. The impact of electricity supply in this underdeveloped area close to the border with Ecuador (and once considered a security zone) is instrumental for the area's development. The Governmental plan was possible by The Project's cooperation, and the project's consideration of local stakeholders' concerns regarding local electrification.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Sindicato Energético S.A. (SINERSA)
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URL:	
Represented by:	
Title:	General Manager
Salutation:	Mr.
Last Name:	Zdravkovic
Middle Name:	
First Name:	Branislav
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Mobile:	
Direct FAX:	
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Organization:	International Bank for Reconstruction and Development (IBRD) as the Trustee of the The Netherlands Clean Development Mechanism Facility ("the NCDMF").
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Represented by:	Joëlle Chassard
Title:	Manager, Carbon Finance Unit
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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

The Project has not received any type of public funding or public financial help.

Annex 3

BASELINE INFORMATION

Table A3-1 below shows EF_{EL}s calculations with actual 2009 NECs from the *Annual Statistics* published by COES. In the monitoring, EF_{EL}s should be updated using the latest *Annual Statistics.*

Table A3-1: EF_{EL} calculations 2009

Code	Thermal Plant	Technology	CO_2 emission factor tCO_2/MWh
ag_tg1	AGUAYTIA 1 (2)	Natural Gas	0.60
ag_tg2	AGUAYTIA 2 (2)	Natural Gas	0.60
bvista1	BELL MAN 1,2	Diesel 2	0.90
bvista2	BELL MAN 1,2	Diesel 2	0.90
calana123	CALANA 123	Residual 6	0.67
calana4	CALANA 4	Residual 6	0.67
ccomb	C. COMBINADO	Diesel 2 CC	0.89
chi_slz12	SULZER CHILINA	Diesel 2	0.90
chicl_o	DS CHICLAYO OESTE-D	Diesel 2	0.90
chiltv1	chiltv1	R500	0.84
chiltv2	TV2 CHILINA	R500	0.84
chiltv3	TV3 CHILINA	R500	0.84
chimb	TG1 CHIMBOTE	Diesel 2	0.90
cnp_mann	DS PACAS-MAN	Residual 6 and Diesel 2	0.71
cnp_slz	DS PACAS-SULZER	Residual 6	0.67
dolores1	DOL ALCO 1-2 GM 1-2-3	Diesel 2	0.90
dolores2	DOL ALCO 1-2 GM 1-2-3	Diesel 2	0.90
ilo1catk	KATCATO (ENERSUR)	Diesel 2	0.90
ilo1tg1	TG1 ILO	Diesel 2	0.90
ilo1tg2	TG2 ILO	Diesel 2	0.90
ilo1tv1	ILO TV1	R500	0.84
ilo1tv2	ILO TV2	R500	0.84
ilo1tv3	ILO TV3	R500	0.84
ilo1tv4	ILO TV4	R500	0.84
ilo2_carb	TV CARBON ILO II	Coal	0.78
mal_tg1	TG1	Natural Gas	0.60
mal_tg2	TG2	Natural Gas	0.60
mal_tg3	TG3	Natural Gas	0.60
mal_tg4	TGN4	Natural Gas	0.60
moll123	MOLLENDO 1,2,3	R500	0.84
molltg1	TGM1 MOLLENDO	Diesel 2	0.90
molltg2	TGM2 MOLLENDO	Diesel 2	0.90
moq12	MOQUEGUA	Diesel 2	0.90
paita1	DS PAITA1	Diesel 2	0.90
paita2	DS PAITA2	Diesel 2	0.90
piura1	DS PIURA1	Diesel 2	0.90
piura2	DS PIURA2	Diesel 2	0.90
shcummins	CUMMINS	Diesel 2	0.90
shou_tv1	TV1 SHOUGESA	R500	0.84
shou_tv2	TV2 SHOUGESA	R500	0.84
shou_tv3	TV3 SHOUGESA	R500	0.84
sullana	DS SULLANA	Diesel 2	0.90
taparachi	TAPARACHI	Diesel 2	0.90
tg_piu	TG PIURA	Diesel 2	0.90
tintaya	TINTAYA	Diesel 2	0.90
tp55	Chilca1	Natural Gas	0.60
tp56	Kallpa TG1	Natural Gas	0.60
tp57	Oquendo	Natural Gas	0.60
tp58	Chilca3	Natural Gas	0.60
tp59	CT Santa Rosa TG8	Natural Gas	0.60
tp60	CT Emerg Trujillo	Diesel 2	0.90
tp61	Ventanilla Vapor	Natural Gas CC	0.39
tp62	CT Paramonga	Biomasa	0.00
tp63	TP63	Unknown	0.00
tp64	TP64	Unknown	0.00
tp65	TP65	Unknown	0.00
tp66	TP66	Unknown	0.00
truji	TG TRUJILLO	Diesel 2	0.90
trupal	TRUPAL	Residual 6	0.67
tumbes	TUMBES	Residual 6	0.67
uti_5	TG S.ROSA UTI5	Diesel 2	0.90
uti_6	TG S.ROSA UTI6	Diesel 2	0.90
vent3	TG VENTANILLA-3	Diesel 2	0.90
vent4	TG VENTANILLA-4	Diesel 2	0.90
westin	TG WESTINGHOUSE	Diesel 2	0.90
yarinac	Yarinacocha (5)	Residual 6	0.67

Calculation EF_{EL}s:

COEF(tCO2/MWh)	Open Cycle					Combined Cycle	
Type of Fuel	D2	R6	R500	Natural gasGas	Coal	D2	Natural Gas
NEC	29.02%	40.32%	32.47%	32.84%	40.20%	29.30%	50.50%
EF_{CO2} (tCO2/Gigajoule)	0.0726	0.0755	0.0755	0.0543	0.0873	0.0726	0.0543
COEF(tCO2/MWh)	**0.90**	**0.67**	**0.84**	**0.60**	**0.78**	**0.89**	**0.39**

Source for NECs: Average NECs per technology. NEC per plant is available in COES annual statistics 2009 page 35 Chart No.4.7.

Source of EF_{CO2}: IPCC 2006 default values at the lower limit of uncertainty at a 95% confidence interval as provided in table 1.4 of chapter 1 of vol 2(Energy) of the 2006 IPCC Guidelines on National GHG inventories.

Table A3-1 above has the emission factor formulas inserted in it. Actual NECs (Average net energy conversion efficiency of power unit m in year y = $\eta_{m,y}$), as well as data on technology and fuel were obtained from COES. All this data was publicly available at the COES website in its annual statistics. The specific information source is the chart entitled "Costos Variables de las Centrales Termoeléctricas del SINAC", which appeared in the COES Annual Statistics (*Estadística anual de Operaciones*) for the year 2009 as chart number 4.7.

Justification of the usage of COES information system data for baseline calculation:

In the baseline calculation, data that is not registered by COES has been disregarded and only COES data is considered to be the best approximation of total SEIN data, for both generation and installed capacity additions. Moreover, COES data is deemed to allow for good monitoring practices because:

1. There is no better quality data of the SEIN production than what is collected by COES. The information of plants connected to the SEIN but not registered in COES regarding generation and installed capacity additions is provided by the plants' management periodically to the MINEM. However, this data does not pass through a verification or validation process, nor is it required to comply with technical standards as rigorously as COES requires from their power plant members;
2. The limitation of MINEM's final annual reports and data availability would not allow good monitoring practice, for example they don't have hourly dispatch data.;
3. The generation of these other plants connected to the SEIN but not registered by COES, is irrelevant as it comprised only 2% of total SEIN electricity generation in 2008, as Table A-3 below shows.

Table A3-2: Generation in SEIN and COES

	SEIN (GWh)	COES (GWh)	COES/SEIN	Not recorded by COES
2008	30,104	29 559	0.98	0.02
2007	27,806	27,255	0.98	0.02
2006	25,251	24,762	0.98	0.02
2005	23,434	23,001	0.98	0.02
2004	22,288	21,903	0.98	0.02
2003	20,999	20,689	0.99	0.01
2002	20,018	19,658	0.98	0.02
2001	18,755	18,463	0.98	0.02

Source: *Anuario Estadístico MINEM*, 2001 - 2008 *and Estadística de Operaciones*, COES, 2001 – 2008.

Annex 4

MONITORING INFORMATION

TABLE OF CONTENTS

I. Background Information

The baseline methodology and monitoring methodology for the Project are in accordance with the approved consolidated baseline methodology (ACM0002. Version 12.1.0): "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" (The Baseline Methodology).

The Project is a hydroelectric power plant located in Peru, in the Northwestern Department of Piura. The Project generates electricity without emitting GHG. It reduces anthropogenic GHG emissions by displacing GHG that are emitted when burning fossil fuels to generate power. Methane and Carbon Dioxide emissions are negligible. Therefore there is not need to monitor leakage and it will not be taken into account when calculating ERs.

The spatial extent of The Project boundary is the *SEIN*. The Project is connected to the *SEIN* through the Sullana Substation, which belongs to Electronoroeste S.A. (ENOSA). The 57.740 GWh (approx.) of electricity generated per year will be sold to ENOSA, a stated-owned enterprise. Until now, neither electricity exports from the *SEIN* nor electricity imports to the *SEIN* have taken place.

II. Purpose of the Monitoring Plan

The CDM defines monitoring as the systematic surveillance of a project's performance by measuring and recording performance-related indicators relevant to the project activity. This report presents the Monitoring Plan (MP) for the Project. The MP defines a standard against which the performance in terms of the Project's ERs will be monitored and verified, in conformance with all relevant requirements of the CDM of the Kyoto Protocol. Both the Baseline and the MP are subject to verification procedures.

III. Use of the Monitoring Plan by the Operator

The MP identifies key performance indicators of the Project and sets out the procedures for metering, monitoring, calculating and verifying the ERs generated by the Project annually. Adherence to the instructions in the MP is necessary for the Operator to successfully measure and track the impact of the Project, and to prepare all data required for the periodic audit and verification process that must be undertaken to confirm the attainment of the corresponding ERs.

The MP assists the Operator in establishing a credible, transparent, and adequate data measurement, collection, recording and management system to successfully develop and maintain the proper information; required for an audit and for the verification and certification of the achieved ERs and other Project outcomes. Specifically, the MP provides the requirements and instructions for: (i) establishing and maintaining the appropriate monitoring system, including spreadsheets for the calculation of ERs, (ii) implementing the necessary measurement and management operations, and (iii) preparing for the requirements of independent third party verifications and audits.

The MP ensures environmental integrity and accuracy of crediting ERs by allowing actual ERs to be accounted for only after they have been generated. The MP must therefore be used throughout the period in which the Project has committed to, or desires to sell and track ERs. It must be adopted as a key input into the detailed planning of the Project, and included as one of its operational manuals.

The MP can be updated and adjusted to meet operational requirements. The Verifier approves such modifications during the process of initial or periodic verification. In particular, any shifts in the baseline scenario may lead to such amendments, which may be mandated by the Verifier. Amendments may also be necessary as a consequence of new circumstances that affect the ability to monitor ERs, as described here, or to accommodate new or modified CDM rules.

IV. Organizational, Operational and Monitoring Obligations

A. Obligations of the Operator

Monitoring performance of the Project requires the fulfillment of operational data collection and processing obligations from the Operator. The Operator has the primary obligation of ensuring that sufficient and accurate information is available to calculate ERs in a transparent manner and of allowing for a successful verification of accounted ERs.

Key responsibilities: The Manager of the Project has primary authority and responsibility for project management. Together with the Sales Manager, they will form the steering committee that will approve the monitoring reports. The sales office of the Project will be in charge of the calculation of ERs and will report to the steering committee. This organizational structure for this activity is included in the monitoring plan in the "ERCP Organizational Structure".

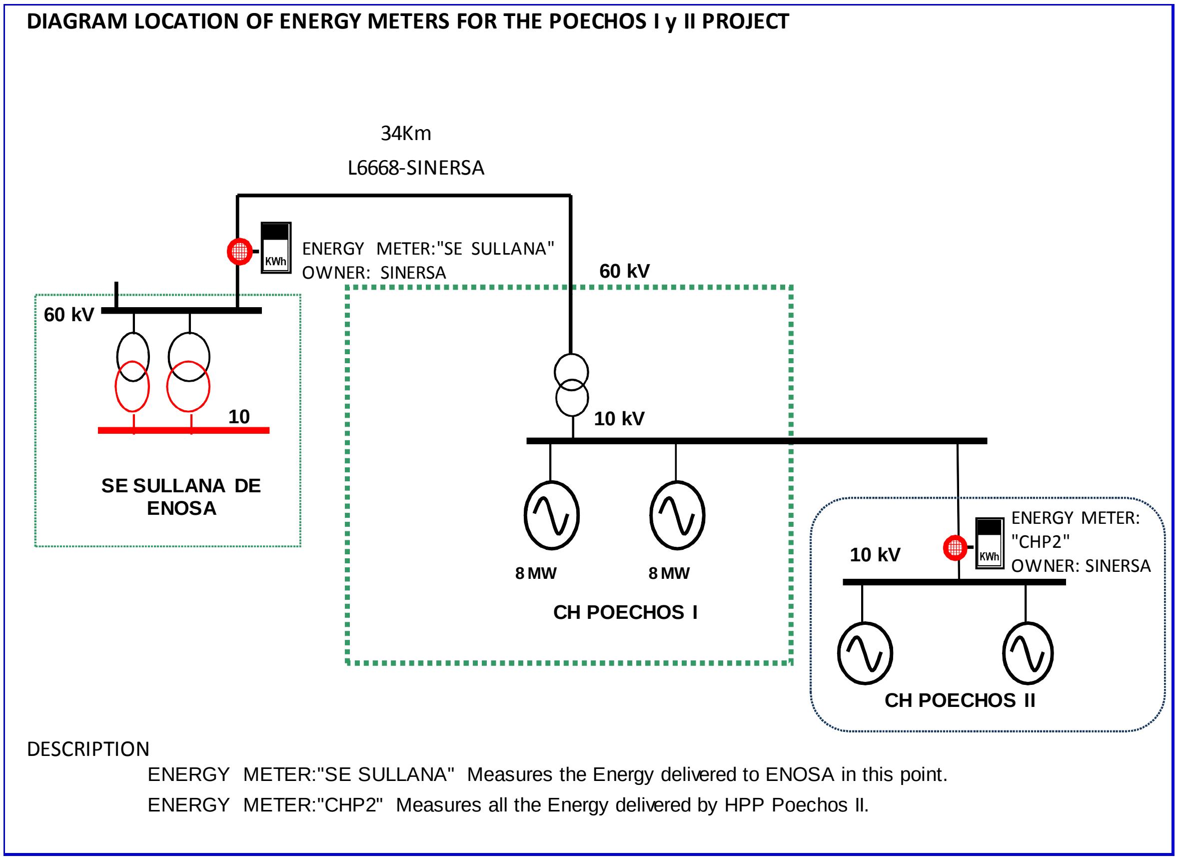
Training of monitoring personnel: The team established in the Emissions Reductions Calculation Procedure (ERCP) Organizational structure, and composed of the monitoring plan steering committee and the ERCP management, will be trained by Endesacarbono in a one day workshop on a comprehensive set of tools and knowledge required to implement the monitoring plan. The monitoring plan and associated training will build the capability of the monitoring plan steering committee and ERCP management to replicate - on an ex-post basis – an equivalent process that has been demonstrated in this PDD for an ex-ante emissions avoidance calculation for the period April 1st 2009 – March 31st , 2010. Training will include: a) accurate monitoring of the performance and output characteristics of the plant to record and keep accurate data; b) collection and integration of utility data for the current year; c) incorporation of these data sets into spread sheets pre-prepared by Endesacarbono, and d) consistently calculating verifiable CERs as a function of measured plant output against a current-year emission factor that serves as a recognized proxy for emissions displaced from the grid.

Equipment Required: Adequate computer services and file storage are required, and maintenance of computers and data contained therein are described under the following section. Adequate metering and logging equipment will be procured for measuring electricity generation by the plant, and net levels of electricity dispatched for sale to the grid. The electric Meters will be implemented according to the dispatch center (COES) requisites[48] which includes that the meter should be a Class 0,2 compliant metering accuracy.
As explained in section B.7.2 of the PDD, no other special monitoring equipment is needed for this project, which relies primarily on COES data for calculating the relevant grid emission factor.

Procedures for maintenance and installation of equipment, as well as calibration, will be performed according to manufacturer specifications of equipment. The periodic calibration would be performed at least every 3 years. All measurements, data gathering, record keeping, and procedures for dealing with possible monitoring data adjustments will be performed in specific consideration of the data gathering requirements of the Monitoring Plan and as determined as adequate for meeting the baseline and monitoring requirements described in ACM0002 ("Consolidated monitoring methodology for grid-connected electricity generation from renewable sources" Version 12.1.0).

Meter Location:

[48] Procedimiento Técnico del Comité de Operación Económica del SINAC. PR – 20 Verificacion del Cumplimiento de Requisitos para ser integrante del COES SINAC. Page 20.
http://www.coes.org.pe/coes/Procedimientos/procedimiento_n20.pdf



The net electricity to the grid of Poechos I is metered in the energy meter of Sullana . However, the project participant built recently other hydro power plant called Poechos II which its energy is also metered in the energy meter of Sullana. Poechos II also has its own energy meter located in its facility. Therefore the net electricity to the grid of Poechos I is the electricity metered in the meter of Sullana minus the energy metered in the energy meter of Poechos II.

Data Collection and Integration: It is required that the Operator calculate the Project's ERs based on most recent available information, following the ERCP presented in this report. The Operator must gather and process information needed to monitor ERs. All data required for calculating the Emission Margin will come from the COES information system. Electricity production by the plant and any internal usage will be metered continuously to account for the net level of electricity sold to the grid, and these records and sales receipts will be cross-referenced with COES data, which itself will contain a record of the plant output, along with all other plants in the SEIN.

Data gathering and processing should be done monthly by the Operator, as follows:

Monthly Data collection

	• At the end of each month:

COES (Data Provider)	• Report hourly generation of plants in the SEIN (measurement: 15' or 30' [49]) • Report dispatch merit orders. As the project is an active member of COES all data comes from COES. The merit orders will be calculated monthly as the average of the weekly merit orders published by COES. • Use real NECs per power plant in the SEIN
Operator (Data processor)	• Report of the electricity measured in the meters of the project. • Substantiate all ER claims with sale receipts . • Fill in monthly data in all required spreadsheets, following the ERCP • Issue a monthly report

The Operator should calculate ERs on the basis of this MP, following the ERCP, for the purpose of claiming ER credits. The CERs would be granted *ex-post* verification. It is believed that the MP approach presented here will result in an accurate, yet conservative calculation of ERs. However some uncertainties may lead to a deviation of monitored ERs and the verified ERs, especially errors in the data monitoring and processed system. The Operator is expected to prevent such errors and the verification audits are expected to uncover any possible errors.

All data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period. 100% of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards. In addition, the monitoring provisions in the tools referred to in this methodology apply.

Procedures identified for project performance reviews and corrective actions: SINERSA will adopt all appropriate procedures to measure the performance of the project. This includes appropriate meters to measure the dispatched electricity as well as the procedures to guarantee the reliability of the data.

Based on the ERCP Quality Control Procedure, quality control and inspection procedure will be established for monitoring of the proposed project activity to assure monitoring accuracy. Such procedures will include, but not be limited to, the following:

- During yearly consolidation of monthly calculation, spreadsheets will be reviewed.
- Corrective actions will be applied in case of malfunction/breakdown or for more accurate monitoring and reporting.
- Once a year an internal audit will be performed by the ERCP steering committee to see if the monitoring plan has been performed according the guidelines established in the PDD.
- Project performance review every year according to the PDD.

Independent verification of monitoring results and achievement of the emission reduction expected in the PDD is a critical outcome for all CDM projects. The ERCP management should work closely with the verifier (DOE) to assure a dependable and transparent outcome, and they will:

- Keep efficient contact with the DOE who verifies the project's emission reduction.

[49] Half an hour measurement is still acceptable if the total *SEIN* production calculated with it does not deviate greatly (i.e. more than 1%) from total *SEIN* Production calculated with the 15-minute measured data.

- Provide all necessary monitoring information about emission reduction to facilitate the verification work.
- During the crediting period, always take into account requests by the CDM Executive Board and conduct preparatory work for the verification to obtain result of high quality and efficiency.
- The ERCP management should be prepared in advance the monitoring report and before verification, it should be reviewed by the ERCP steering committee.
- The project's management and its operators also should cooperate for relevant communication to answer all questions raised by DOE for emission reduction verification.

Immediately upon detecting a problem or being informed of a discrepancy, ERCP management will take immediate action to rectify it. Should COES fail to provide adequate information, the steering committee will file a claim with COES to obtain the information (and as a member of COES, the project sponsor has the right to receive information from COES). If a major investment is required, the ERCP management will notify the steering committee to ask the management of SINERSA to invest in the monitoring personal or/and equipment.

B. Emissions Reductions Calculation Procedure and Required Spreadsheets
The ERCP is the basic instrument for gathering, recording and processing information that will result in the measured ERs. The operator shall keep the project ERCP as a manual. The ERCP should contain: i) data gathered from COES and ii) data processed by the operator. All data processing should be done in Excel, for which a new version will be acquired annually to avoid 'versioning' problems over time. The ERCP is designed for monthly calculation, based on final monthly COES reports. Although it will only be possible to know the ERs at the end of each year (March 31 for the project), filling data monthly in the required spreadsheets will provide time to review formulas, minimize errors and have data readily available for the verifier in any period of the year. There is a procedure to calculate the monthly merit orders and a spreadsheet to calculate the operating Margin: Poechos I DDA-OM.xls.

Procedure of calculation of monthly order of merits

1. Documents received from COES with corresponding data are in the sheet:
    a. […]\Period 2009-2010\Procedure for obtains Order of merits\Data Originals COES.

In this directory each file is extracted the data relevant and necessary to paste only values in the spreadsheet shown in the next step.

2. With the data (only pasted values) it will be created the sheets "20XX-MM MMM 20XX OM.xls". P. example: "2009-04 ABR 2009 OM.xls".

3. This file is a table that in column N (Last of each table) shows the equivalent costs Barra Santa Rosa, each power plant for each period of days.

4. The first thing is to get the cost equivalent Barra Santa Rosa, monthly weighted average, for that, on the column O of the row on which it is indicated the period of each table , it is calculated the number of days that covers each period.

5. In the cell O2 it is estimated the number of days of the month in calculation.

6. In the cells in column R it is being calculated the weighted average of each plant.

7. Finally, in the columns T and Y it is copied the table and Plant Cost Eq. Santa Rosa, ordering from the low to the high cost which would be for his Order of Merit.

DDA-OM Spreadsheet:
This Excel file contains all data and formulas necessary to calculate the Dispatch Data Analysis Operating Margin. The data's year is the year of project generation (1 April - 31 March). 14 worksheets compose the DDA-OM Spreadsheet:

- Worksheet #0: EF_{EL}s (tCO_2/MWh) calculation for each plant in the SEIN. The COEF will be calculated *ex- post* annually along the first crediting period.
- Worksheet #1: EF_{EL}s (tCO_2/MWh) to assign to each plant in the SEIN.
- .
- Worksheet #2 to Worksheet #13: One worksheet per month of the year. These worksheets contain the hourly generation of the plants in the SEIN.

<u>Worksheet #0</u>

Table # 1: EF_{EL}s Calculation

Table A4-1 below shows EF_{EL}s Calculations per technology and is already filled with actual 2009 NECs from COES Annual Statistics 2009[50] . These are provided as examples only in order to derive a reference baseline estimation. In actual monitoring, EF_{EL}s would vary according to the information published by COES each year.

Table A4-1: EF_{EL}s Calculation

[50] COES. Estadística de Operaciones. In year 2008, NEC appears as "Eficiencia Térmica %" in the chart No 4.7

TECHNOLOGY	Generation Unit	NECs	Generation GWh	Total			Average NEC per technology
CC TG-VAPOR	VENTANILLA CCOMB TG 3 & TG 4 - GAS	50.50%	1138.250		574.816		0.5050
	VENTANILLA CCOMB TG 3 - GAS	50.20%	0.000		0.000		
	VENTANILLA CCOMB TG 3 & TG 4 - GAS F.DIRECTO	48.50%	0.000		0.000		
	VENTANILLA CCOMB TG 4 - GAS	48.40%	0.000		0.000		
	VENTANILLA CCOMB TG 3 - GAS F.DIRECTO	47.80%	0.000		0.000		
	VENTANILLA CCOMB TG 4 - GAS F.DIRECTO	47.60%	0.000	1138.250	0.000	574.816	
	CICLO COMBINADO - D2	29.30%	0.000		0.000	574.816	0.2930
TG GAS NATURAL	CHILCA1 TG3 -GAS	33.20%	412.180		136.844		0.3284
	CHILCA1 TG1 -GAS	34.80%	996.140		346.657		
	CHILCA1 TG2 -GAS	34.50%	1144.140		394.728		
	KALLPA TG2 -GAS	33.60%	503.690		169.240		
	KALLPA TG1 -GAS	33.30%	734.240		244.502		
	VENTANILLA TG 3 -GAS	34.50%	978.810		337.689		
	VENTANILLA TG 4 -GAS	33.70%	1138.250		383.59025		
	STAROSA TG8 GAS	34.50%	42.960		14.8212		
	AGUAYTIA TG 1 -GAS	30.70%	601.860		184.77102		
	AGUAYTIA TG 2 -GAS	30.10%	436.270		131.31727		
	OQUENDO TG1 -GAS	33.60%	187.440		62.980		
	STA ROSA WEST TG7 -GAS	30.50%	217.590		66.365		
	STA ROSA WEST TG7 -GAS CON H2O	29.40%	0.000		0.000		
	STA ROSA UTI 6 -GAS	27.00%	149.770		40.438		
	STA ROSA UTI 5 -GAS	26.80%	0.000		0.000		
	MALACAS2 TG 4 -GAS	27.50%	481.330		132.36575		
	MALACAS2 TG 4 -GAS CON H2O	25.70%	0.000		0		
	MALACAS TG 2 -GAS	21.60%	54.390		11.74824		
	MALACAS TG 1 -GAS	21.20%	44.090	8123.150	9.34708	2667.403	
TV CARBÓN	ILO2 TV1 - CARB	40.20%	929.150	929.150	373.5183	373.518	0.4020
TV RESIDUAL	SAN NICOLAS TV 3 -R500	30.70%	77.640		23.83548		0.3247
	SAN NICOLAS TV 1 -R500	28.80%	27.910		8.03808		
	SAN NICOLAS TV 2 -R500	28.50%	26.130		7.44705		
	ILO1 TV3 -R500	33.60%	241.450		81.1272		
	ILO1 TV4 -R500	34.50%	147.850		51.00825		
	CHILINA TV3 -R500	22.90%	26.060		5.96774		
	ILO1 TV2 -R500	34.90%	9.180		3.20382		
	CHILINA TV2 -R500	21.00%	0.000	556.220	0	180.628	
DIESEL B2/R5/R6	MOLLENDO 123 -R500	43.20%	42.750		18.468		0.4032
	CHILINA SULZ 12 -R500 D2	42.30%	0.000		0		
	TUMBES -R6	42.00%	24.490		10.2858		
	CHICLAYO OESTE -R6	34.00%	0.000		0		
	PIURA 2 -R6	32.50%	0.000		0		
	ILO1 CATKATO -D2	41.70%	6.040		2.51868		
	PIURA 1 -R6	32.10%	0.000		0		
	SAN NICOLAS CUMMINS -D2	37.90%	1.200		0.4548		
	YARINACOCHA -R6	39.20%	11.190		4.38648		
	BELLAVISTA MAN 1 -D2	38.00%	0.280		0.1064		
	PIURA 2 -D2	37.30%	31.620		11.79426		
	TRUJILLO NORTE -D2	37.90%	0.850		0.32215		
	PIURA 1 -D2	37.00%	0.000		0		
	PAITA 1-D2	34.40%	2.010		0.69144		
	SULLANA -D2	34.00%	5.980		2.0332		
	TAPARACHI -D2	35.90%	2.040		0.73236		
	CHICLAYO OESTE -D2	35.00%	0.000		0		
	PAITA 2 -D2	32.20%	0.000		0		
	BELLAVISTA ALCO -D2	31.40%	0.000	128.450	0	51.794	
TG D2	ILO1 TG2 -D2	32.70%	29.630		9.68901		0.2902
	STA ROSA WEST TG7 -D2	33.10%	7.570		2.50567		
	STA ROSA WEST TG7 -D2 CON H2O	32.80%	0.000		0		
	VENTANILLA TG 4 -D2	36.50%	0.000		0		
	VENTANILLA TG 3 -D2	36.30%	0.910		0.33033		
	VENTANILLA TG 4 -D2 CON H2O	35.70%	0.000		0		
	VENTANILLA TG 3 -D2 CON H2O	35.60%	0.000		0		
	ILO1 TG1 -D2	30.30%	12.170		3.68751		
	STA ROSA UTI 6 -D2	30.30%	8.370		2.53611		
	STA ROSA UTI 5 -D2	29.50%	0.000		0		
	PIURA TG -R6	20.60%	0.000		0		
	TRUJILLO SUR TG -D2	24.40%	0.850		0.2074		
	CHIMBOTE TG3 -D2	23.50%	10.890		2.55915		
	CHIMBOTE TG1 -D2	22.70%	0.000		0		
	PIURA TG -D2	21.30%	14.060	84.450	2.99478	24.510	

Table A4-1 contains pre-established formulas to calculate the emission factors. Data on actual NECs, technology and fuel has to be updated each year. New thermal plants have to be included in

the year they appear. All these variables should be updated yearly according to the information in the Annual Statistics publicly available on the COES website, therefore, the emission factors of each year depends on the latest Annual Statistics published on the COES website. The specific information source for all these data is the chart entitled “Costos Variables de las Centrales Termoeléctricas del SINAC”, which in the year 2009 of the COES Annual Statistics, appeared in chart number 4.7., “Estadística Anual de Operaciones”.

Worksheet #1

The following Table A4-3 assigns a EF_{EL} to each plant in the SEIN according to its COEF established in Worksheet #0, Table A4-1.

Table A4-3 holds up to 100 plants, of which 34 are hydropower plants and 66 are thermal plants. 63 of the 100 plants already exist, 30 of which are hydropower plants and 33 are thermal, while 37 are future plants, of which 4 will be hydropower plants and 33 thermal plants. Data on future plants should be filled as the arrows in Table A4-3 indicate, as they enter the SEIN. Plants that did not dispatch in any hour of the year in question should not be considered for the DDA-OM calculation at all, so that they do not occupy extra-space unnecessarily.

Table A4-3: Plants in the SEIN by Technology and Assigned EF_{EL}

ag_tg1	AGUAYTIA 1 (2)	Natural Gas	0.60
ag_tg2	AGUAYTIA 2 (2)	Natural Gas	0.60
arcata	Arcata	Hydro	0.00
aricota	CH ARICOTA	Hydro	0.00
bvista1	BELL MAN 1,2	Diesel 2	0.90
bvista2	BELL MAN 1,2	Diesel 2	0.90
cahua	Cahua	Hydro	0.00
calana123	CALANA 123	Residual 6	0.67
calana4	CALANA 4	Residual 6	0.67
call	CH Callahuanca	Hydro	0.00
ccomb	C. COMBINADO	Diesel 2 CC	0.89
chariii	CH CHARCANI	Hydro	0.00
chariv	CH CHARCANI	Hydro	0.00
charv	CH CHARCANI	Hydro	0.00
charvi	CH CHARCANI	Hydro	0.00
chi_slz12	SULZER CHILINA	Diesel 2	0.90
chicl_o	DS CHICLAYO OESTE-D	Diesel 2	0.90
chiltv1	chiltv1	R500	0.84
chiltv2	TV2 CHILINA	R500	0.84
chiltv3	TV3 CHILINA	R500	0.84
chimay	CH Chimay	Hydro	0.00
chimb	TG1 CHIMBOTE	Diesel 2	0.90
cnp_mann	DS PACAS-MAN	Residual 6 and Diesel 2	0.71
cnp_slz	DS PACAS-SULZER	Residual 6	0.67
cpato	CH Cañón del Pato	Hydro	0.00
cqro	CH Carhuaquero	Hydro	0.00
dolores1	DOL ALCO 1-2 GM 1-2-3	Diesel 2	0.90
dolores2	DOL ALCO 1-2 GM 1-2-3	Diesel 2	0.90
gciego	CH Gallito Ciego	Hydro	0.00
herc	CH HERCA	Hydro	0.00
hp1	HP1	Hydro	0.00
hp2	CH El Platanal	Hydro	0.00
hp3	CH La Joya	Hydro	0.00
hp4	CH Sta Cruz	Hydro	0.00
hp5	CH caña brava	Hydro	0.00
hp6	sta Rosa1	Hydro	0.00
hp7	yuncan	Hydro	0.00
hpni	CH Huampaní	Hydro	0.00
huanchor	CH Huanchor	Hydro	0.00
huin	CH Huinco	Hydro	0.00
ilo1catk	KATCATO (ENERSUR)	Diesel 2	0.90
ilo1tg1	TG1 ILO	Diesel 2	0.90
ilo1tg2	TG2 ILO	Diesel 2	0.90
ilo1tv1	ILO TV1	R500	0.84
ilo1tv2	ILO TV2	R500	0.84
ilo1tv3	ILO TV3	R500	0.84
ilo1tv4	ILO TV4	R500	0.84
ilo2_carb	TV CARBON ILO II	Coal	0.78
machup	CH MACHUPICCHU	Hydro	0.00
mal_tg1	TG1	Natural Gas	0.60
mal_tg2	TG2	Natural Gas	0.60
mal_tg3	TG3	Natural Gas	0.60
mal_tg4	TGN4	Natural Gas	0.60
malp	CH Malpaso	Hydro	0.00
man	CH MANTARO	Hydro	0.00
mat	CH Matucana	Hydro	0.00
moll123	MOLLENDO 1,2,3	R500	0.84
molltg1	TGM1 MOLLENDO	Diesel 2	0.90
molltg2	TGM2 MOLLENDO	Diesel 2	0.90
moq12	MOQUEGUA	Diesel 2	0.90
moy	CH Moyopampa	Hydro	0.00
oro_p	CH Oroya-Pachac.	Hydro	0.00
paita1	DS PAITA1	Diesel 2	0.90
paita2	DS PAITA2	Diesel 2	0.90
pariac	Pariac	Hydro	0.00
piura1	DS PIURA1	Diesel 2	0.90
piura2	DS PIURA2	Diesel 2	0.90
ron	CH RESTITUCION	Hydro	0.00
sgab2	CH SAN GABAN	Hydro	0.00
shcummins	CUMMINS	Diesel 2	0.90
shou_tv1	TV1 SHOUGESA	R500	0.84
shou_tv2	TV2 SHOUGESA	R500	0.84
shou_tv3	TV3 SHOUGESA	R500	0.84
sullana	DS SULLANA	Diesel 2	0.90
taparachi	TAPARACHI	Diesel 2	0.90
tg_piu	TG PIURA	Diesel 2	0.90
tintaya	TINTAYA	Diesel 2	0.90
tp55	Chilca1	Natural Gas	0.60
tp56	Kallpa TG1	Natural Gas	0.60
tp57	Oquendo	Natural Gas	0.60
tp58	Chilca3	Natural Gas	0.60
tp59	CT Santa Rosa TG8	Natural Gas	0.60
tp60	CT Emerg Trujillo	Diesel 2	0.90
tp61	Ventanilla Vapor	Natural Gas CC	0.39
tp62	CT Paramonga	Biomasa	0.00
tp63	TP63	Unknown	0.00
tp64	TP64	Unknown	0.00
tp65	TP65	Unknown	0.00
tp66	TP66	Unknown	0.00
truji	TG TRUJILLO	Diesel 2	0.90
trupal	TRUPAL	Residual 6	0.67
tumbes	TUMBES	Residual 6	0.67
uti_5	TG S.ROSA UTI5	Diesel 2	0.90
uti_6	TG S.ROSA UTI6	Diesel 2	0.90
vent3	TG VENTANILLA-3	Diesel 2	0.90
vent4	TG VENTANILLA-4	Diesel 2	0.90
westin	TG WESTINGHOUSE	Diesel 2	0.90
yanan	CH Yanango	Hydro	0.00
yarinac	Yarinacocha (5)	Residual 6	0.67
yaupi	CH Yaupi	Hydro	0.00

Worksheet #2 to Worksheet #13: Hourly Generation of the Plants in the SEIN

12 monthly worksheets that contain the hourly generation of all plants in the SEIN in each month of the most recent year (April-March) should be identical in # of columns, formulas, "general organization" but not in data. Worksheets #2' – Worksheet #13' columns C to CY should be organized as follows:

COEFs:	0.00	0.00	0.00	0.00	0.00	0.56	0.67	…………….	Unknown	Unknown
TECHNOLOGY:	Hydro	Hydro	Hydro	Hydro	Hydro	Gas Turbine Natural Gas	Gas Turbine Natural Gas	…………….	Unknown	Unknown
Hours of the month	HP1…………	………..HP6	CH Yuncan	…………….	Cañon del Pato	TG1 CHILCA	AGUAYTIA 2 (2)	…………….	TP56………	……….TP70
1										
.	Future HPs		Existing HPs							
.	There is an unchangeable pre-defined order for exisiting and future HPs - for all the crediting period					Existing TPs should be placed according to grid dispatch merit order as well as future TPs				
744										

Hourly generation of hydropower plants (both existing and future) should occupy columns D to AK only. Hourly generation of thermal plants (both existing and future) should occupy columns AL to CY only. The predefined order for hydropower plants is shown below (where the "-1 position" =D column and "30th position" =AK column). This order should hold for the first crediting period. Thermal plants should be sorted according to their calculated monthly merit order in the grid dispatch. Future hydropower plants (maximum 4) are reserved a columns to the very left of columns D to AK. Future thermal plants (maximum 33) should be reserved a column to the very right of columns AL to CY, as if they were the last in the monthly merit order of the grid system dispatch. Finally, the associated EF_{EL}s of SEIN plants should be entered in the first row of the corresponding plant's column. For future plants EF_{EL} = 0.

Predefined order from left to right (D to AK) for all hydropower plants[51]

[51] The only difference between negative and positive positions is that negatives are for non-existent plants up to December 2009. Even when they are complete they should maintain that position. Note that future hydropower plants are reserved a column to the very left of Worksheet #3-Worksheet #14

-1	HP1	Hydro
1	CH La Joya	Hydro
2	CH El Platanal	Hydro
3	CH caña brava	Hydro
4	CH Sta Cruz	Hydro
5	yuncan	Hydro
6	CH MANTARO	Hydro
7	CH RESTITUCION	Hydro
8	CH Huinco	Hydro
9	CH Matucana	Hydro
10	CH Yaupi	Hydro
11	CH Oroya-Pachac.	Hydro
12	CH Malpaso	Hydro
13	Cahua	Hydro
14	Pariac	Hydro
15	Arcata	Hydro
16	CH Gallito Ciego	Hydro
17	CH Callahuanca	Hydro
18	CH Moyopampa	Hydro
19	CH Huampaní	Hydro
20	CH Chimay	Hydro
21	CH Yanango	Hydro
22	CH Huanchor	Hydro
23	CH Carhuaquero	Hydro
24	CH ARICOTA	Hydro
25	CH CHARCANI	Hydro
26	CH CHARCANI	Hydro
27	CH CHARCANI	Hydro
28	CH MACHUPICCHU	Hydro
29	CH SAN GABAN	Hydro
30	CH CHARCANI	Hydro
31	CH Cañón del Pato	Hydro

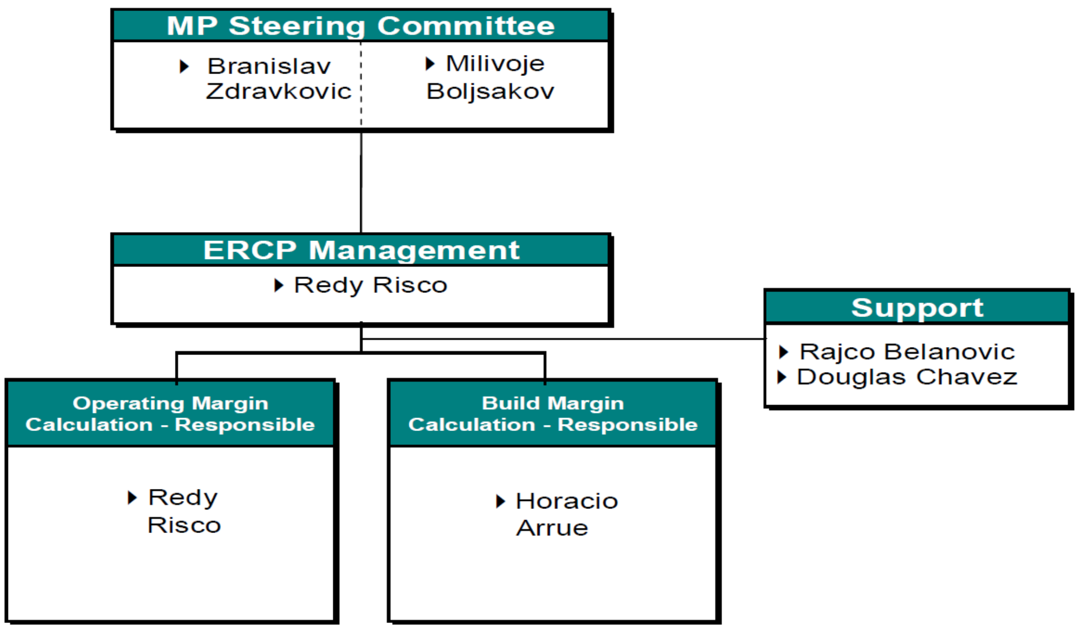
The formula component of each monthly worksheet (W#2–W#13) is given by columns CZ to FD (not shown in this report). Formulas will use data entered in columns D to CY and will bring a resulting DDA-OM. The only data column in this set is EE, which should be filled with the Project's hourly generation. The resulting DDA-OM will show up at the low end of column EE in W# January

VI. Annexes

The ERCP Organizational Structure and Quality Assurance and Control Procedure

Monitoring plan (MP) – Emissions Reductions Calculation Procedure (ERCP)

ERCP Organizational Structure



Monitoring Plan (MP) – Emissions Reductions Calculation Procedure

ERCP Quality Control

Operating Margin Calculation

- *Quarterly Cross-checking*
- *Quarterly Corrective actions*
- *Check calibration of electricity meters, periodically*
- *Make coordination with COES to be able to implement this document*

Data

- The Project hourly generation data:
- *SEIN* units hourly generation data:
- COES public merit order
- Real NECs

Quality of Data Collection

- Which data comes? All of the above
- By what means does it come? By E-mail/ CD
- How does it come? In Excel
- How frequently does it come? Monthly
- From whom does it come? From *COES (Programacion Semanal)*
- To whom does it comes? ERCP Manager

Quality of Data Processing

- Original Data
- Organized Data
- Entered Data
- Processed Data
- Result

- Monthly calculation involves 5 steps
- Follow ERCP
- Beware of alerts – presented in training
- Quarterly cross-check by BM responsible
- Yearly consolidation of C.Margin

Quality of Data Storage

- Prevent Excel versioning problem, by keeping "a new" Excel software package every year in PCs used for the OM and BM calculations
- Keep all data for 2 years after the first crediting period (9 years) –Each responsible should assign a password to his excel spreadsheets
- Save the document with the last date in which an alteration was made, i.e. "OM at xx", so that old versions are kept in disk
- Keep all written documentation in a folder per Margin/Responsible

Quality of Data Delivery

- Provide to the verifier e-mails /CD through which the data provider (COES) delivered the original data
- Provide to the verifier receipt of sales to final clients
- Provide to the verifier all calculations made (all steps of data processing) by showing all preliminary versions of spreadsheets saved in disk