CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 02 - in effect as of: 1 July 2004)

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

20 MW Nasulo Geothermal Project.
Version 3
15 July 2006

A.2. Description of the project activity:

The project is a 20 MW geothermal power plant that is to be located in the municipality of Valencia, Province of Negros Oriental, Republic of the Philippines. The electricity generated by the project is expected to displace grid electricity generated from fossil fuels and reduce GHG emissions by an amount of approximately 74,975 tCO_2e (tonnes of carbon dioxide equivalent) per year for the duration of the project activity. A reduction of approximately 524,825 tCO_2e is forecast for the first 7-year crediting period.

The project is to be developed by Philippine National Oil Company-Energy Development Corporation (PNOC-EDC) and the project lifetime is expected to be 20 years.

The expected load factor for the project is about 80%, resulting in an average generation of 140 GWh of electricity annually. The steam supply will be obtained from the Southern Negros Geothermal Production Field (SNGPF).

The Luzon-Visayas grid suffers from a deficit in electricity supply that is currently met by barge-mounted diesel plants. Using an indigenous and renewable energy source the proposed 20 MW project will obviate the need for equivalent capacity of fossil fuel-based generation to meet the projected power shortfall in Luzon-Visayas by 2007, thus mitigating GHG emissions.

The project will contribute to the country’s sustainable development objectives. On the one hand, it will contribute to the reduction of the country’s reliance on imported fuel and to stabilize electricity costs by developing an indigenous and environmentally friendly energy source. On the other hand, it will contribute towards the global objective of mitigating climate change caused by GHG emissions.

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)**
Philippines (host)	PNOC Energy Development Corporation	No
The Netherlands	**International Bank for Reconstruction and Development** as the Trustee of the Netherlands Clean Development Mechanism Facility	Yes

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 the Philippines.

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

Province of Negros Oriental.

A.4.1.3. City/Town/Community etc:

Dumaguete City (Municipality of Valencia).

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

The project will be located in the Nasuji Area, at the south-western sector of the SNGPF, which lies on the northern flanks of the inactive Cuernos de Negros volcano (1,837m ASL). This volcano is located about 12 km west of Dumaguete City.

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 geothermal project.

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

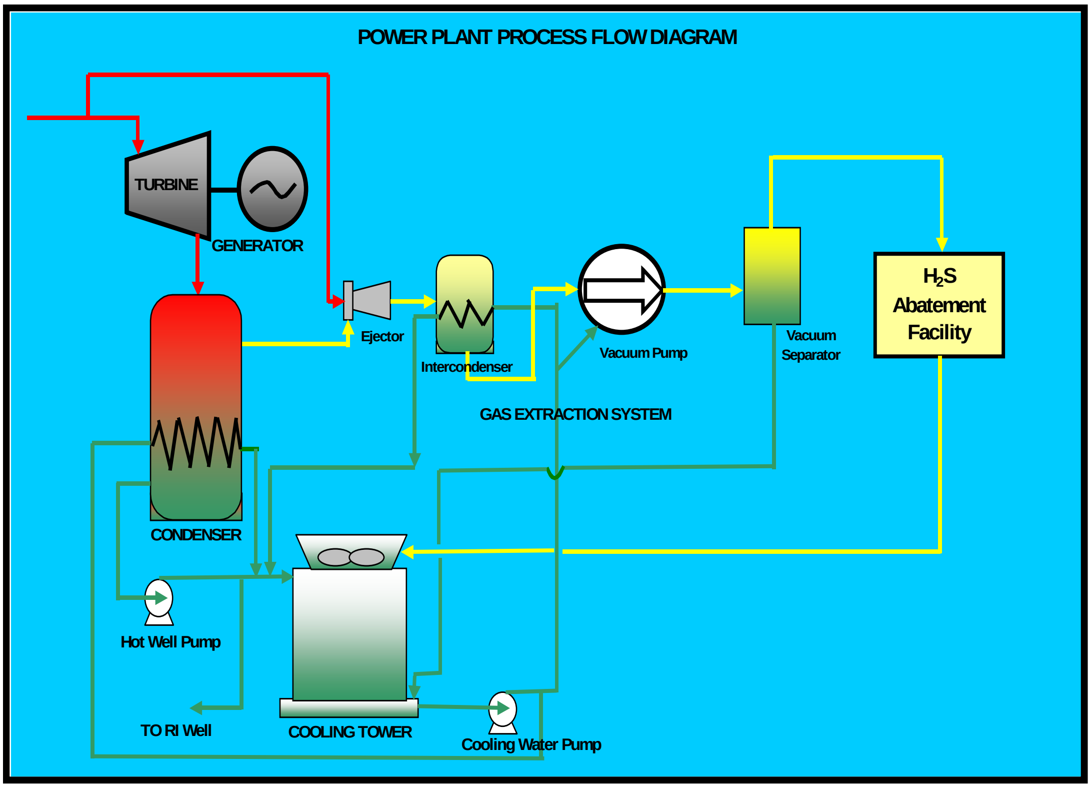
The project includes the following components:

1) Development of a 20 MW geothermal field including the drilling of 1 production well and the construction of the corresponding Fluid Collection and Reinjection System (FCRS) which comprises mainly a piping system with pressure relieving and a reinjection system.

2) Construction, installation and commissioning of a 20 MW geothermal power plant with gas abatement facility.

3) Construction of a switching station at the Nasuji Area to interconnect with Transco's 138 kV transmission lines.

The geothermal steam surges out of the reservoir through the production wells and is collected and directed to a separator vessel which separates geothermal fluids from steam. The separated fluids are sent back to the geothermal reservoir through a specially-constructed reinjection well. The separated steam, on the other hand, is sent to the scrubbers where it is made 99% pure and rid of all contaminants before it is passed on to the turbine to the power plant.
The 20 MW power plant would have the following process flowdiagram:



A.4.4. Brief explanation of how the anthropogenic emissions of anthropogenic greenhouse gas (GHGs) by sources are to be reduced by the proposed CDM project activity, including why the emission reductions would not occur in the absence of the proposed project activity, taking into account national and/or sectoral policies and circumstances:

The project will generate electricity without emitting GHG. Furthermore, this electricity will be supplied to the grid and will displace electricity that is being produced by fossil fuel generation sources.
The project is not as financially attractive as other generation options available in the Philippines. This project also faces a number of barriers that makes implementation difficult without the CDM. Many barriers stem from the fact that the Philippines privatized the electricity generation sector in 2001. On the one hand, concessional financing is no longer available for geothermal developments after privatization. The project sponsor had to tap local financing at much higher rates and shorter tenors (current interest rates are Peso-denominated, at 8% to 9.5% vs. 1-5% for former geothermal plants; tenors of 15 years vs. 25-33 years). Furthermore, local financing has been achieved in form of a peso-denominated loan and the recent devaluation of the local currency has created a financing gap that poses a serious problem for project implementation. The project sponsor is turning to carbon finance to fill such financing gap in the short run. Additionally, the Development Bank of Philippines has included provisions in the loan covenants to instruct the project sponsor to attain CDM status and, once the project becomes registered as a CDM project, the CDM cash flows are pledged as collateral for the loan therefore reducing the risk rate and making the loan possible.[1]
Additionally, geothermal energy faces adverse taxation in the Philippines in the form of royalties that do not prevent the implementation of fossil-fuel alternatives. Other barriers to entry will be explained below.

A.4.4.1. Estimated amount of emission reductions over the chosen crediting period:

Years	**Annual estimation of emission reductions in tonnes of CO_2e**
Feb 2008 - Jan 2009	74,975
Feb 2009 - Jan 2010	74,975
Feb 2010 - Jan 2011	74,975
Feb 2011 - Jan 2012	74,975
Feb 2012 - Jan 2013	74,975
Feb 2013 - Jan 2014	74,975
Feb 2014 - Jan 2015	74,975
Total estimated reductions (tonnes of CO_2e)	524,825
Total number of crediting years	7
Annual average over the crediting period of estimated reductions (tonnes of CO2e)	74,975

A.4.5. Public funding of the project activity:

[1] Loan agreements will be made available to the DOE.

This project has not received any public funding.

SECTION B. Application of a baseline methodology

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

"Consolidated baseline methodology for grid-connected electricity generation from renewable sources ACM0002 Version 6."

The above methodology is hereafter referred to as the "Baseline Methodology".

The Baseline Methodology will be used in conjunction with the approved monitoring methodology ACM0002 Version 6 ("The Monitoring Methodology").

B.1.1. 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 following conditions that are stated in the Baseline Methodology (ACM0002 Version 6):

- The project supplies electricity capacity addition (20 MW) from a geothermal source;
- The project is not an activity that involves switching from fossil fuels to renewable energy at the project site;
- The electricity grid is clearly identified (as Luzon-Visayas grid) and information is available on the characteristics of the grid;

B.2. Description of how the methodology is applied in the context of the project activity:

In accordance with the Baseline Methodology, the Combined Margin (the average of the Operating Margin and Build Margin) is deemed to best represent what would occur in the absence of the project. The baseline scenario is the amount (and type) of electricity that would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources. The project boundary considered is the Luzon-Visayas grid. Emission reductions (ER) will be claimed based on the following formula:

$ER_y = BE_y - PE_y - L_y$

Where:
ER_y are the emission reductions by the project activity
BE_y are the baseline emissions
PE_y are the project emissions
L_y are emissions due to leakage

No leakage emissions have been identified for the project (L_y=0). However, as a geothermal activity, the following project emissions (PE_y) will have to be taken into account:

1) Fugitive emissions of carbon dioxide and methane due to release of non-condensable gases from produced steam.

2) Carbon dioxide emissions resulting from combustion of fossil fuels related to the operation of the geothermal power plant.

The project ERs are calculated based on the following steps:

STEP 1 – Calculate the Operating Margin (OM) emission factor
STEP 2 – Calculate the Build Margin (BM) emission factor
STEP 3 – Calculate the baseline emission factor
STEP 4 – Calculate the project emissions
STEP 5 – Calculate project ERs

STEP 1 – Calculate the OM emission factor

The Simple OM method from the Baseline Methodology is applicable to the project because the data required for using the Dispatch Data Analysis Method and the Simple Adjusted OM Method is not publicly available in the Philippines. Furthermore, to apply the Simple OM method, low cost/must-run resources have to constitute less than 50% of total grid generation in the 5 most recent years. In 2004, 2003, 2002, 2001 and 2000 the generation by low cost/must-run plants constituted less than 50% of total generation by all plants connected to the Luzon-Visayas grid. Therefore the Simple OM Method from the baseline Methodology is applicable to the project.

The Simple OM emission factor is calculated *ex ante* as the generation-weighted average emissions per electricity unit (tCO_2e/MWh) of all generating sources serving the system, for the three most recent years in which grid data is available at the time of PDD submission, not including low-operating cost and must-run power plants (geothermal and hydro in this case). The following formula would apply:

$$EF_{OM,simple,y} = \frac{\sum_{i,j} F_{i,j,y} \cdot COEF_{i,j}}{\sum_{j} GEN_{j,y}}$$

Where:
$F_{i,j,y}$ is the amount of fuel i (in a mass or volume unit) consumed by relevant power sources j in year(s) y,
j refers to the power sources delivering electricity to the grid, not including low-operating cost and must-run power plants,
$COEF_{i,j\,y}$ is the CO_2 emission coefficient of fuel i (tCO_2e / mass or volume unit of the fuel), taking into account the carbon content of the fuels used by relevant power sources j and the percent oxidation of the fuel in year(s) y, and
$GEN_{j,y}$ is the electricity (MWh) delivered to the grid by source j.

Following the Simple OM method the OM emission factor that has been obtained is **0.7549 tCO_2e/MWh**[2]

STEP 2 – Calculate the BM emission factor

The BM is defined in the Baseline Methodology as the generation-weighted average emission factor (tCO2e/MWh) of a sample of power plants. This sample of power plants consists of the 5 power

[2] See more in detail explanation in E.4.

plants that have been built most recently or the power plants capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently. Of these two options, the sample group that comprises the larger annual generation has to be chosen.

The BM emission factor will be calculated *ex ante* and be based on the most recent information available at the time of PDD submission (Option 1 in the Baseline Methodology). The last year in which information is available for this group of plants is 2004.

The formula to apply to the selected sample is:
*EF_BMy (tCO2e/MWh) = [∑I,m Fi,m,y,*COEFi,m] / [∑mGENm,y];*
m = plants of the selected sample, *F* = their generation in MWh, *COEF* = their tCO2e/MWh factor, *GEN*= total sample generation.

Following the formula above, the BM emission factor that has been obtained is **0.355 tCO2e/MWh[3].**

STEP 3 – Calculate the baseline emission factor

The baseline emission factor is the weighted average of the OM emission factor and the BM emission factor. The default weight of the OM and BM emission factors (50%: 50%) is used.

CM= 0.5*OM+ 0.5*BM
CM= 0.5*(0.7549) + 0.5*(0.355) = **0.555 tCO2e/MWh**

STEP 4 – Calculate the project emissions

The following project emissions will have to be measured:

1) Fugitive emissions of carbon dioxide and methane due to release of non-condensable gases from produced steam. With the following formula:

$$PES_y = (W_{main,CO2}+W_{main,CH4}*GWP_{CH4})*M_{s,y}$$

Where:

PES_y are the project emissions due to release of carbon dioxide and methane from the produced steam during the year y
$W_{main,CO2}$ and $W_{main,CH4}$ are the average mass fractions of carbon dioxide and methane in the produced steam
GWP_{CH4} is the global warming potential of methane
$M_{s,y}$ is the quantity of steam produced during the year y
Applying the formula we obtain PES_y = 2,053 tCO2e

2) Carbon dioxide emissions resulting from combustion of fossil fuels related to the operation of the geothermal power plant ($PEFF_y$)

[3] See more in detail explanation in E.4.

A 20 Mw plant uses a 5 Mw diesel-powered gen set during an average of 168 hours a year. Considering a conservative emission factor for the diesel-powered gen set of 0,8 tCO2e/MWh the estimated CO2 emissions are 672 tCO2e [4].

STEP 4 – Calculate project ERs

The estimated ERs per year for the project are obtained from the following formula:

$ER_y = BE_y – PES_y – PEFF_y – L_y$

BE_y = CM* (Estimated Annual Project Generation in MWh) = 0.555 tCO2e/MWh * 140,000 MWh = 77,700 tCO2e
PES_y = 2,053 tCO2e
$PEFF_y$= 672 tCO2e
L_y = 0

ER_y = 77,700 tCO2e - 2,053 tCO2e – 672 tCO2e –0 = **74,975 tCO2e or 81,009 ERs**

The ERs estimated for the first crediting period are:
Estimated ERs for the first crediting period = 74,975 tCO2e/yr* 7 yrs = **524,825 tCO2e** or Estimated ERs.

B.3. 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:

The following steps from the "tool for the demonstration and assessment of additionality" are 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
STEP 3 – Barrier Analysis
STEP 4 – Common Practice Analysis
STEP 5 – Impact of CDM Registration

STEP 0 – Preliminary screening based on the starting date of the project activity

The project's construction will start in December 2006. The sponsor PNOC-EDC stated its intention to apply for carbon finance assistance when they submitted a Project Idea Note to the World Bank's Carbon Finance Business Unit in February 2004. Up to date the project is still finishing implementation arrangements including some aspects of financing.

STEP 1 – Identification of alternatives to the project activity consistent with current laws and regulations

Sub-step 1a – Define alternatives to the project activity

[4] Source: project sponsor from real data collected from NPC plants at the Palinpinon Geothermal Field

PNOC-EDC's traditional business area is steam field development. It has never constructed, owned or operated a geothermal power plant. The three plausible scenarios from among which the baseline scenario should be selected are:

1) Implement the project as a geothermal steam field plus a geothermal power plant operation without CDM assistance,
2) Implement the project as a natural gas plant,
3) Not to implement the project

We consider the alternative of implementing the project as a natural gas plant as the use of this type of technology has recently attracted considerable investments in the Philippines.

Sub-step 1b – Enforcement with applicable laws and regulations

As described above, the project can be implemented in two different ways or not at all.

The Electric Power Industry Reform Act of 2001 (EPIRA) states in its Section 6 that "Generation of electric power, a business affected with public interest, shall be competitive and open". This provides PNOC-EDC with an opportunity to take part in the electricity generation activity in the Philippines.

Thus all scenarios will be in compliance with applicable laws and regulations.

STEP 2 – Investment Analysis

Sub-step 2a: Determine appropriate analysis method

The CDM project activity generates financial and economic benefits other than CDM related income, thus the simple cost analysis does not apply. In order to determine whether the proposed project is economically or financially less attractive than the other alternatives without the revenue from the sale of CERs, Option III – "Apply benchmark analysis", is completed below.

Sub-step 2b - Option III: Apply Benchmark Analysis

The two indicators that will be used are:

1) Project IRR
2) Project Investment Cost

1) Project IRR

Project IRR is a suitable financial indicator for the project and is compared to a calculated benchmark which is the Discount Rate that represents the returns international investors or borrowers expect in the Philippines.

2) Project Investment Cost

The project investment cost is a suitable indicator to measure the attractiveness of a project. Here it will be used as indicator to assess whether the project developer has chosen the most attractive alternative to develop this electricity generation project.

The investment cost of the project will be compared to the investment cost of a natural gas plant, as this type of technology has gained considerable importance in the last years in the Philippines and currently represents an interesting option for electricity generation. This is demonstrated by the fact that three natural gas plants (Santa Rita, Ilijan and San Lorenzo) have been constructed and came in operation (totalling a generation capacity of 2,700 MW) since 2001.

The indicator will be expressed in $US/MW.

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

1) Project IRR

Project IRR: the table below presents the main data used in the IRR calculation for the project. The calculation was conducted in a conservative manner and all assumptions are listed below in order to maintain a transparent approach.

ITEM	VALUE
Financial Details	
Foreign exchange rate	56.5 PHP/1 US$
Initial investment cost	40,219,000 US$
Electricity Price	0.058 US$/kWh (PHP 3.26/kWh)
Electricity sales (140 GWh/year)	8,087,108 US$
Project life	20 years
Expenses	
O&M costs/yr	3,180,000 US$
Project IRR	**9.65%**

Source: Project Sponsor

Data assumptions:

- The costs for equipment and plant were supplied by the project developer based on quotes and current prices.
- The electricity generated will be sold in the spot market once created (the price used for the IRR calculation is based on the tariff set by the government)
- The expected life of the equipment is approximately 20 years.
- The project developer estimated the O&M costs.

The Discount Rate: it is calculated using the Capital Asset Pricing Model (CAPM) formula, as determined by Brealy and Myers in their book “Principles of Corporate Finance”.[5] The CAPM formula establishes that a return on an asset (r) equals the risk free return (rf) plus the ß (Beta) of that asset times the risk market premium (rm-rf). We add the country-specific risk premium (CRP) to reflect the minimum expected returns from international investors or borrowers in the Philippines

[5] .“Principles of Corporate Finance”, Richard A. Brealy and Stewart C. Myers, 5th Edition, McGraw-Hill, p180

$$r = r_f + ß(r_m - r_f) + CRP$$

where:

- r_f = 5.04%; average yield of the 20-year Treasury Bonds for the year 2004 (Federal Reserve System, information released on 03/07/2005)
- ß = 0.47; beta of the electric utility sector in the US (Brealy and Myers, p.219)
- $(r_m - r_f)$ = 13.44%-5.04% = 8.4%; traditional returns on stock investments for the last 69 years (Brealy and Myers, p.180)
- CRP = 4.17%; spread of the bond Phil 2017 as of 16 February 2005 (Source: Asia Bond Indicators – Asia Development Bank).

Therefore a conservative[6] Discount Rate to be used as benchmark to compare with the project IRR is:

r = 5.04% + (0.47*8.4%) + 4.17% = 13.158% = **13.2%**

Comparison:

The Project IRR is compared to the benchmark to examine the financial attractiveness of the project. The project IRR is estimated to be **9.65%**, which is considerably lower than the project's benchmark **13.2%** Low IRR, compared to the hurdle rate, indicates that the project is not financially attractive without CDM assistance. The low return does not justify taking the high risks associated with implementing this new renewable energy project.

2) Project Investment Cost

The information contained in the table below shows the cost range of installing 1 MW of a combined cycle natural gas plant and compares this cost with the cost of installing 1 MW of Nasulo's geothermal plant.

The turnkey cost includes generation set cost, the civil works and the installation costs.

Technology Cost Comparison		
	Cost of a Combined Cycle Gas Turbine	Nasulo Turbine Cost
Turnkey Cost ($/MW)	450,000 to 950,000	1,433,500

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

Comparison:

Taking into account the "Gas Turbine Engineering Handbook" written by Meherwan P. Boyce, the turnkey cost for Nasulo's turbine ($/MW) appears to be between 51% and 218% higher than for a combined cycle gas turbine.

It is clearly demonstrated that taking into account the investment cost, building a natural gas plant is more cost-effective, and thus the preferred choice from a rational investor's point of view, than building a geothermal plant.

[6] It is conservative because it uses US returns on US public utilities and the US stock market. The Philippine markets are much more volatile. Also anecdotical evidence suggests that expectations of international equity investors for the Philippines are higher than 20% as in many other emerging markets.

Furthermore, Philippines has recently discovered natural gas fields and the Government wants to develop its internal natural gas market in order to increase the country's energy self-sufficiency. With this purpose, the Government has developed a "Natural Gas Policy and Regulatory Framework" which makes investment in new natural gas generation plants much more attractive for investors than the investment in geothermal plants.

The case of the Ilijan natural gas plant is a good example of the Government support to the development of the natural gas market. Ilijan entered into a take-or-pay contract for the purchase of natural gas with the Shell Exploration B.V./Occidental Philippines, Inc. Consortium, which was assigned the service contract to exploit the Camago-Malampaya natural gas reservoir. This take-or-pay- agreement is guaranteed by the Philippine Government.

Sub-step 2d –Sensitivity Analysis

The following assumptions are established to examine whether the conclusion regarding the financial attractiveness of the project are robust:

a) Project IRR

As shown in the table below, if the investment cost of the project was 15% less than expected, the project IRR would be 12,1%. This is still below the benchmark (13.2%).

In the case that the electricity tariff was 15% higher than it is now, the project IRR would be 13.1%, which is also below the benchmark (13.2%).

With a 10% more electricity production, the project IRR would be 12,0%, which again is below the benchmark (13.2%).

Finally, if the operation and maintenance costs was 10% less than expected, the project IRR would be 10.6%.This is far below the benchmark (13.2%).

Sensitivity Analysis	+15% Inv.	-15% Inv.	+15% Tariff	-15% Tariff	+10% Production	-10% Production	+10% O&M cost	-10% O&M cost
Project IRR	7,7%	12,1%	13,1%	5,9%	12,0%	7,2%	8,7%	10,6%

Source: World Bank elaboration

b) Project Investment Cost

Combined Cycle Gas Turbine	Turnkey Cost ($/MW)
Average cost	**700,000**
Average cost - 20%	560,000
Average cost - 10%	640,000
Average cost + 10%	770,000
Average cost + 20%	840,000
Nasulo Turbine	**1,433,500**

Source: World Bank elaboration

In this table, the average cost of the combined cycle gas turbine (taken from the Technology Cost Comparison table above) is compared to the cost of Nasulo's turbine. Furthermore, an increase/decrease of up to 20% is considered for the cost of the combined cycle gas turbine in order to see how a change in the cost affects the attractiveness of the natural gas technology against Nasulo's technology.

The results show that even in the most conservative assumption (average cost +20% for the gas turbine), the cost of Nasulo's turbine is always higher.

STEP 3 – Barrier Analysis

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

The main identified barriers are:

1. *Cheaper cost of thermal energy had an impact in geothermal power developments after privatization*

Geothermal plants in the Philippines face stiff competition from cheaper thermal technologies. Following the initiation of the privatization process by EPIRA in 2001 no geothermal project has been developed in the Philippines. Geothermal technology is not the least cost technology in the market[7]. The arrival of the natural gas pipeline to Southern Luzon has marked the beginning of the development of large natural gas-fired power plants.

Since 2001, three natural gas plants (Santa Rita, Ilijan and San Lorenzo) have been constructed and put in operation by Independent Power Producers (totalling a generation capacity of 2,700 MW). In contrast, Mindanao II, which started operating in 1999 (that is before the EPIRA), is the most recent geothermal plant built in the Philippines.

2. *Royalties on indigenous energy sources vs. imported fossil-fuels*

The Philippines Government maintains a 60% royalty on net proceeds from indigenous energy sources (geothermal steam, oil and gas)[8] while imported fossil fuels are charged a mere 3-5% tariff to promote cross-subsidies to the transport sector. NPC, the largest state-owned generator, imports fossil fuels tax free[9]. This circumstance positions coal-fired power plants among the cheapest options in the country. EPIRA pledged in 2001 to level the playing field (section 35), but to date this royalty on geothermal sources has not been lowered nor removed despite calls from electricity generators. This is one of the main barriers responsible for the impasse in geothermal development in the Philippines since EPIRA entered into force.

3. *Government's support to the development of the natural gas market*

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[7] As shown in Step 2 above, natural gas is generally a much cheaper alternative. In particular geothermal is clearly not least cost vs. coal in the Philippines as shown in several World Bank studies prepared for GEF in the financing of the Leyte-Luzon geothermal project in 1994 (Leyte-Luzon Geothermal Project, Project Appraisal Document, Annex 21, 1994)

[8] Presidential Decrees 87 (Dec 31, 1972) and 1442 (June 11, 1978).

[9] "Energy Products Taxation in Asian Economies", Miwilda M Guevara, 2004.

The Government of Philippines is promoting the development of the country's natural gas market (since new natural gas fields were discovered), which has had a direct negative effect on the development of other type of electricity generation technologies, particularly renewables. If investing in a natural gas plant is economically more attractive for a private investor than investing in a geothermal plant, it is obvious that the plants most likely to be developed in the country will include mostly natural gas

The case of the Ilijan natural gas plant is a good example of the Government's support to the development of the natural gas market. Ilijan entered into a take-or-pay contract for the purchase of natural gas with the Shell Exploration B.V./Occidental Philippines, Inc. Consortium, which was assigned the service contract to exploit the Camago-Malampaya natural gas reservoir. This take-or-pay- agreement is guaranteed by the Philippine Government.[10]

4. *Concessional financing no longer available*

Concessional financing is no longer available for geothermal developments after EPIRA. For PNOC-EDC, Nasulo is the first geothermal project that is being financed by a local bank. This loan has a higher rate and shorter tenor than the usual ODA loan that were available before EPIRA (interest rates are Peso-denominated, at 8%-9.5% versus 1%-5% for former geothermal plants; tenors of 15 years versus 25-33 years for former geothermal plants)[11].

Furthermore, PNOC-EDC has made public its intention to be privatized (March 2005), which will make this type of financing permanently unavailable.

An example of concessional financing needed to help geothermal technology to be competitive is the last geothermal power plant built in the country, the Leyte-Luzon geothermal project, also in the Visayas, and promoted by PNOC-EDC. It was financed by the World Bank with concessional terms, and was also given a $30 million grant from GEF on the grounds of not being a least-cost solution[12]. That type of financing opportunity is lost for geothermal energy in the Philippines since privatization of the sector (and privatization of PNOC-EDC, the only steam-field developer in the country).

5. *Barriers to investment in the Visayas*

The Visayas Islands are not the preferred choice for investors The last plant built in that grid was in 1996[13]. So for the last 9 years no other power plant has been built in that part of the country. The current electricity shortages in the islands are now being mitigated by transferring diesel power barges from Luzon[14].

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[10] This incentive is stated by the Government in the Administrative Order No. 381.

[11] Evidence showing previous loan terms for PNOC-EDC geothermal developments can be furnished to the DOE.

[12] Leyte-Luzon Geothermal Project, Project Appraisal Document, Annex 21, 1994, World Bank. The rational for this GEF grant included not only proof of non least-cost status vs. coal, but also a calculation of the GHG emission. reductions from the project. For illustration purposes, the GEF grant would contribute at a rate of $1.6 per ton of CO2 reduced.

[13] The Leyte-Luzon Geothermal Project was the last power plant built in the Visayas. This project was also responsible for the interconnection Luzon-Visayas, therefore converting the two grids into the same one.

[14] Pinamucan Diesel Power Barge is scheduled to be transferred from Luzon to Visayas in 2005 (Power Development Plan 2005-2014, Department of Energy, Republic of Philippines, page 26)

6. *Devaluation impact in financing creates a financing gap*

Local financing has been achieved in the form of a peso-denominated loan and the recent devaluation of the local currency has created a financing gap (of around 4%) that poses a serious problem for project implementation. Project sponsor is turning to carbon finance to cover such financing gap in the short run.

7. *Barriers of Financing: Bank covenants linked to CDM income*

The lending bank has made the financing somewhat contingent on the project attaining CDM status. Without the CDM, the project would have additional difficulties getting financed.[15]

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

The above-described barriers do not apply to cheaper fossil fuel-fired power plants. The most plausible scenario would be not to implement the project since lack of financing would make it impossible. The project sponsor urgently need to find additional funding in order to cover the financing gap and looks to carbon finance income as such as source of much-needed financing.

The evidence after privatization is already available, given that 2,780 MW of natural gas fired power plants have been built since 2001. In the 2001-2003 period, 87% of new additions were from thermal sources vs. from clean energy. And the prospects for renewable energy in Philippines confirm this trend: the Indicative Power Development Plan of the Philippine Government predicts that out of the 7,800 MW expected to be installed in the country from 2005 to 2015, 91.6% will be coming from fossil-based thermal (mainly natural gas—80%—and coal—11.6%)[16].

No geothermal projects have been built since EPIRA was approved.

STEP 4 – Common Practice Analysis

Sub-step 4a – Analyze other activities similar to the proposed project

The proposed project activity is a first-of-a-kind activity in the Philippines after privatization started with the EPIRA in 2001.

The structure of the Philippines power industry before 2001 gave the National Power Corporation (NPC) a monopoly to generate its own electricity or to buy it from IPPs (Independent Power Producers) by means of PPAs (Power Purchase Agreements). Geothermal power development had been a publicly-sponsored activity in the Philippines and the result of strategic power policy decisions in exploiting local natural resources. In that regard, despite the non-least cost status of this renewable energy technology, two public companies were in charge of sharing that non-economic burden. On the one hand PNOC-EDC was in charge of prospecting, drilling and managing the steam-field production. On the other hand, PNOC-EDC sold the steam to NPC generating plants (or more recently to private IPPs on Build, Operate and Transfer (BOT) regimes who in turn would have a power purchase agreement with NPC). Both PNOC-EDC and NPC could afford to have non-economic assets thanks to the counter-balancing effect of other cheaper technologies in their portfolios.

[15] The loan agreements will be made available to the DOE.

[16] Power Development Plan 2005-2014, Department of Energy, Republic of Philippines, Annex 5

The recent privatization process has changed this regulatory framework and therefore the common practice.

With the implementation of EPIRA the NPC "shall not incur any new obligations to purchase power through bilateral contracts with generation companies and other suppliers" (Section 47.(i) of EPIRA). Currently, NPC has lost its mandate to develop new generation and to buy power. PNOC-EDC therefore cannot split the least-economic burden with its traditional public partner. Since no other private generator is stepping up to the plate, the project sponsor has decided for the first time to also develop, own, manage and operate the power generation plant.

As a consequence, the project sponsor is facing a number of challenges that are not common practice in traditional geothermal developments in the Philippines today:

- It's the first time in the Philippines that steam producer and power generator is the same company therefore absorbing the entire economic burden, which makes that technology financially unattractive.
- This increased risk has financing consequences: access to traditional concessional financing is now limited and project sponsor had to resort to private sector financing further hindering the viability of the project activity.
- Current regulation no longer allows for PPAs in the Philippines with NPC, so the sponsor will have to look for a PPA in the private sector or take the risk of selling all its output at the wholesale electricity spot market (WESM). Nasulo will be one of the first plants in the Philippines to become a merchant plant.

Sub-step 4b –Discuss any similar option occurring

No similar activities are currently observed or are commonly carried out by other sponsors, so the claim that the proposed activity is financially unattractive is not called into question.

PNOC-EDC is also currently developing a similar geothermal development called Northern Negros Geothermal Project, under similar terms and structure as the proposed activity. The sponsor is also seeking to attain CDM status in order to take the project further. Application for Carbon Finance assistance was also submitted through the World Bank's Carbon Finance Business.

We can conclude that the project is not common practice, but a very unusual occurrence whose existence is endangered without attaining CDM status. Without carbon credits, the future of geothermal energy in the Philippines is questionable.

STEP 5 – Impact of CDM Registration

The approval and registration of the project activity as a CDM activity will enable the project to be undertaken as the bank has made the recommendation for the project to attain CDM status.

Considering the price of US$ 5.63[17] per tCO_2e, the registration of the project as a CDM activity has a considerable impact on the project's IRR. Without the CER income the IRR is 9.65 %, but with the CER income the IRR goes to 11.16 %.This is considered quite low but it, nonetheless, makes the investment in the project more attractive than without the CDM incentive.

[17] Weighted average price given in the study "State and Trends of Carbon Market 2005", The World Bank.

B.4. Description of how the definition of the project boundary related to the baseline methodology selected is applied to the project activity:

In the ER calculations the following GHG are taken into account:

- CO_2 emissions from electricity generation in fossil fuel fired power that is displaced due to the project activity
- CO_2 and CH_4 emissions from non-condensable gases contained in geothermal steam and CO2 emissions from combustion of fossil fuels required to operate the geothermal power plant

The spatial extent of the project boundary includes the project site and all power plants connected physically to the Luzon-Visayas grid.

The Luzon-Visayas grid is not interconnected to any other grid, for that reason there can't be any imports or exports of electricity from or to the Luzon–Visayas grid. The closest grid to the Luzon-Visayas grid is the Mindanao grid and the Government of Philippines is planning to build an interconnection between both grids in the future. Therefore imports and exports will be monitored at the beginning of every crediting period.

B.5. Details of baseline information, including the date of completion of the baseline study and the name of person (s)/entity (ies) determining the baseline:

The baseline study was completed in March, 2005 by:

Francisco Fernandez-Asin
Carbon Finance Business
World Bank
Washington DC
USA
E-mail: ffernandezasin@worldbank.org

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:

12/2006.

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

The project is expected to have a minimum operating life of 20 years.

C.2 Choice of the crediting period and related information:

C.2.1. Renewable crediting period

C.2.1.1. Starting date of the first crediting period:

1 February 2008.

The expected date of commissioning is given as the starting date of the first crediting period. Should the plant construction/commissioning be delayed, the starting date of the crediting period will be delayed accordingly.

C.2.1.2. Length of the first crediting period:

Seven (7) years with the option of two renewal periods.

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

C.2.2.2. Length:

SECTION D. Application of a monitoring methodology and plan

D.1. Name and reference of approved monitoring methodology applied to the project activity:

"Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources (ACM0002 Version 6)"

The above methodology is hereafter referred to as the "Monitoring Methodology".

D.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 following conditions that are stated in the Monitoring Methodology (ACM0002 Version 6):

- The project supplies electricity capacity addition from geothermal source;
- The project is not an activity that involves switching from fossil fuels to renewable energy at the project site;
- The electricity grid is clearly identified (as Luzon-Visayas grid) and information is available on the characteristics of the grid

The following variables will be monitored as stipulated by the Monitoring Methodology:

- Electricity generation from the project (double checking through quality control/assurance procedures).
- Fugitive emissions of carbon dioxide and methane due to release of non-condensable gases from produced steam.
- Carbon dioxide emissions resulting from combustion of fossil fuels related to the operation of the geothermal power plant.
- The latest Luzon-Visayas grid data supplied by the Philippine Department of Energy is utilized for calculation of the simple OM *ex ante* based on the most recent 3 years of actual data.

D.2. 1. Option 1: Monitoring of the emissions in the project scenario and the baseline scenario

D.2.1.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:

ID number *(Please use numbers to ease cross-referencing to D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1.	Mass quantity	Quantity of steam produced during the year y	t	m	daily	100%	electronic	See Note 1 in the ERCP Quality Control "Calculation of Project Emissions" (in the Annexes of the Monitoring Plan)
2.	Mass fraction	Fraction of CO2 in produced steam	tCO2 / t steam	m	monthly	100%	electronic	See Note 2 in the ERCP Quality Control "Calculation of Project Emissions" (in the Annexes of the Monitoring Plan)
3.	Mass fraction	Fraction of CH4 in produced steam	tCH4 / t steam	m	monthly	100%	electronic	See Note 2 in the ERCP Quality Control "Calculation of Project Emissions" (in the Annexes of the Monitoring Plan)
4.	Mass quantity	Quantity of steam generated during well testing	tCO2 / t steam	m	daily	100%	electronic	See Note 1 in the ERCP Quality Control "Calculation of Project Emissions" (in the Annexes of the Monitoring Plan)
5.	Mass fraction	Fraction of CO2 in steam during well testing	tCO2 / t steam	m	as required	100%	electronic	See Note 2 in the ERCP Quality Control "Calculation of Project Emissions" (in the Annexes of the Monitoring Plan)
6.	Mass	Fraction of	tCH4 /	m	as	100%	electronic	See Note 2 in the ERCP Quality Control "Calculation

	fraction	CH4 in steam during well testing	t steam		required			of Project Emissions" (in the Annexes of the Monitoring Plan)
7.	Fuel quantities	Amount of fossil fuels used for the operation of the geothermal plant	Mass or volum e	m	monthly	100%	electronic	
8.	Emission factors coefficient	CO2 emission coefficients of fossil fuels types used for the operation of the geothermal plant	tCO2 / mass or volum e unit	m	As required	100%	electronic	

D.2.1.2. Description of formulae used to estimate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

See Section E.1 for project emissions calculation.

D.2.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions by sources of GHGs within the project boundary and how such data will be collected and archived :

ID number *(Please use numbers to ease cross-referencing*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

to table D.3)				(e),				
1.	Electricity supplied to the grid by the project	TRANSCO	MWh	Directly measured	hourly measurement and monthly recording	100%	electronic	Electricity supplied by the project activity to the grid. Double check with information registered by TRANSCO
2.	CO_2 emission factor of the grid	Calculated	tCO_2e /MWh	c	At the beginning of each crediting period	100%	electronic	Calculated ex ante as a weighted sum of the OM and BM emission factors at the start of each new crediting period
3.	CO_2 OM emission factor of the grid	Calculated	tCO_2e /MWh	c	At the beginning of each crediting period	100%	electronic	Calculated ex ante by the Simple OM method
4.	CO_2 BM emission factor of the grid	Calculated	tCO_2e /MWh	c	At the beginning of each crediting period	100%	electronic	Calculated ex ante with data on fuel consumption and electricity generation of the last 7 plants built in the Luzon Visayas grid
5.	Identification of generation sources (aggregated per fuel type) for the OM	PDOE (Philippine Department of Energy)	Text	e	At the beginning of each crediting period	100% of set of plants	1. electronic	Identification of power source to calculate OM emission factors

6.	Fuel consumption of fossil fuel generation sources for the last three years available. Aggregated by fuel type.	PDOE	TJ	c	At the beginning of each crediting period	100%	2. electronic	Necessary for the Simple OM calculation (ex ante). Calculated using NECs for the different fossil fuel generation sources and electricity generation data of fossil fuel generation sources for the last three years available aggregated by fuel type
7.	Electricity generation of fossil fuel generation sources for the last three years available. Aggregated by fuel type.	PDOE	MWh	m	At the beginning of each crediting period	100%	electronic	Necessary for the Simple OM calculation (ex ante).
8.	NEC for the different fossil fuel generation sources	Calculated	%	c	At the beginning of each crediting period	100%	electronic	NECs for coal and oil based plants are taken from the “Greenhouse Assessment Handbook (September, 1998)-The World Bank. - NEC for natural gas is taken from "IEA Greenhouse Gas R&D Programme" (www.ieagreen.org.uk)

9.	CO_2 emissions of fossil fuel generation sources for the last three years available. Aggregated by fuel type	Calculated	tCO_2e	c	At the beginning of each crediting period	100%	electronic	Necessary for the Simple OM calculation (ex ante)
10.	CO_2 emission coefficient of each fuel type	IPCC	tCO_2e /TJ	m	At the beginning of each crediting period	100%	electronic	IPCC default values
11.	Identification of power plant for BM	PDOE	Text	e	At the beginning of each crediting period	100% of set of plants	electronic	Identification of plants to calculate BM emission factors (ex ante)
12.	Amount of each fossil fuel consumed by the last 5 power plants built in the Luzon-Visayas grid	PDOE	TJ	m	At the beginning of each crediting period	100%	electronic	The most recent data at the time of PDD production (ex ante)

13.	Electricity generation of the last 5 power plants built in the Luzon-Visayas grid	PDOE	MWh/yr	m	At the beginning of each crediting period	100%	electronic	The most recent data at the time of PDD production (ex ante)
14a.	Electricity imports to the project electricity system	PDOE	kWh	c	At the beginning of each crediting period	100%	electronic	PDOE Data
14b.	CO2 emission coefficient of fuels used in connected electricity systems (if imports do occur)	IPCC	tCO2e/TJ	c	At the beginning of each crediting period	100%	electronic	IPCC default values

D.2.1.4. Description of formulae used to estimate baseline emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

For the calculation of the OM emission factor[18]:

[18] See section E.4 for further detail on baseline emissions calculation

$$EF_{OM,simple,y} = \frac{\sum_{i,j} F_{i,j,y} \cdot COEF_{i,j}}{\sum_{j} GEN_{j,y}}$$

Where:
$F_{i,j,y}$ is the amount of fuel i (in a mass or volume unit) consumed by relevant power sources j in year(s) y,
j refers to the power sources delivering electricity to the grid, not including low-operating cost and must-run power plants,
$COEF_{i,j\,y}$ is the CO2 emission coefficient of fuel i (tCO2e / mass or volume unit of the fuel), taking into account the carbon content of the fuels used by relevant power sources j and the percent oxidation of the fuel in year(s) y, and
$GEN_{j,y}$ is the electricity (MWh) delivered to the grid by source j.

For the calculation of the BM emission factor:

EF_BMy (tCO2e/MWh) = [∑I,m Fi,m,y,*COEFi,m] / [∑mGENm,y];
m = plants of the selected sample, F = their generation in MWh, COEF = their tCO2e/MWh factor,
GEN= total sample generation.

For the calculation of the CM emission factor:

CM= 0.5*OM+ 0.5*BM

For the estimation of the baseline emissions:

Estimated baseline emissions in year y = BE_y = CM* (Estimated Annual Project Generation in MWh)

D. 2.2. Option 2: Direct monitoring of emission reductions from the project activity (values should be consistent with those in section E).

Not applicable

D.2.2.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

D.2.2.2. Description of formulae used to calculate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.):

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D.2.3. Treatment of leakage in the monitoring plan

D.2.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project activity

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

D.2.3.2. Description of formulae used to estimate leakage (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

D.2.4. Description of formulae used to estimate emission reductions for the project activity (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

$ER_y = BE_y - PE_y - L_y$

Where:
ER_y are the emission reductions by the project activity
BE_y are the baseline emissions
PE_y are the project emissions
L_y are emissions due to leakage

D.3. Quality control (QC) and quality assurance (QA) procedures are being undertaken for data monitored

Data *(Indicate table and ID number e.g. 3.-1.; 3.2.)*	Uncertainty level of data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
D.2.1.3.1 - 1	Low	Gather information from Transco to ensure consistency
Others	Low	PDOE, IPCC

D.4 Please describe the operational and management structure that the project operator will implement in order to monitor emission reductions and any leakage effects, generated by the project activity

All monitoring equipment will be installed by experts and regularly calibrated to the highest standards by project staff. It is planned that an online monitoring system will be implemented. PNOC–EDC will appoint an executive to be responsible for all data monitoring / acquisition and recording for CDM purposes.

D.5 Name of person/entity determining the monitoring methodology:

The baseline study was completed in March, 2005 by:

Francisco Fernandez-Asin
Carbon Finance Business
World Bank

Washington DC
USA
E-mail: ffernandezasin@worldbank.org

SECTION E. Estimation of GHG emissions by sources

E.1. Estimate of GHG emissions by sources:

The project will be responsible for:

1) Fugitive emissions of carbon dioxide and methane due to release of non-condensable gases from produced steam. The following formula will apply

$$PES_y = (W_{main,CO2}+W_{main,CH4}*GWP_{CH4})*M_{s,y}$$

Where:

PES_y are the project emissions due to release of carbon dioxide and methane from the produced steam during the year y
$W_{main,CO2}$ and $W_{main,CH4}$ are the average mass fractions of carbon dioxide and methane in the produced steam
GWP_{CH4} is the global warming potential of methane
$M_{s,y}$ is the quantity of steam produced during the year y

Applying the formula we obtain:

PES_y = (7,308 gCO2/ton-steam + 4.320 gCH4/ton-steam*21)*277,484 ton-steam =
= 2,053 x10^6 gCO2e = 2,053 tCO2e[19]

2) Carbon dioxide emissions resulting from combustion of fossil fuels related to the operation of the geothermal power plant ($PEFF_Y$)

A 20 Mw plant uses a 5 Mw diesel-powered gen set during an average of 168 hours a year. Considering a conservative emission factor for the diesel-powered gen set of 0,8 tCO2e/MWh the estimated CO2 emissions are 672 tCO2e [20].

E.2. Estimated leakage:

The project is not responsible for any leakage (L_y=0)

E.3. The sum of E.1 and E.2 representing the project activity emissions:

The project activity emissions are obtained by summing up PES_y, $PEFF_Y$ *and* L_y:

Project Activity Emissions= $PES_y + PEFF_Y + L_y$ = 2,053 tCO2e + 672 tCO2e + 0 = **2,725 tCO2e**

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[19] See annex 3 for further detail and sources

[20] Source: project sponsor from real data collected from the wells tapped for the Nasulo Geothermal Project.

E.4. Estimated anthropogenic emissions by sources of greenhouse gases of the baseline:

In accordance with the baseline methodology, the Combined Margin (the average of the OM and BM) is deemed to best represent what would occur in the absence of the project. The baseline scenario is the amount (and type) of electricity that would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources. The project boundary considered is the Luzon-Visayas grid.

The baseline emission factor is calculated based on the following steps from the baseline methodology:

STEP 1 – Calculate the Operating Margin (OM) emission factor
STEP 2 – Calculate the Build Margin (BM) emission factor
STEP 3 – Calculate the baseline emission factor
STEP 4 – Calculate baseline emissions

STEP 1 - Calculate the OM emission factor

The Simple OM method from the Baseline Methodology is applicable to the project because the data required for calculating the Dispatch Data Analysis Method and the Simple Adjusted OM Method is not publicly available. Furthermore, to apply the Simple OM method, low cost/must-run resources should constitute less than 50% of total grid generation in the 5 most recent years. In 2004, 2003, 2002, 2001 and 2000 the generation by low cost/must-run plants constituted less than 50% of total generation by all plants connected to the Luzon-Visayas grid. Therefore the Simple OM Method from the baseline Methodology is applicable to the project.

The Simple OM emission factor is calculated *ex ante* as the generation-weighted average emissions per electricity unit (tCO2e/MWh) of all generating sources serving the system, for the three most recent years in which grid data is available at the time of PDD submission, not including low-operating cost and must-run power plants (geothermal and hydro in this case). The following formula would apply:

$$EF_{OM,simple,y} = \frac{\sum_{i,j} F_{i,j,y} \cdot COEF_{i,j}}{\sum_{j} GEN_{j,y}}$$

Where:
$F_{i,j,y}$ is the amount of fuel i (in a mass or volume unit) consumed by relevant power sources j in year(s) y,
j refers to the power sources delivering electricity to the grid, not including low-operating cost and must-run power plants,
$COEF_{i,j\,y}$ is the CO2 emission coefficient of fuel i (tCO2e / mass or volume unit of the fuel), taking into account the carbon content of the fuels used by relevant power sources j and the percent oxidation of the fuel in year(s) y, and
$GEN_{j,y}$ is the electricity (MWh) delivered to the grid by source j.

PDOE provided information on aggregated data for electricity generation in the Luzon-Visayas grid for 2002, 2003 and 2004 (by fuel type) and the power output for 2004 of the last 7 plants built in the Luzon-Visayas grid, which generation accounts for the 20% of the total electricity generated in the Luzon Visayas grid in the year 2004.

To calculate the OM emission factor using the Simple OM method we have first to calculate the annual aggregated fuel consumption data per fuel type for 2002, 2003 and 2004. We have used the following data:

- Annual electricity generation per fuel type for the three years (GWh)
- Conservative NEC of the different technologies (%)
- The conversion factor to convert GWh into TJ (3.6 TJ/GWh)

For example, to calculate the aggregated fuel consumption of coal in 2002 we would do the following:

Fuel consumption of coal 2002 (TJ)	=	Coal based electricity generation 2002 (GWh)	x	Conversion factor (TJ/GWh)	/	NEC for coal (%)

The same calculation would have to be done for coal in 2003 and 2004 and for natural gas and oil based in 2002, 2003 and 2004.

Once we have the annual aggregated fuel consumption per fuel type for the three years we calculate the CO2 emission derived from that fuel consumption. Therefore we use the following data:

- IPCC carbon emission factor per type of fuel (tC/TJ)
- IPCC values for “fraction of C oxidized” per type of fuel
- Mass conversion factor (tCO2e/tC)

For example, to calculate the CO2 emissions derived from the coal consumption in 2002 we would do the following:

CO2 emissions of coal 2002 (tCO2e)	=	Fuel consumption of coal 2002 (TJ)	x	IPCC "C emission factor of coal" (tC/TJ)	x	IPCC Fraction of C oxidized of coal	x	Mass conversion factor (tCO2e/tC)

Once we have the CO2 emissions derived from the consumption of coal, oil based and natural gas for the three years we can calculate the OM emission factor:

$$\text{OM emission factor (tCO2e/MWh)} = \frac{\text{CO2 emissions of coal 2002+2003+2004 (tCO2e)} + \text{CO2 emissions of natural gas 2002+2003+2004 (tCO2e)} + \text{CO2 emissions of oil based 2002+2003+2004 (tCO2e)}}{\text{electricity generation fossil fuels 2002+2003+2004 (MWh)}}$$

Following Step 1 we obtain that the OM emission factor for the Luzon-Visayas grid is **0.7549 tCO2e/MWh**

STEP 2 – Calculate the BM emission factor

The Baseline Methodology defines the BM as the generation-weighted average emission factor (tCO2e/MWh) of a sample of power plants. This sample of power plants consists of the 5 power plants that have been built most recently or the power plants capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently. Of these two options, the sample group that comprises the larger annual generation has to be chosen.

The BM emission factor will be calculated *ex ante* and be based on the most recent information available at the time of PDD submission (Option 1 in the Baseline Methodology). The last year in which information is available for this group of plants is 2004.

We take the last 7 plants built as their electricity generation in 2004 (14,080,247 MWh) accounts for just over 20% of the Luzon-Visayas system generation in 2004 (9,774,058 MWh). Without including the Santa Rita CCGT which is the last of the group of seven plants, the electricity generated by the other 6 plants doesn't reach the 20%.

The formula to apply to the selected sample is:
EF_BMy (tCO2e/MWh) = [∑I,m Fi,m,y,*COEFi,m] / [∑mGENm,y];
m = plants of the selected sample, F = their generation in MWh, COEF = their tCO2e/MWh factor,
GEN= total sample generation.

PDOE provided the electricity production of these 7 plants and in order to calculate the BM emission factor we have first to calculate their fuel consumption. We will calculate the fuel consumption using the following data:

- Annual electricity generation of the plant (GWh)
- Conservative NEC of CCGT technology (%)
- The conversion factor to convert GWh into TJ (3.6 TJ/GWh)

For example, to calculate the aggregated fuel consumption of San Lorenzo CCGT we would do the following:

Fuel consumption of San Lorenzo CCGT (TJ)	=	San Lorenzo CCGT electricity generation (GWh)	x	Conversion factor (TJ/GWh)	/	NEC of CCGT (%)

The BM emission factor would then be calculated as follows:

- Converting the fuel consumption of every plant into CO2 emissions. Therefore we use the following data:

- IPCC carbon emission factor per type of fuel (tC/TJ)
- IPCC values for "fraction of C oxidized" per type of fuel
- Mass conversion factor (tCO2e/tC)

Using San Lorenzo CCGT as example:

CO2 emissions of San Lorenzo (tCO2e)	=	Fuel consumption of San Lorenzo (TJ)	x	IPCC "C emission factor of natural gas" (tC/TJ)	x	IPCC Fraction of C oxidized of natural gas	x	Mass conversion factor (tCO2e/tC)

- Adding the CO2 emissions of the 7 plants

- Dividing the sum of CO2 emissions of the 7 plants by the total electricity generation of the 7 plants in that year (14,080,247 MWh)[21]

Following step 2 we obtain that the BM emission factor for the Luzon-Visayas grid is **0.3555 tCO2e/MWh**

STEP 3 – Calculate the baseline emission factor

The baseline emission factor is the weighted average of the OM emission factor and the BM emission factor. The default weight of the OM and BM emission factors (50%: 50%) is used.

CM= 0.5*OM+ 0.5*BM
CM= 0.5*(0.7549) + 0.5*(0.3555) = **0.555 tCO2e/MWh**

STEP 4 – Calculate baseline emissions

The estimated baseline emissions per year for the project are obtained from the following multiplication:
BE_y = CM* (Estimated Annual Project Generation in MWh)

[21] See Annex 3 for further detail.

BE_y = 0.555 tCO2e/MWh * 140,000 MWh = 77,700 tCO2e

E.5. Difference between E.4 and E.3 representing the emission reductions of the project activity:

Project $ER_y = BE_y – PES_y – PEEF_y – L_y$= 77,700 tCO2e – 2,053 tCO2e – 672 tCO2e – 0 = **74,975 tCO2e or 74,975 ER**

E.6. Table providing values obtained when applying formulae above:

Year	**Total baseline emissions (tCO_2e)**	**Total Project emissions (tCO_2e)**	**Emission reductions (tCO_2e)**
Feb 2008 – Jan 2009	77,700	2,725	74,975
Feb 2009 – Jan 2010	77,700	2,725	74,975
Feb 2010 – Jan 2011	77,700	2,725	74,975
Feb 2011 – Jan 2012	77,700	2,725	74,975
Feb 2012 – Jan 2013	77,700	2,725	74,975
Feb 2013 – Jan 2014	77,700	2,725	74,975
Feb 2014 – Jan 2015	77,700	2,725	74,975
TOTAL	543,900	19,075	524,825

SECTION F. Environmental impacts

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

PNOC-EDC has carried out an Environmental Assessment (EA) report for the project. The following were the findings of the EA:

Since the project is basically an optimization of the existing geothermal production field, the scale of activities and new processes involved is expected to be small compared to a full blown geothermal power development. Only minimal incremental environmental impacts are anticipated. The environmentally critical activities are: land clearing and civil works involved in the preparation of the 1-ha power plant site, the 0.5-km access road and the 1.0-ha new re-injection well pad; the repair/drilling of old/new wells; and the operation of the 20MW additional generating capacity. The likely environmental issues include: increased sedimentation from the civil work activities; the handling and disposal of wastes, which include drilling wastes, spent geothermal fluids or brine, cooling tower blow down and sludge; and, the air quality impact of the additional air emissions from the new plant, particularly hydrogen sulphide. The EA provided very comprehensive assessments of the environmental impacts (e.g., geology, hydrology, water quality, aquatic and terrestrial ecology, air quality and socioeconomics). It has identified and addressed both minor actual impacts as well as low probability potential impacts. The following are assessments of the critical environmental issues:

Air Quality- The major air pollutant emitted by geothermal power plants is hydrogen sulphide (H_2S). The air quality monitoring which PNOC-EDC installed for existing power plants, showed that the average ambient level of H2S is 0.017 ppm which is well below the 0.070 ppm government standard for residential area. (Note that the current government occupational standard for H_2S is 10 ppm while the WHO 24-hr guideline value is 0.105ppm). Under the new Philippine Clean Air Law, the SNGPF is designated as a “geothermal airshed”. The airshed concept of the Clean Air Law provides that geothermal projects within the airshed have to comply only with the ambient standards rather than the emission standards. The air quality study using AERMOD (air dispersion modelling system) predicts that emissions from the new power plant will result to a ground level concentration of between 0.008 to 0.042 ppm. Hence, given the background concentration of 0.017 ppm, the expected ambient H_2S concentrations with the new plant fully operating will still be well below the 0.07ppm residential area standard.

Water Quality -The impacts on water quality will be negligible and will likely only be in the form of increased sedimentation from civil works. Contamination of the surface water with geothermal brine is highly unlikely as PNOC-EDC has long adopted the zero discharge scheme (ZDS) in all its geothermal power plants. Under ZDS, liquid wastes from geothermal power generation consisting of (a) drilling wastes, geothermal brine and cooling tower blowdown are injected into designated re-injection wells. The whole system consists of a network of pipes, sumps, thermal ponds and re-injection wells. The geothermal brine and cooling tower blowdown are channelled into the thermal ponds for cooling before they are conveyed by gravity or pumped into the re-injection wells. Drilling wastes are temporarily stored in sumps to allow solid particles to settle before they are conveyed to the re-injection wells. The thermal ponds and sumps also serve as temporary holding ponds in case of re-injection failure. Contamination of groundwater is also unlikely as the sumps and thermal ponds are lined with impervious materials while the wells are cemented and steel-cased up to a depth of 1,600 meters, effectively preventing contact between the geothermal fluid and the potable water aquifer. The reinjection system of the project will be integrated into the existing reinjection system of Palinpinon II.

Land Use and Forest- The project will not adversely affect the forest, as all development activities will be confined within the existing development block which is mostly built-up or grassland with isolated tree species. A tree inventory of the new areas to be opened (i.e. the 1.0-ha reinjection wellpad and 500-meter access road) has counted a total of only 29 trees. All except two of these trees are pioneer tree species or the kind of trees that grow on a logged-over or fallowed area. On the contrary, the continued implementation of the company’s watershed management program is expected to preserve or enhance the forest cover of the geothermal reservation.

Natural Habitat and Protected Areas- The associated infrastructure and civil works activities are not expected to affect critical natural habitats. The 4.1 hectares of land to be opened up is a logged-over or fallowed area. Project documents provided also indicate that the project site does not fall within a protected area. The nearest protected area is the Balinsasayao Twin Lakes which is roughly 3 km from the site.

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

The EA did not identify any significant environmental impacts from the project.

SECTION G. Stakeholders' comments

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

PNOC-EDC conducted consultations with local residents and government officials. It has secured endorsements of the project from the Negros Oriental Provincial Development Council and the Central Visayas Regional Development Council. Copies of the EA were provided to the municipal and the provincial governments while a summary was published in the PNOC-EDC's website. Also, PNOC-EDC has been engaging the barangays, people's organizations, and settlers within the geothermal reservation during the past 10 years on various issues, concerns, developments, and opportunities related to the geothermal field. The Geothermal Field has an active Multisectoral Monitoring Team (MSMT), composed of community representatives, LGUs, NGOs and PNOC-EDC. The MSMT holds regular meetings to review environmental performance of the project. They are also regularly apprised of the activities in the SNGPF.

G.2. Summary of the comments received:

There are no significant social issues associated with the project. The project will not cause involuntary resettlement or displacement of livelihood as there will be no land acquisitions involved and all land developments are confined within the geothermal field. The remaining potential social issues associated with the project are discussed below:

Community Acceptance – The project is received well by the local communities as it is viewed as an addition to the existing geothermal operations which are providing benefits. The key stakeholders of the project are the National Government of the Philippines, the host Local Government Units and residents of Barangay Puhagan, Municipality of Valencia and Province of Negros Oriental. The local governments and residents will benefit from increased royalty receipts and other law-mandated funds from the project. At present, local residents are already benefiting from the royalties and other law-mandated funds from existing Palinpinon I and II projects in the form of subsidized power rates (up to 100% of monthly household consumptions in host barangays), livelihood support, environmental, health and other social development interventions. Apart from these law-mandated benefits, PNOC-EDC has been organizing local communities and providing them with alternative livelihood under its Watershed Management Program. PNOC-EDC has developed very positive and close relationship with the surrounding communities within and outside the geothermal reservation. This was validated by the World Bank's Safeguards Team during the field visit and consultation with the barangay leaders and representatives from the Puhagan Farmers' Association in July 27-28, 2004.

Indigenous Peoples **–** Southern Negros is not a known habitat of indigenous people or cultural minorities. The present residents in the project area are relatively new settlers from the lowland areas who belong to the Cebuano ethno-linguistic stock, the largest mainstream group in the Visayas and Mindanao area. There is also no evidence that the area had been occupied by any indigenous people.

Gender Issues – The project is not expected to significantly alter existing gender equity patterns. The employment profile in the project will generally reflect the differentiated roles of men and women in the Philippine society, i.e. construction and drilling works will generate more jobs for men, while office works will generate jobs for women. It is expected that field-based hiring will be skewed toward male workers. At present, women account for only 3% of personnel in SNGPF but a much higher percentage (20%) at PNOC-EDC's Manila Office. The positive contribution to gender equity would likely be coming from the company's community development efforts. Women had been involved in the company's social forestry and livelihood projects. At present they account for about half (45%) of the 745 members in the 17 farmers' associations. They also tend to be more active in the associations' activities, taking on policy and decision making roles. They already account for more than 60% of the associations' officers. This project promises to increase community development efforts of the company as indicated in its watershed management plan.

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

On Local Employment and Livelihood – PNOC-EDC pledges to continue its policy of giving priority to local residents for jobs in the project. With Nasulo on stream PNOC-EDC plans to expand its Social Forestry Program to reach to more communities within the geothermal reservation and expand livelihood and training support under the newly organized Corporate Responsibility Department. It is also expanding its community development effort to include health and education.

Flexibility in the use of funds – The government-mandated benefits and funds are under the control of the local governments and the Department of Energy. PNOC-EDC has been helping the local governments identifying and implementing development programs using these funds. PNOC-EDC is currently collaborating with Government of the Municipality of Valencia to develop a new community site for the residents of Puhagan many of whom are currently residing in informal dwellings, along the roads and steep slopes near the project facilities.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	PNOC-EDC
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Represented by:	
Title:	Vice President Planning and Control
Salutation:	Mr.
Last Name:	Lim
Middle Name:	
First Name:	Benjamin
Department:	Planning & Control
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Represented by:	
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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

This project has not received any public funding

Annex 3

BASELINE INFORMATION

1) The data and parameters used for the *ex ante* OM calculations are the following:

- Aggregated data for electricity generation in the Luzon-Visayas grid for 2002, 2003 and 2004 obtained from PDOE[22].

Aggregated Luzon+Visayas Energy Generation (MWh)			
	2002	2003	2004
Oil based	5.276.696	5.456.423	6.588.522
Natural gas	8.770.851	13.139.410	12.384.467
Coal	16.127.887	14.938.747	16.194.412
Hydro	2.925.684	3.880.807	4.331.156
Geothermal	9.384.581	8.961.429	9.371.734
total	**42.485.699**	**46.376.816**	**48.870.291**

- -NEC values taken from the "Greenhouse Gas Assessment Handbook" pages 24-25 (The World Bank, 1998) for coal and oil based on one hand and from "IEA Greenhouse Gas R&D Programme" (www.ieagreen.org.uk) for natural gas.

NEC per technology	
Oil Based	35%
Coal	33%
Natural Gas	50%

- In the absence of the specific data for the plants connected to the Luzon-Visayas grid IPCC figures are used for carbon emission factors for fossil fuels and fraction of C oxidized.

[22] The Baseline Methodology allows the use of aggregated data in the case that more disaggregated data is not available.

C Emission Factor (tC/TJ)	
Oil based	20,2
Natural gas	15,3
Coal	25,8
IPCC values	

Fraction of C oxidized	
Oil based	0.99
Natural gas	0.995
Coal	0.98
IPCC Values	

2) The data and parameters used for the *ex ante* BM calculations are the following:

LAST POWER PLANTS BUILT IN LUZON-VISAYAS				
	Year	*Electricity Generated in 2004*	*Fuel consumption in 2004*	*NECs of the coal and the CCGT plants*
Plant Name		(MWh)	(GJ)	
Kalayaan Hydro 3&4	2004	473.840	0	
PMDP	2004	27.930	304.692	0,33
San Roque Hydro	2003	810.773	0	
San Lorenzo CCGT	2002	2.585.960	18.618.914	0,50
Ilijan CCGT -Nat Gas	2002	4.079.781	29.374.425	0,50
Casecnan Hydro	2001	399.280	0	
Sta Rita CCGT	2001	5.702.683	41.059.316	0,50
Total		**14.080.247**	**89.357.347**	

We take the last 7 plants built as their electricity generation in 2004 account for just over the 20% of the Luzon-Visayas system generation in 2004 (9,774,058 MWh).
Source: PDOE

3) The data and parameters used to calculate the fugitive emissions of carbon dioxide and methane due to release of non-condensable gases from produced steam are:

Table 1: CO_2 and CH_4 levels (mg per kg of steam) from wells tapped for Nasulo Geothermal Project

Well name	CO2 mg/kg (weighted average)	CH4 mg/kg (weighted average)
NJ4D	**5,731**	**1.636**
NJ5D	**5,124**	**2.067**
NJ6D	**6,708**	**1.000**
NJ7D	**8,095**	**2.535**
NJ8D	**4,804**	**1.341**
OK6	**13,717**	**20.476**
Weighted average from all wells	7,308	4.320

Source: PNOC-EDC

At steam rate of 2.273 kg/s/Mwe and separator pressure of 0.63 MPaa, Table 2 shows the projected generation of CO_2 and CH_4 from the 20 Mwe power plant at its first to its 25th year of production, assuming at full-load and the levels of gases remain constant[23]:

Table 2: Projected generation of CO_2 and CH_4 from the 20 Mwe Nasulo Geothermal power plant

Years of Production	Amount of steam produced after years of 20 Mwe-production (ton-steam)	CO2 Produced (tons)	CH4 Produced (tons)
1	**277,484**	2,028	1
5	**1,387,418**	10,140	6
10	**2,774,835**	20,279	12
15	**4,162,253**	30,149	18
20	**5,549,670**	40,558	24

Source: PNOC-EDC

[23] These are real measurements taken form wells tapped for the Nasulo Geothermal project following the Approved Consolidated Monitoring Methodology ACM0002 VERSION 6. The final data presented are the weighted average of those emissions. Complete measurement data and calculation procedures have been provided to the DOE

Annex 4

MONITORING PLAN

TABLE OF CONTENTS

I. Background Information

The baseline methodology and monitoring methodology for the Nasulo Geothermal Project ("the project") are in accordance with the approved consolidated baseline methodology ACM0002 VERSION 6, which is applicable to grid-connected electricity generation from renewable sources.

The project's installed capacity and estimated yearly average generation are as follows:

Project name	Installed capacity (MW)	Generation (GWh/yr)
Nasulo Geothermal Project	20	140

Source: The project's feasibility study

The project is a geothermal power plant that is to be located in the municipality of Valencia, Province of Negros Oriental, Republic of the Philippines. The electricity generated by the project is expected to displace grid electricity generated from fossil fuels and reduce GHG emissions by an amount of approximately 74,975 tCO_2e per year for the duration of the project activity. A reduction of approximately 524,825 tCO_2e, is forecast for the first 7-year crediting period.

The spatial extent of the project boundary includes the project site and all power plants connected physically to the Luzon-Visayas grid.

II. Organizational, Operational and Monitoring Obligations

A. Obligations of the Operator

Monitoring the project's performance in terms of ERs achievement requires the fulfillment of operational data collection and processing obligations from the operator. The operator has the primary obligation to calculate the project ERs based on the most recent available information, following the ERs Calculation Procedure ("ERCP") presented in this Monitoring Plan (MP) and to abide to the ERCP Organizational Structure and the ERCP Quality Control presented in the annex section of this MP. Please see annex for both the ERCP Organizational Structure and the ERCP Quality Control.

The ERCP Organizational Structure aims at showing that the ERCP Manager will be the responsible for performing the ERCP, and the MP Steering Committee will be the responsible for supervising the ERCP Manager monitoring work. The ERCP Manager will report to the MP Steering Committee; and both the ERCP Manager and MP Steering Committee coordinately will report to the verifier (when the verification takes place), allowing for a successful verification of the project accounted ERs.

It is planned that an online monitoring system will be implemented allowing for an hourly measurement of the electricity generated by the project. At the same time, these measurements will be compared with the measurements done by the National Transmission Company, TRANSCO

The ERCP Quality Control aims at providing guidance on how to handle monitoring data as to ensure that sufficient and accurate information is made available to the verifier, allowing for a successful verification of accounted ERs. The ERCP Quality Control presented in the annex section of this MP provides guidance on how to trace back the electricity produced by the project from TRANSCO (until a wholesale electricity spot market operator is finally established)[24]. It is responsibility of the operator to enter in agreements with this data-source to ensure that data is made available monthly to the ERCP Manager.

At the same time the ERCP Quality Control establishes how to measure the project activity emissions:

- Fugitive emissions of carbon dioxide and methane due to release of non-condensable gases from produced steam, and
- Carbon dioxide emissions resulting from combustion of fossil fuels related to the operation of the geothermal power plant.

With the data on project electricity generation and the data on project activity emissions, the ERCP Manager will be able to calculate the project ERs.

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. The Certified Emissions Reductions ("CERs") would be granted ex-post verification.

Hourly Data Collection and Monthly Reporting– Parties Involved

TRANSCO or the market operator when it is finally established (Data Provider)	- Should provide monthly to the operator a written proof of the project's monthly generation registered by it.
The operator (Data Processor)	- Should implement and manage the online monitoring system in order to be able to obtain hourly measurements of the electricity produced by the project. - Should keep receipt of electricity sales. - Should perform monthly calculation of ERs following the ERCP. - Should perform the annual report of ERs achieved to the verifier. - Should establish the necessary agreements with TRANSCO to assure that it provides a written report of the project's registered monthly generation.

Source: Own production

II. A of the MP is to be complemented with annexes in mention: the ERCP Organizational Structure and the ERCP Quality Control.

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 consider the project's ERCP as a manual. The ERCP should contain: i) data gathered from TRANSCO's information system and ii) data on the

[24] In this document, "TRANSCO" must be substituted for "wholesale electricity spot market operator", once the latter has finally been established.

project activity emissions iii) data processed by the operator. All data processing should be done in Excel. The ERCP is designed for monthly and yearly calculation, based on final TRANSCO reports and the calculations on the project activity emissions. 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 will be in only 1 spreadsheet to be reviewed by the verifier named Nasulo ERs at "yearly period in question".xls**.** However, as the verifier could require preliminary calculations, the ERCP responsible ("ERCP manager") should keep the name of the file and follow by the date at which the latest adjustment is made, every time he works on the file. Doing so will allow to save old versions in disk and keep them as a record to show to the verifier, if required.

When the ERs calculation for the month is completed, the file should be named Nasulo ERs at "month in question".xls, to allow differentiating scratch versions from the final monthly calculation. Likewise, after the calculation of the ERs of the last month of the year, the file should change its name to Nasulo ERs at "yearly period in question".xls.

The year for the MP will run from the beginning of February to the end of January of the following year. This monthly-filled file will be composed by 3 worksheets:

1. *Worksheet # 1: Original Data from TRANSCO*
2. *Worksheet # 2: Data on Project Activity Emissions*
3. *Worksheet # 3: Organized Data, Processed Data and Result*

1. Worksheet #1: Should contain data as it was handed in, by TRANSCO, through a CD or email, arranged in months. The ERCP manager should not manipulate this data other than copy and paste it from the file it was handed in. The CD or e-mail through which data comes from provider should be kept as proof for the verifier.
2. Worksheet # 2: Should contain data on the project activity emissions, arranged in months, with the formulas that are used to do the calculations.
3. Worksheet # 3: The ERCP manager should put in a column (1 column per month) the monthly project generation and in the same column (but in a different row) the monthly project activity emissions. See the following table as example:

	December	January	February	March	………
Electricity generation (MWh)					
Project emissions (tCO2e)					

In the same worksheet the ERCP manager should calculate monthly ERs (measured in tCO2e) by using the following formula:

Monthly ERs (tCO2e) = monthly project generation (MWh)*CM Emission factor (tCO2e/MWh) – monthly project activity emissions (tCO2e)

The CM Emission factor is **0.555** in tCO2e/MWh, which is the baseline emission factor for the project (calculated *ex ante*) that will be used for the first crediting period (7 years). No rounding needs to be made per month when calculating monthly ERs, as this is only done to measure progress. At the end of the year, the ERCP manager should sum the resulting monthly ERs of the project to obtain the yearly project ERs ready for verification. Resulting yearly ERs must be rounded down to the nearest integer. Once the yearly ERs calculation is completed in the Nasulo ERs at January.xls (January is the last month of the year, for the MP), this file should become Nasulo ERs at "yearly period in question".xls.

The ERCP Quality Control and Organizational Structure can be seen in the annex section of this MP.

III. Sustainable Development Monitoring Plan ("SDMP"):

Being a CDM activity, the project must meet the requirements of The Kyoto Protocol Article 12 for CDM Projects, which states that the CDM activity must assist the host country in achieving sustainable development. The Government of Philippines has endorsed the project as a CDM-eligible activity. This part of the MP explains why it can be taken for granted that the project will contribute to environmental sustainability as well as development in the Philippines over its lifetime. The sustainable development objective applies also to projects, where not only positive but also negative environmental and social effects are conceivable. The MP for the project specifies sustainable development indicators and targets, which must be monitored and met by the operator and the area to which these indicators and targets will be applied.

*The SDMP can be seen in the annex section of this MP***.**

A. Environmental Sustainability: Impact on Local Pollution

In addition to mitigate emission of CO2, the project will reduce emissions of local pollutants (particularly SO_2, NOx and particulates).

Since the project is basically an optimization of the existing geothermal production field, the scale of activities and new processes involved is expected to be small compared to a full blown geothermal power development. Only minimal incremental environmental impacts are anticipated. The environmentally critical activities are: land clearing and civil works involved in the preparation of the 1-ha power plant site, the 0.5-km access road and the 1.0-ha new re-injection well pad; the repair/drilling of old/new wells; and the operation of the 20MW additional generating capacity. The likely environmental issues include: increased sedimentation from the civil work activities; the handling and disposal of wastes, which include drilling wastes, spent geothermal fluids or brine, cooling tower blow down and sludge; and, the air quality impact of the additional air emissions from the new plant, particularly hydrogen sulphide. The EA provided very comprehensive assessments of the environmental impacts (e.g., geology, hydrology, water quality, aquatic and terrestrial ecology, air quality and socioeconomics). It has identified and addressed both minor actual impacts as well as low probability potential impacts. The following are assessments of the critical environmental issues:

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Natural Habitat and Protected Areas- The associated infrastructure and civil works activities are not expected to affect critical natural habitats. The 4.1 hectares of land to be opened up is a logged-over or fallowed area. Project documents provided also indicate that the project site does not fall within a protected area. The nearest protected area is the Balinsasayao Twin Lakes which is roughly 3 km from the site.

B. Socio-Economic Sustainability

Community Acceptance – The project is received well by the local communities as it is viewed as an addition to the existing geothermal operations which is providing them benefits. The key stakeholders of the project are the National Government of the Philippines, the host Local Government Units and residents of Barangay Puhagan, Municipality of Valencia and Province of Negros Oriental. The local governments and residents will benefit from increased royalty receipts and other law-mandated funds from the project. At present, local residents are already benefiting from the royalties and other law-mandated funds from existing Palinpinon I and II projects in the form of subsidized power rates (up to 100% of monthly household consumptions in host barangays), livelihood support, environmental, health and other social development interventions.

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IV. Annexes

Sustainable Development Monitoring Plan ("SDMP")

The SDMP will cover the project's area of influence and their habitants. The following sustainable development indicators and targets framework will facilitate the measurement of progress towards sustainability. The indicators will be measured by the project sponsor and revised annually[25] by the verifier to check compliance with targets. The targets will be progresses[26] registered by the indicators. The following indicators have been established:

Potential Adverse Impact	Description	Management Measures/Action	Verifiable Indicator	Schedule
A. Civil Works (Vegetation Clearing, Excavation, Slope Cutting)				
Conversion of a total of 2-ha shrubland/fallowed swidden farms into a new well pad and access road; removal of some tree stands.	The tree inventory counted a total of 29 trees.	• Secure a Special Land Use Permit (SLUP) and Tree Cutting Permit from DENR (Department of Environment and Natural Resources) • Replacement reforestation elsewhere within the area through contract reforestation with existing Farmer' Association. • Implementation of the Watershed Management Plan as contained in the EA Report.	SLUP; Tree Cutting Permit; New reforestation project; and Livelihood project.	Before the start of construction
Soil erosion and possible sedimentation of water channels	Sediments will mostly come from the opening of 500-m access road and 1.0-ha reinjection wellpad.	• Slope stabilization through mechanical (i.e., wattling, riprapping) and biological (i.e. seeding or revegetation of exposed slopes with fast growing cover crops) • Sediment/erosion control measures such as checkdams, ripraps, gabions, silt traps and drainage canals. • Proper disposal of earth spoils; Cut-and-fill method and hauling/disposal of excess earth to the designated spoil disposal area.	Presence of stabilized slopes erosion control measures and, Spoil Disposal Area.	During construction roads and wellpads
Possible increase in migrant worker population	This impact is not expected to be significant as the area was previously host to bigger Pal I and Pal II projects.	• Adoption of a local hiring policy • Coordination with local government officials and contractors on local hiring policy	Local hiring policy document; Number of locally hired workers.	During construction
Possible increase of settlements and encroachments in newly opened up areas	The 500-m new access road may attract new informal settlers and swidden farmers.	• Coordination with local government officials in the implementation and enforcement of forestry laws	MOA with local government units (LGU) or other evidences of coordination with	During and after construction

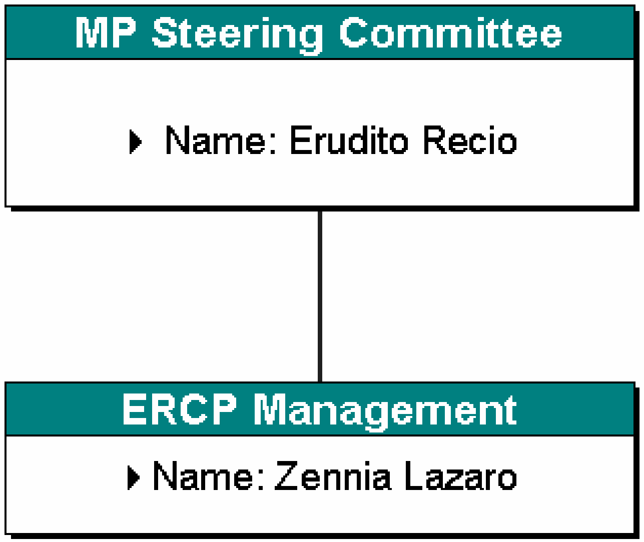
[25] The year for the MP runs from February to January.
[26] Progresses meaning positive results of the indicators.

Potential Adverse Impact	Description	Management Measures/Action	Verifiable Indicator	Schedule
		• Continued implementation of forest patrols with the involvement of local communities	LGU and local communities on forest protection.	
B. Well Drilling and Testing				
Deterioration of air quality due to release of Hydrogen Sulphide	Vertical well testing is 30 minutes long while horizontal well testing will last for about 3 months.	• Ducting of non-condensable gas (NCG) to improve air dispersion	NCG ducts installed; Levels of hydrogen sulphide	During well drilling and testing
Possible temporary, localized defoliation of vegetation around the production well pad area due to release of hot steam during well testing	The production wellpad where well testing will occur is already a developed area.	• Proper positioning of silencer during 90-day horizontal discharge away from critical areas	Silencer properly positioned; Absence of damage/defoliation of surrounding vegetation.	During well drilling and testing
Possible migration of faunal species due to increase in noise level at the wellpad	Any disturbance will be felt only within the existing production wellpad which is located in a relatively developed area.	• Limit duration of vertical testing to 30 minutes. • Installation of silencer and/or rock mufflers during horizontal testing.	Silencer and rock mufflers installed.	During well drilling and testing
Possible contamination of surface water from liquid wastes (i.e. geothermal brine and drilling wastes).	The existing production wellpad is equipped with sumps to temporarily contain drilling wastes and geothermal brine during testing. The new reinjection wellpad will also be provided with sumps.	• Use of sumps with impervious linings. • Provision of storm drainage, oil traps, ring drains and levees.	Sumps with impervious linings, adequate drainage and oil traps are provided at wellpads; Water quality monitoring report.	During well drilling and testing
C. Steam Generation, Power Plant Operation, Transmission				
Possible contamination of water channels from liquid wastes (i.e., geothermal brine and cooling tower blowdown)	The project will adopt a zero discharge system (ZDS) where liquid wastes will be reinjected. The handling of project's liquid wastes will be integrated into the existing Pal II ZDS.	• In case of ZDS failure, regulated discharge and continuous water quality monitoring should be done to ensure that receiving water channels will remain within water quality standards.	Incident reports; Water quality monitoring report and DENR report.	During ZDS failure
Possible contamination of environment and groundwater from cooling tower sludge	Sludge handling system already in place for Pal I and II. The amount of sludge to be generated by the project is only 1 drum per year.	• Cement fixing of cooling tower sludge before entombment into the cellar pit.	Sludge cellar pit installed.	After every PMS
Possible deterioration of air quality due to the release of Hydrogen Sulphide	The air dispersion study indicates that the ambient H2S standard will not be exceeded, given background	• Management of geothermal airshed such that ambient standard is not exceeded. • Regular ambient H2S monitoring	Air quality monitoring report to DENR; NCG ducting installed at cooling towers	Operations Phase

Potential Adverse Impact	Description	Management Measures/Action	Verifiable Indicator	Schedule
	levels and stack height.	• Ducting of non-condensable gas at cooling towers to improve dispersion		
Sudden decrease in employment and livelihood opportunities as construction activities stops.	There are existing associations of local residents organized under the company's Corporate Social Responsibility (CSR) program that receives livelihood support.	• Provide livelihood support through existing cooperatives and associations • Phase in new livelihood through local government using DOE funds and royalty	Livelihood projects of farmers' associations (FAs); Evidence of PNOC-EDC and DOE funds support to FAs.	Operations phase

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

ERCP Organizational Structure



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

ERCP Quality Control

Gathering of Project Electricity Generation Data

Data & Source

- The Project monthly generation that is registered by TRANSCO (or the market operator when it is finally established)

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 TRANSCO
- To whom does it comes? Zennia Lazaro

Quality of Data Processing

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

}

- Monthly calculation involves 5 steps
- All of it must be done in excel and documented with receipt of sales
- Yearly consolidation of monthly calculation

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

ERCP Quality Control

Calculation of Project Emissions

The project emissions that will have to be monitored (on a monthly basis) are the following:

- **Fugitive emissions of CO2 and CH4 due to release of non-condensable gases from produced steam**

*PES = (Wmain,CO2+Wmain,CH4*GWPCH4)*Ms*

Where: *Wmain,CO2* and *Wmain,CH4* are the average mass fractions of carbon dioxide and methane in the produced steam
GWPCH4 is the global warming potential of methane
Ms is the quantity of steam produced

- **Carbon dioxide emissions resulting from combustion of fossil fuels related to the operation of the plant**

$$PEFF_y = \sum_i F_{i,y} \cdot COEF_i$$

Where: *Fi* is the fuel consumption of fuel type i
COEFi is the CO2 emission factor coefficient of the fuel type i

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Note 1: Flow Rates
Steam flow rate, power plant.
The steam quantity discharged from the geothermal wells should be measured with a venture flow meter (or other equipment with at least the same accuracy). Measurement of temperature and pressure upstream of the venture meter is required to define the steam properties. The calculation of steam quantities should be conducted on a continuous basis and should be based on international standards. The measurement results should be summarized transparently in regular production reports.

Note 2: Non-condensable gases (NCG) in geothermal steam
NCG sampling should be carried out in production wells and at the steam field-power plant interface using ASTM Standard Practice E1675 for Sampling 2-Phase Geothermal Fluid for Purposes of Chemical Analysis (as applicable to sampling single phase steam only). The CO2 and CH4 sampling and analysis procedure consists of collecting NCG samples from the main steam line with glass flasks, filled with sodium hydroxide solution and additional chemicals to prevent oxidation. Hydrogen sulphide (H2S) and carbon dioxide (CO2) dissolve in the solvent while the residual compounds remain in their gaseous phase. The gas portion is then analyzed using gas chromatography to determine the content of the residuals including CH4. All alkanes concentrations are reported in terms of methane. The NCG sampling and analysis should be performed at least every three months and more frequently, if necessary.
For this Monitoring Plan we consider that sampling and analysis will be done monthly.

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

ERCP Quality Control

Calculation of ERs

In order to calculate the project monthly ERs, the following formula has to be used:

ERs (tCO2e) = Baseline Emissions (tCO2e) – Project Emissions (tCO2e) = Project Electricity Generation (MWh) x 0.555 (tCO2e/MWh) – Project Emissions (tCO2e)

Note: 0.555 tCO2/MWh is the baseline emission factor that will be used for the first crediting period (7 years). It has been calculated Ex-Ante.

Data Storage and Delivery

Quality of Data Storage	▪ Prevent Excel versioning problem, by keeping "a new" Excel software package every year in PCs used for the ERs calculations ▪ Keep all data for 2 years after the first crediting period (9 years) – assign a password to excel spreadsheets used for the ERCP ▪ Save the document with the last date in which an alteration was made, so that old versions are kept in disk ▪ Keep all written documentation in a folder that will be provided to the verifier together with the data in excel collected
Quality of Data Delivery	▪ Provide to the Verifier e-mails /CD through which TRANSCO delivered the original project electricity generation data ▪ Provide to the Verifier receipt of sales ▪ Provide to the Verifier all calculations made (project emissions and project ERs) by showing all preliminary versions of spreadsheets saved in disk

Annex 5

ABBREVIATIONS

AERMOD	Air Dispersion Modelling System
BM	Build Margin
BOT	Build Operate and Transfer
CAPM	Capital Asset Pricing Model
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CRP	Country Risk Premium
CSR	Corporate Social Responsibility
DENR	Department of Environment and Natural Resources
EA	Environmental Assessment
EPIRA	Electric Power Industry Reform Act
ER	Emission Reduction
ERCP	Emission Reduction Calculation Procedure
FA	Farmers Association
FCRS	Fluid Collection and Reinjection System
GHG	Greenhouse Gas
GWh	Gigawatt hour
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
IRR	Internal Rate of Return
LGU	Local Government Unit
MP	Monitoring Plan
MSMT	Multisectoral Monitoring Team
MW	Megawatt
NEC	Net Efficiency Conversion
NPC	National Power Corporation
O&M	Operation & Maintenance
ODA	Official Development Assistance
OM	Operating Margin
PDOE	Philippine Department of Energy
PNOC-EDC	Philippines National Oil Company Energy Development Corporation
PPA	Power Purchase Agreement
SLUP	Special Land Use Permit
SNGPF	Southern Negros Geothermal Production Field
TRANSCO	National Transmission Company

WESM	Wholesale Electricity Spot Market
ZDS	Zero Discharge Scheme