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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

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Bekasi Power CCPP project in Indonesia
Version 20
Date 02/11/2010

A.2. Description of the project activity:

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The project activity is an installation of a 125.9 MW_{el} combined cycle power plant (CCPP) connected to the grid and firing natural gas. The project activity is undertaken by PT Bekasi Power at Tanjung Sari village, Cikarang sub district, Bekasi, West Java, Indonesia.

The project technology consists of two Gas Turbine Generator (GTG) units each capacity of 37.97 MW_{el} (Site Rated). This will be combined with two Heat Recovery Steam Generators (HRSGs) and one Steam Turbine Generator (STG) unit of 50 MW_{el} rated capacity along with all electrical systems, controls and instrumentation.

The project will supplement the installed electricity generating capacity currently supplying to the grid, and displace the production of more carbon intensive generation. The produced electricity will be sold to the state-owned electricity company Perusahaan Listrik Negara or PLN. Electricity demand in Indonesia is growing rapidly and due to the availability of domestic coal the Indonesian government is placing an emphasis on coal based generation expansion. Under the “Crash programme” 24 new coal fired power plants units (PLTU) with a total capacity of 8,192 MW_{el} are planned and in Java alone 10 units of PLTU with a total capacity of 7,140 MW_{el} will be built. The current trend in Indonesia is clearly focused on the construction of coal power plants and the economically most attractive baseline scenario alternative for the project owners is also coal based generation.

PT. Perusahaan Gas Negara (Persero) Tbk. (PGN) and PT. Bayu Buana Gemilang (BBG) have agreed to supply the natural gas to the project activity. For detailed technical description of the project activity please refer to section A.4.3.

Contribution to sustainable development

Benefits for Local Economy:
The construction and operation of the power plant will directly create employment for the local skilled and semi-skilled population. About 150 people will be employed during the construction phase and 70 people during the operation phase.

Benefits to the environment:
The generation of power from natural gas will reduce the dependence on coal of existing and planned grid based electricity generation. This will have a positive impact not only through a reduction of greenhouse gas emissions but also through a reduction of other harmful emissions, like NO_X and SO_X as compared to the baseline.

A.3. Project participants:

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Name of Party involved ((host) indicates a host Party)	Private and/or public entity(ies) project participants (as applicable)	If Party wishes to be considered as a project participant
Indonesia (host)	PT Bekasi Power	No
United Kingdom	Agrinergy Pte Ltd	No

Contact details as listed in Annex I.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

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A.4.1.1. Host Party(ies):

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Indonesia

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

>>
West Java

A.4.1.3. City/Town/Community etc:

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Tanjung Sari village, Cikarang sub district, Bekasi District

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

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The geographical GPS coordinates of the project activity are:
Latitude: 06°16’16.33’’S
Longitude: 107°9’32.17’’E

Figure 1: Location map of Indonesia

The project activity is located in Tanjung Sari village, Cikarang sub district, Bekasi, West Java. It is 35km from Jakarta, 65km from Soekarno Hatta Airport and 56 km from Tanjung Priok.

Figure 2: Location map of West Java, Indonesia

Figure 3: Location map of project activity

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

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Category 1: Energy industries (renewable-/ non renewable sources)

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

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The project activity has two Gas Turbine Generator (GTG) units each with a capacity of 42.1 MW_{el} (ISO Rated). This will be combined with two Heat Recovery Steam Generators (HRSGs) and one Steam Turbine Generator (STG) unit of 50 MW_{el} rated capacity along with all electrical systems, controls and instrumentation.

Technical details of gas turbines (2 set)

Manufacturer : General Electric
Model : PG 6581 B
Fuel : Dual (Natural gas & Diesel oil)
Fuel pressure : 22 bar (g) (at inlet gas turbine)

	ISO Rated	**Site Rated**
Inlet air temperature, °C	15	32
Inlet air pressure, bar (g)	1	1
Design output, MW_{el}	42.1 (Apparent power output)	37.97 (Real power output)
Design heat rate, kJ/kWh	11,220	11,491
Design exhaust flow, kg/h	530,000	492,600
Exhaust temperature, °C	548	558.9

Power factor of generators	0.90

High temperature gas coming out of the turbines will be passed to two sets of Heat Recovery Steam Generators (HRSGs) to produce steam. The HRSGs are manufactured by Thermax Babcock & Wilcox and will deliver a Maximum Continuous Rating (MCR) of 86 tph. The HRSGs are dual pressure.

Technical details of HRSG

Input temperature	: 589.31°C
Outlet temperature	: 158°C
Steam quantity	: 78-86 tph (Control range per HRSG)
Steam pressure	: 92 kg/cm^2
Steam temperature	: 535°C
Supplementary firing	: 0.95MMSCFD

Technical details of steam turbine

Manufacture's model	: C11-R16-X
Generation capacity	: 50 MW$_{el}$
Steam pressure	: 88 kg/cm^2
Steam temperature	: 530°C
Steam quantity	: 165.8 tph

The steam turbine is a single shaft, single cylinder condensing type turbine.

Other auxiliary systems including a water cooling treatment and disposal plant, chemical system compressed air system, lifting equipment, main station fire fighting system, ventilation and air conditioning will also be installed.

Fuel Supply

PT. Perusahaan Gas Negara (Persero) Tbk. (PGN) and PT. Bayu Buana Gemilang (BBG) have agreed to supply a minimum of 0.5 million MMBTU per month of natural gas to PT Bekasi Power. The pressure of gas supplied by PGN and BBG is approximately 8-15 bars[1] - it will be necessary to install a compressor to raise the pressure to 20-22 bars to ensure it matches the pressure required by the gas turbine.

Small amounts of High Speed Diesel (HSD) will be fired to start-up the turbines, and in case of disruption to gas supply a blackout diesel generator has been installed to provide backup electricity to the control room.

The quantity of HSD combusted in the project activity during the year 'y' will be monitored. As per the applicability of AM0029: "*Natural Gas should be the primary fuel. Small amounts of other start-up or auxiliary fuels can be used, but can comprise no more than 1% of total fuel use, on energy basis*".
For detailed monitoring plan of the project activity please refer to section B.7.

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[1] Source: Gas Purchase Agreements Bekasi Power - BBG (Page 3) and PGN (Page 2)

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

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A 10 year fixed crediting period has been chosen for the project activity.

Years	Annual estimation of emission reductions in tonnes of CO_2e
Sept 2010 - Dec 2010	109,148
2011	327,443
2012	327,443
2013	327,443
2014	327,443
2015	327,443
2016	327,443
2017	327,443
2018	327,443
2019	327,443
Jan 2020 - Aug 2020	218,296
Total estimated reductions (tonnes CO_2e)	3,274,430
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tonnes of CO_2e)	327,443

A.4.5. Public funding of the project activity:

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The project has not received any public funding.

SECTION B. Application of a baseline and monitoring methodology

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

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Approved baseline methodology AM0029 – Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas - Version 03

Version 05.2 - Tool for demonstration assessment and of additionality
Version 02.0 - Tool to calculate emission factor for an electricity system

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

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Applicability conditions	Project activity
The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant	This condition is satisfied as the project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant. PT Bekasi Power is finalising negotiations on an agreement for the sale of electricity to the state-owned company PLN (“Perusahaan Listrik Negara”). The CCPP is expected to operate at full capacity from April 2010.
The geographical/physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available	Yes, the geographical/physical boundaries of the baseline grid (JAMALI grid) are clearly identified. The data pertaining to the grid and for estimation of baseline emissions is publicly available.
Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity	Natural gas is sufficiently available in Indonesia. The state owned company “Perusahaan Gas Negara” (PGN) has a specific transmission pipeline from Grissik (Sumatera) to West Java (Jakarta, Bogor, Banten, Bekasi and Kerawang) called “Strategic Business Unit I” (SBU I). The gas is transported through two pipelines SSWJ I (530 mmscfd or 625,330.6 m^3/h) and SSWJ II (440 mmscfd or 519,142.36 m^3/h) with a total capacity of 970 mmscfd (1,144,472.9 m^3/h) for the area. In comparison, PT Bekasi power has a gas consumption of 11 mmscfd and the local distribution was 300 mmscfd in 2006, 402 mmscfd (474,307.29 m^3/h) in 2007 and 577 mmscfd (680,784.29 m^3/h) in 2008.[2]

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[2] Source: Perusahaan Gas Negara (PGN) Gas report. Dec 08

	Furthermore, in 2007, Indonesia had proven natural gas reserves of 3.18 trillion m^3, production of 67.6 billion m^3 and consumption 43.7 million m^3. Only 0.06% of the natural gas extracted is locally used and therefore natural gas is abundantly available for use in power production. Hence, implementation of the project activity does not divert natural gas that would have been used elsewhere. Additional clarification on Natural gas availability has been added, please refer to Annex 7.

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

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The spatial extent of the project boundary, as indicated below, includes the project site and all power plants connected physically to the baseline grid.

Power generation by project activity → **JAMALI grid (all power plants that are physically connected through transmission and distribution lines to the project activity and that can be dispatched without significant transmission constraints)**

Project Boundary

The greenhouse gases included in or excluded from the project boundary are shown in Table below.

	Source	Gas	Included?	Justification/Explanation
Baseline	Power generation in the baseline	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification. This is conservative.
		N_20	No	Excluded for simplification. This is conservative
Project activity	On-site fuel combustion due to the project activity	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification
		N_20	No	Excluded for simplification

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

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The baseline scenario is identified as per the guidance given in AM0029, Version 03.

Step 1: Identify plausible baseline scenarios

Alternatives to be analysed should include, *inter alia*:

1. The project activity not implemented as a CDM project;
2. Power generation using natural gas, but technologies other than the project activity;
3. Power generation technologies using energy sources other than natural gas;
4. Import of electricity from connected grids, including the possibility of new interconnections.

Table 1: Baseline scenario assessment

Alternatives	**Plausibility/Eligibility**
1. The project activity not implemented as a CDM project	
Natural Gas CCGT without CDM	Plausible. This is a plausible alternative that can deliver similar services to the proposed project activity. Meets all eligibility conditions. However, Section B.5. of the PDD will demonstrate that this option faces financial barriers to its implementation and hence cannot be a baseline scenario.
2. Power generation using natural gas, but technologies other than the project activity	
Natural Gas Open Cycle Gas Turbine	Not plausible. An open cycle gas turbine has a relatively lower thermal efficiency and is now rarely implemented. Alternative (2) is not a plausible baseline scenario alternative.
3. Power generation technologies using energy sources other than natural gas	
(a) Coal-fired power plant	Plausible. Power generation in Indonesia is dominated by coal-based power plants for both base and peak load and therefore (a) represents a plausible baseline scenario. A typical 2x65 MW_{el} coal based power plant can provide services similar to the proposed project activity and is a credible alternative. A larger coal power plant is also a realistic and plausible alternative. However the generation costs of a larger unit would be lower due to economies of scale and therefore selection of a 2x65 MW_{el} plant is reasonable and conservative.
(b) Oil-fired power plant	Plausible. Whilst at the time of the project decision, oil prices were high and the Indonesian government is trying to reduce its dependence on oil, Option (b) is considered a plausible baseline scenario. A typical 2x65 MW_{el} oil based power plant can provide services similar to the proposed project activity and is a credible alternative.
(c) Nuclear power plant and	Not plausible. Indonesia is yet to commission its first nuclear power plant.
(d) Hydro power plant	Not plausible. Based on *Financial Challenge in Increasing*

	Hydropower Use in Indonesia - by Rachmawan Budiarto from June 2009[3], hydro power plants are characterized by low operational costs but high investment costs. Moreover, electricity unit costs depend greatly on annual production hours (availability factor), which differ due to especially variation of local hydrological and meteorological conditions (temperature and precipitation in the catchment area). Revenue from generated electricity sales is usually the only source of servicing the investment debt. The report *Obstacles and Contractual problems during the construction of HPP* by Sarwono Hardjomuljadi from June 2009[4] states that ‘’hydropower plant project consists of very complex structures and involves a huge amount of initial cost a quite long construction period’’. Therefore, the hydro power plant option has not been considered plausible option.
(e) Wind power plant	Not plausible. Based on ASEAN green IPP network[5], wind power development has been very slow due to technical and financial considerations. In Indonesia, it is limited to stand-alone electricity production in rural and remote areas. So far, no grid-connected medium or large-scale wind power plants have been installed in Indonesia.
(f) Biomass power plant	Not Plausible. Not a realistic and credible alternative. Currently there are no comparable biomass based power plants constructed recently in Indonesia.
(g) Geothermal power plant	Not Plausible. Not a realistic and credible alternative. Higher investment cost - Geothermal power plants are characterized by high capital investment for exploration, drilling wells, and plant installation, but low cost of operation and maintenance. In 2001, EPRI[6] estimated that capital reimbursement and associated interest account for 65% of the total cost of geothermal power. Capital costs of a combined cycle natural gas power plant, in contrast, only represents about 22% of the levelized cost of electricity produced from the plant.[7] Exploration cost and Drilling cost - Financing the exploration details for geothermal small-scale development (< 10 MW_{el}) in

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[3] Source: Financial Challenge in Increasing Hydropower Use in Indonesia - by Rachmawan Budiarto - June 09

[4] Source: Contractual problems during the construction of HPP - by Sarwono Hardjomuljadi - June 09

[5] http://www.ec-asean-greenippnetwork.net/dsp_page.cfm?view=page&select=97

[6] Source: G. Simons, "California Renewable Technology Market and Benefits Assessment", EPRI, 2001.

[7] Source: http://www.geo-energy.org/aboutGE/powerPlantCost.asp

	the Indonesia east region that is considered less attractive for investors.[8] Escrow account - Both the regular tender and the direct tender participants are required to submit a significant amount of bid bond that is enclosed in the application document, in the range of fifty percent (50%) of signature bonus fee. The successful bidder or the winner shall submit full amount (100%) of the signature bonus to the prime bank in Indonesia. If the successful bidder or the Winner fails to fulfil this obligation as contemplated in the application agreement, the tender committee can automatically terminate without prior or further notice, and the Winner place is downgraded to the second place.
4. Import of electricity from connected grids, including the possibility of new interconnections.	
Import from neighbouring power grids	Not plausible. The Sumatra, Kalimantan, and Sulawesi grids are not connected to the JAMALI grid.

From the above baseline scenario assessment analysis scenario 1, scenario 3(a) and scenario 3(b) are considered plausible alternatives to the project activity. These scenarios include all realistic and credible alternatives that deliver similar services to the project activity. In line with AM0029 version 3 they are not necessarily available to project participants but rather represent the likely sources of generation and capacity expansion in the absence of the project activity.

Step 2: Identify the economically most attractive baseline scenario alternative
Investment analysis is used to identify the most attractive baseline scenario. Levelised Cost of Electricity Generation (LECG) is the most suitable and transparent financial indicator to evaluate the baseline scenario alternatives. Generation expansion in the absence of the CDM and any domestic E- policies will follow the least cost path and therefore the baseline scenario alternative with the lowest LECG is the most likely.

Table 2: Fuel price comparison per unit of energy

Fuel Type	**Fuel price**		**Energy in Joule**		**Price of fuel**	**Emission Factor**
					Cts USD/ TJ	KgCO2/TJ
Natural Gas	5.3	USD/mmBTU[9]	1,055	J/BTU	5.59	64,200
Coal	54	USD/tonne[10]	25.8	TJ/tonne	2.1	96,100
Oil	0.56	USD/liter[11]	36,1	GJ/kliter	20.21	74,100

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[8] Source: Geothermal electricity bidding Principle - *Riki F. Ibrahim, Endro U. Notodisuryo, Puguh Sugiharto - Indonesia Renewable Energy Society)*

[9] Source: Gas purchase agreements, PGN price: 5.639 USD/MMBTU from (50%) + BBG price: 5.589 USD/MMBTU (50%) + 0.2 for gas compression

[10] Source: Jakarta Stock Exchange, 30/05/2007 (KOB Kalimantan 5900 kcal/kg - 46 USD/tonne FOB (free on board) + 8 USD/tonne (transport to Java)

[11] Source: Pertamina fuel price apr 2007

Coal has a lower cost of energy compared to natural gas, as well as a higher emission factor.

The basic levelised cost of electricity generation methodology used in this PDD is based on ‘Projected Costs of Generation Electricity: 2005 update’ published by the International Energy Agency (IEA)[12]. The formula applied to calculate the levelised electricity generation cost (LEGC) is the following:

$$EGC = \frac{\sum_t [(It + Mt + Ft)(1+r)^{-t}]}{\sum_t [Et(1+r)^{-t}]}$$

Where:

EGC	Average lifetime levelised electricity generation cost per kWh
It	Capital expenditure in the year t
Mt	Operation and maintenance expenditures in the year t
Ft	Fuel expenditure in the year t
Et	Electricity generation in the year t
r	Discount rate
n	Lifetime of the System

Summary of data input for LECG calculation

Table 3: Specific data for CCPP (advance class gas turbine)

Assumptions	S1.	Value	Units	Source
Capacity of the plant		125.9	MWel	Feasibility study
Capital expenditure (initial)	It	130,644,000	USD	EPC contract
O&M in the year t	Mt	0.412	USD/kWh	Feasibility Study - Chapiter IX
Fuel expenditure	Ft	Fp*Fq	USD	
Fuel quantity	Fq	7,230,013	MMBTU	Calculated
Fuel price	Fp	5.3	USD/MMBTU	Feasibility Study - Chapiter IX + Compression
Fuel escalation		2.5	%	Feasibility study Chapiter IX
Electricity generation in the year t (Net)	Et	891,070	MWh	Calculated
Discount rate	r	10	%	Feasibility study Chapiter IX
Lifetime of the System	n	25	Years	GE email
Electricity Generation Cost	**EGC**	**7.08**	cents USD/kWh	Calculated[13]

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[12] Source: http://www.iea.org/Textbase/publications/free_new_Desc.asp?PUBS_ID=1472, Annex 5

[13] Source: Levelised Electricity Generation Cost calculation is performed in the supporting doc “financial analysis” excel spreadsheet

Table 4: Specific data for coal based power plant

Assumptions	S1.	Value	Units	Source*
Capacity of the plant		2 x 65	MWel	NA
Capital expenditure (initial)	*It*	153,624,000	USD	PT PLN Persero
O&M in the year t	*Mt*	0.400	USD/kWh	
Fuel expenditure	*Ft*	Fp x Fq	USD	
Fuel quantity	Fq	388,724	tonnes	Calculated[14]
Fuel price	Fp	54	USD/tonne	Jakarta Stock Exchange, 30 May 2007
Fuel escalation		1.5	%	
Net Electricity generation in the year t	*Et*	891,070	MWh	NA
Discount rate	*r*	10	%	
Lifetime of the System	*n*	25	years	
Electricity Generation Cost	**EGC**	**4.75**	cents USD/kWh	Calculated

* Additional clarification on input values has been added, please refer to Annex 8.

Table 5: Specific data for oil based power plant

Assumptions	S1.	Value	Units	Source*
Capacity of the plant		2 x 65	MWel	NA
Capital expenditure (initial)	*It*	146,721,680	USD	PT Wijaya Karya Tbk
O&M in the year t	*Mt*	0.320	USD/kWh	PT PLN Persero
Fuel expenditure	*Ft*	Fp x Fq	USD	
Fuel quantity	Fq	277,229,126	tonnes	DIJPE data on GEF
Fuel price	Fp	0.559	USD/liter	Pertamina fuel price apr 2007
Fuel escalation		1.5	%	
Electricity generation in the year t (Net)	*Et*	891,070	MWh	NA
Discount rate	*r*	10	%	
Lifetime of the System	*n*	25	years	
Electricity Generation Cost	**EGC**	**21.65**	cents USD/kWh	Calculated

***** Additional clarification on input values has been added, please refer to Annex 8.

Table 6: Levelized costs of generation

Alternatives	**Generation cost of electricity[15]**	
	cents USD/kWh	IDR/kWh
Natural Gas	7.08	649.9

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[14] Source: Based on Bekasi - GHG_JAWABALI_2006_DJLPE-FINAL.xls

[15] Source; Based on the conversion rate at time of the decision (9174.31IDR/USD)

Coal	4.75	435.7
Oil	21.65	1986.0

From the above assessment, it is clear that the project activity has a lower financial indicator (higher cost of generation) compared to coal.

Sensitivity analysis

A sensitivity analysis has been performed in accordance with paragraph 16 and 17 of Annex 13, EB39 to confirm the conclusion regarding the financial indicator. The financial indicators are calculated for a variation of the following critical parameters:

- Plant load factor
- Cost of fuel

The sensitivity analysis was conducted for scenarios with variations in each and both of the above factors to assess

Table 7: Sensitivity analysis for each option (in cents USD/kWh)

Plant Load Factor	**-10%**	**-5%**	**0%**	**5%**	**10%**
Project activity not implemented as a CDM project, i.e. 125.9 MWel gas based combined cycle power plant with advance class gas turbine.	7.3	7.2	7.1	7.0	6.9
2 x 65 MWel coal fired pit head based power plant using conventional technology	5.0	4.9	4.7	4.7	4.6
2 x 65 MWel oil fired pit head based power plant using conventional technology	21.9	21.7	21.6	21.6	21.5
Fuel Price	**-10%**	**-5%**	**0%**	**5%**	**10%**
Project activity not implemented as a CDM project, i.e. 125.9 MWel gas based combined cycle power plant with advance class gas turbine.	6.6	6.8	7.1	7.4	7.6
2 x 65 MWel coal fired pit head based power plant using conventional technology	4.5	4.6	4.7	4.9	5.0
2 x 65 MWel oil fired pit head based power plant using conventional technology	19.7	20.7	21.6	22.6	23.6

The results of the sensitivity analysis conducted confirm that the cost of power generation using coal is the cheapest option and this is considered as the most economically attractive baseline scenario.

Figure 1: Variation of levelised cost with plant load factor

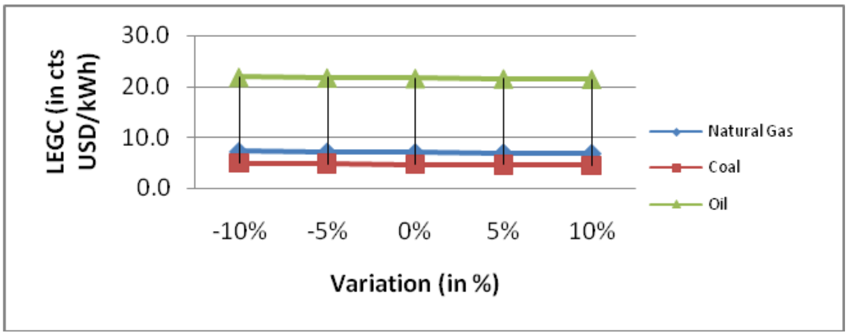
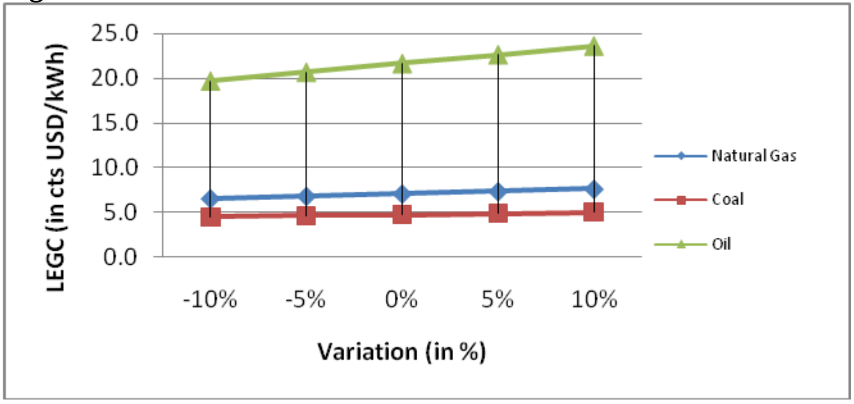


Figure 2: Variation of levelised cost with fuel cost



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

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As recommended in AM0029 v3, the project proponent is required to establish that the GHG reductions arising from the projects activity are additional to those that would have occurred in absence of the project activity as per the latest version of the *Tool for the demonstration and assessment of additionality*.

Since 2006, PT Bekasi Power was aware of the benefits of the CDM, internal documents dating back to October 2006 discuss the importance of CDM revenues to this project. PT Bekasi Power hosted and participated in a CDM seminar in Jababeka on 8 March 2007. Based on the CDM incentive, PT Bekasi Power decided to proceed with the project activity as a CDM project and this was notified in the following board meeting (12 March 2007) as well as in the earliest feasibility study (April 2007). The board of directors approved the investment and concluded an engineering, procurement & construction contract (Start date) later on 9 July 2007. Regular correspondences occurred between PT Bekasi Power and CDM consultants between the board meeting and the current CDM contract agreement signature.

In order to demonstrate that the project activity is not the baseline scenario, the methodology provides a set of steps. For AM0029, the following steps are required:

Step 1: Benchmark Investment Analysis. This step consists of the additionality tool step 2, sub-step 2b (Option III: Apply benchmark analysis); sub-step 2c (Calculation and comparison of financial indicators)

and sub-step 2d (Sensitivity analysis)
Step 2: Common practice analysis. This step consists of step 4 of the additionality tool
Step 3: Impact of CDM registration.

Step 1: Benchmark Investment Analysis
As per AM0029 (Version 03) and the *Guidance on the assessment of investment analysis* version 03 of EB 51 Annex 58, this step is applied to demonstrate that the proposed CDM project activity is unlikely to be financially attractive by applying sub-step 2b (Option III: Apply Benchmark Analysis), sub-step 2c (Calculation and comparison of financial Indicators), and sub-step 2d (Sensitivity Analysis) of the *Tool for the demonstration and assessment of additionality* - version 05.2, approved by EB39.

Sub-step 2b: Option III – Application of benchmark analysis
The project internal rate of return or project IRR is the most suitable financial indicator. The relevant benchmark for this indicator is the Investment Rate published by the Indonesian central bank (Bank Indonesia). The average investment Rate during 2006 was 15.44%. Please refer to Annex 6 for benchmark calculation data.

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

The table below summarise the key data used in the calculation of the project IRR

Assumptions	**Value**	**Units**	**Source**
Capacity of the plant	125.9	MWel	Feasibility study
Net electricity production	891,070	MWh/year	Calculated
Plant Load Factor	85	%	Feasibility study – Chap IX (+5% conservative load factor)[16]
Lifetime of the System	25	years	Technology provider letter (GE)
Capital expenditure (initial)	130,644,000	USD	EPC contract (Feasibility Study)
O&M in the year t	0.412	USD/kWh	Feasibility study – Chap IX
Natural Gas quantity	7,230,013	MMBTU	Calculated
Natural Gas price escalation	2.5	%	Feasibility study – Chap IX
Discount rate	10	%	Feasibility study – Chap IX
Natural Gas price	5.3	USD/MMBTU	Feasibility Study - Chapiter IX + Compression
Income tax	30	%	Gvt of Indonesia
CER price	20.3	USD	www.ecx.eu

The project IRR without CER revenues is 11.13%. This is below the 15.44% benchmark and the project activity is not considered a financially attractive investment. The full financial analysis spreadsheet is attached.

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[16] The PLF is in line with and indeed more conservative than the requirements of Annex 11 to EB48 GUIDELINES FOR THE REPORTING AND VALIDATION OF PLANT LOAD FACTORS

Sub-step 2d: Sensitivity analysis

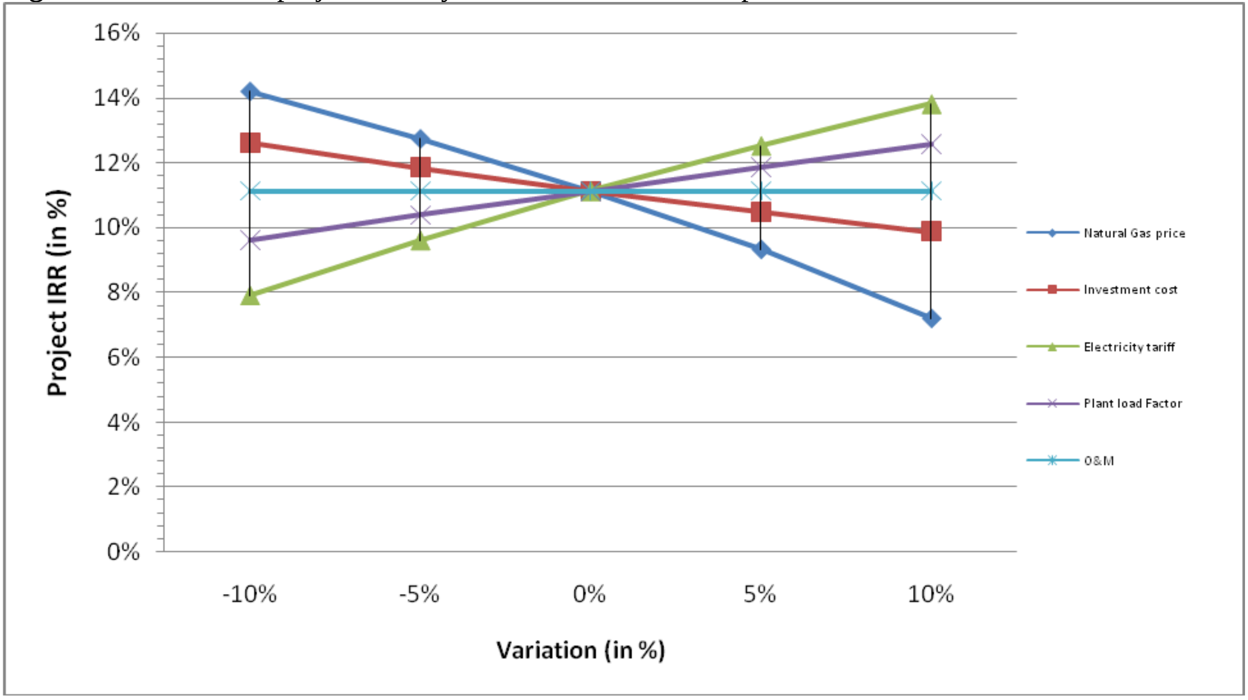
A sensitivity analysis has also been conducted to test the robustness of the conclusions drawn. The following parameters are critical assumptions in the project return and are subjected to variation in the sensitivity analysis:

- Natural gas price
- Investment cost
- Electricity tariff
- Plant load Factor
- Operational cost

The table below summarise the results of the sensitivity analysis:

Parameter	-10%	-5%	0%	+5%	+10%
Natural Gas price	14.20%	12.74%	11.13%	9.33%	7.20%
Investment cost	12.62%	11.85%	11.13%	10.48%	9.87%
Electricity tariff	7.91%	9.61%	11.13%	12.53%	13.82%
Plant load Factor	9.62%	10.39%	11.13%	11.87%	12.58%
O&M	11.13%	11.13%	11.13%	11.13%	11.13%

Figure 1: Variation of project activity IRR with critical assumptions



The results of the sensitivity analysis conducted confirm that the project IRR remains below the benchmark when key parameters are subject to variation.

Step 4: Common practice analysis

As outlined in AM0029 v3, the project proponent is required to establish that the project activity is not common practice in the relevant country and sector, by applying step 4 (Common practice analysis) of the latest version of the *Tool for the demonstration and assessment of additionality*.

Sub-step 4a: Analyze other activities similar to the proposed project activity:
The Indonesian power system is divided into seven[17] interconnected regional grids, namely Sumatra, Java-Madura-Bali (JAMALI), Kalimantan (3 grids) and Sulawesi (2 grids), plus more than 600 isolated systems. The JAMALI interconnected system is the largest (77% of power consumption) in the country, and the power generating capacity of this system totals 22,296 MWel[18].

The common practice analysis is restricted to CCGT plants operating, and located in the JAMALI grid.

Table 8: Natural gas based power plants developed in the JAMALI grid

Power Plant	**Location**	**Operation Year**	**Capacity (MWel)**	**Type of Fuel**	**Project owner**
Cilegon	Cilegon, Banten	2006	740	Gas & HSD Oil	PT PLN (Persero)
Muara Tawar	Bekasi, West Java	1995	2035	Gas & HSD Oil	PT PLN (Persero)
Tanjung Priok	Jakarta Raya	1993-1994	2 x 590	Gas & HSD Oil	PT Indonesia Power
Tambak Lorok	Semarang	1993	2x 530	Gas & HSD Oil	PT PLN (Persero)
Cikarang	Cikarang, Bekasi	1993	150	Gas & diesel	PT. Cikarang Listrindo
Gresik	East Java	1990	2260	Gas & diesel	PT PLN (Persero)
Grati	Pasuruan, East Java	1964	2 x 462	Gas & HSD Oil	PT Indonesia Power

Sub-step 4b: Discuss any similar Options that are occurring:
Indonesia is facing a crisis in electric power supply, as demand is growing by 8% a year as against production growth of only 3% per year. For the most recent 11 years, the share of newly built similar power plants (public and private) in the JAMALI grid accounted for less than 14% for gas-based plants, against over 86% for coal-based plants. Moreover, between 2002 and 2006 the share of electricity generated from gas based power plants in the JAMALI grid (public and private) decreased to 27%, whilst the share of generation accounted for by oil and coal increased by 41.3% and 34.5% respectively.
Indonesia is the second[19] largest exporter of coal in the world. In light of abundant availability of cheap coal and to reduce dependence on fuel oil, the Indonesian government has undertaken a "Crash Program". This program involves the construction of 24 new coal fired power plants units (PLTU) with a total capacity of 8,192 MWel. In Java, 10 units of PLTU with a total capacity of 7,140 MWel will be

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[17] http://www.senternovem.nl/mmfiles/Energy%20private%20sector%20in%20Indonesia_tcm24-288060.pdf

[18] Source: POWER GENERATING INDUSTRY IN INDONESIA - July 2008 - http://www.datacon.co.id/powergenerating.html

[19] Source: World Coal Institute – Coal facts2008 - http://www.worldcoal.org/assets_cm/files/PDF/coalfacts08.pdf

built (plants will have a capacity of 300 MWel to 660 MWel). The current trend in Indonesia is clearly focused on the construction of coal based power plants.

Mainly due to the government's plan to encourage coal based power projects it is likely that the share of power generation fired by natural gas will decline. Therefore, we consider that this evidence supports the fact that the project activity is not common practice in Indonesia.

Technology:
Out of the seven CCGT power plants mentioned above, six (Cilegon, Muara Tawar, Tanjung Priok, Tambak Lorok, Gresik, and Grati) are publicly owned by the Indonesian government. Those multi-fuel fired CCGTs have the flexibility to choose between a range of fuels, depending on economics and availability and are thus better able to diversify fuel risks and dispatch risks. The investment environment for public owned power plants is also different to that facing an IPP, and therefore these plants are not considered similar to the project activity.

The only similar CCGT plant (Cikarang) was built in 1993. In the case of Cikarang, it is should be considered this plant was constructed prior to the Asian economic crisis and during the time of the Suharto regime. Cikarang Listrindo was the first major private power project in Indonesia and the first to sell power back to the grid. The plant was owned by a relative of President Suharto[20]. In 1998, PLN cancelled the PPA with Cikarang Listrindo due to its price. Whilst the PPA price in the time of the decision to proceed with PT Cikarang Listrindo is not known, in 1996 it is reported to have been Rp 147.35 per kWh[21] or the equivalent of $0.063. If escalated as per the project activity tariff in the financial analysis for the project activity this would equate to approximately $0.07/kWh, which is a similar figure to that applied by the project activity. However the gas price paid by Cikarang Listrindo was much lower than that currently prevalent. Natural gas prices are correlated to oil prices and the oil price was some $19.10 per Barrel[22] in 1993 whilst at the time of the investment decision for the project activity it was approximately $68.5 per Barrel. Hard data on the gas price paid by Cikarang Listrindo is available for August 2006 and this gives a gas price of $2.45 per MMBTU[23] whilst the project activity must pay $5.6 per MMBTU – over double.

The above factors illustrate that the circumstances facing Cikarang Listrindo some 14 years prior to the project activity investment were distinct and unique. Specifically, the relationship between that plant and the then President Suharto allowed it a favourable gas price to electricity tariff spread far in excess of that facing the project activity. This allowed the plant to proceed without the benefit of CDM revenue.

Step 3: Impact of CDM registration
When the project activity is successfully approved and registered as a CDM project, the income from CERs sales will improve the financial attractiveness of the project activity. The IRR is increased to a level close to the required benchmark (although even with CDM revenue the benchmark is not crossed).

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[20] http://knowledge.wharton.upenn.edu/papers/1256.pdf - page 24

[21] Source: Bekasi - PT Cikarang Listrindo electricity tariff – High Beam Research - 29/06/1998.pdf

[22] Source EIA http://tonto.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WEPCMINAS&f=W

[23] Source: Bekasi - Invoice_Cikarang Listrindo – 18/09/2006.pdf

As validation takes place after start date we provide a chronology of events below:

Table 9: Chronology of events

S. No.	Activity	Date	Source
1	Internal memo on CDM	18/10/2006	Copy of internal memo
2	CDM seminar	08/03/2007	Copy of presentation
3	Board Meeting decision	12/03/2007	Copy of MoM
4	Feasibility Study	01/04/2007	Copy of FS
5	EPC contract	09/07/2007	Copy of contract agreement
6	CDM consultant discussion	02.08.2007	Copy of communications
7	CDM Contract Agreement with PT Agrinergy	20/02/2008	Copy of contract agreement
8	Stakeholder meeting	15/05/2008	Publication
9	EIA approval	19/05/2008	Copy of approval letter
10	Host Country LoA	21/01/2010	Copy of DNPI approval letter
11	Annexe 1 LoA	29/01/2010	Copy of DECC approval letter
12	COD[24]	01/04/2010	Project Owner Expectation

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

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In line with the methodology, the emission reductions are calculated as explained below.

$$ER_y = BE_y - PE_y - LE_y \qquad (1)$$

Where:

ER_y	Emissions reductions in year y (t CO_2e)
BE_y	Emissions in the baseline scenario in year y (tCO_2e)
PE_y	Emissions in the project scenario in year y (tCO_2e)
LE_y	Leakage in year y (t CO_2e)

Baseline emissions

Baseline emissions are calculated by multiplying the electricity generated in the project plant ($EG_{PJ,y}$) with a baseline CO_2 emission factor ($EF_{BL,CO2,y}$), as follows:

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y} \qquad (2)$$

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[24] At the time of the decision, PT Bekasi Power was expecting to operate the Turbine 1 (T1) in October 2009, the T2 and Steam Turbine (ST) in December 2009. Therefore, in accordance with the *Guidance on the assessment of investment analysis* version 03 of EB 51 Annex 58 – paragraph 6, input values used in all investment analysis has been assumed for this period (2009). However, due to delay in the project construction, the expected commissioning date has been delayed to April 2010 for T1, July 2010 for T2 and ST. In order to be consistent with the crediting period of the project activity, the Emission Reduction has been calculated as per the updated period (Sept 2010).

Where:

$EG_{PJ,y}$	Net electricity generated in the project activity during the year y, MWh
$EF_{BL,CO2,y}$	Baseline CO_2 emission factor, tCO_2/MWh

As per AM0029, to address the baseline uncertainties in a conservative manner, $EF_{BL,CO2,y}$ should be determined as the lowest emission factor among the following three options:

Option 1: The build margin, calculated according to *Tool to calculate emission factor for an electricity system*; and
Option 2: The combined margin, calculated according to *Tool to calculate emission factor for an electricity system*, using a 50/50 OM/BM weight.
Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above, and calculated as follows:

$$EF_{BL,CO2,y}\left(tCO_2 / MWh\right) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ / MWh \quad (3)$$

Where:

$COEF_{BL}$	Fuel emission coefficient (tCO_2e/GJ), based on Table 2.2 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories
η_{BL}	Energy efficiency of the technology, as estimated in the baseline scenario analysis above

According to AM0029, this determination will be made once at the validation stage based on an *ex ante* assessment and once again at the start of each subsequent crediting period (if applicable). If either option 1 (BM) or option 2 (CM) are selected, they will be estimated *ex post*, as described in *Tool to calculate emission factor for an electricity system.*

Option 1: Build Margin, calculated based on *Tool to calculate emission factor for an electricity system*

Build Margin emission factor

The build margin refers to a cohort of power units that reflect the type of power units whose construction would be affected by the proposed CDM project activity. The value of build margin emission factor is calculated based on the generation-weighted average emission factor (tCO_2/MWh) of representative power units during the 5 most recent years or the most recent 20% of the generating units built.

The build margin (BM) emission factor is 0.937 tCO_2/MWh[25] is obtained from BPPT (Agency for the Assessment and Application of Technology, Indonesia).

Option 2: The combined margin, calculated based on *Tool to calculate emission factor for an electricity system*, using a 50/50 OM/BM weight

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[25] Source: Bekasi - GHG_JAWABALI_2006_DJLPE-FINAL.xls

As per the *Tool to calculate emission factor for an electricity system*, the combined margin emission factor is calculated as combination of operating margin (OM) and build margin (BM) emission factors. According to AM0029, the weighting of OM and BM is 50/50.

$$EF_{CM,y} = w_{OM}.EF_{OM,y} + w_{BM}.EF_{BM,y} \qquad (4)$$

Where: $w_{OM} + w_{BM} = 1$

Operating Margin emission factor

The operating margin refers to a cohort of power plants that reflect the existing power plants whose electricity generation would be affected by the proposed CDM project activity.

The simple operating margin approach is not appropriate to calculate operating margin emission factor because the low-cost/must-run resources for the Jawa-Madura-Bali (JAMALI) grid constitute 61.4%[26] of the total grid generation in average of the five most recent years. Therefore, the average operating margin has been preferred.

The operating margin (OM) emission factor is 0.844 tCO_2/MWh[27] is obtained from BPPT (Agency for the Assessment and Application of Technology, Indonesia).

$$EF_{CM,y} = w_{OM}.EF_{OM,y} + w_{BM}.EF_{BM,y}$$

$$EF_{CM,y} = 0.5 * 0.844 + 0.5 * 0.937$$

Applying a 50/50 weight to the values for operating margin and build margin emission factors provided in the BPPT database, the Combined Margin emission factor calculated is 0.891 tCO_2/MWh[28].

Option 3: The emission factor of the technology identified as the most likely baseline scenario under "Identification of the baseline scenario"

As demonstrated under section B.4 earlier, coal fired power plant represents the technology that represents an economically attractive course of action and therefore coal fired power plant has been identified as the baseline scenario. The emission factor of the coal fired power plant is calculated using this equation as follows:

$$EF_{BL,CO2,y}\left(tCO_2 / MWh\right) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6 GJ / MWh$$

Based on the IPCC default value for coal emission coefficient ($COEF_{BL}$), the value used for the emission factor calculation is 0.0946 tCO_2/GJ[29]. And the value of the energy efficiency (η_{BL}) is 31.8%[30].

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[26] Source: Bekasi - GHG_JAWABALI_2006_DJLPE-FINAL.xls – GWh type fuel plant – Average ratio of LCMR (2002-06)

[27] Source: Bekasi - GHG_JAWABALI_2006_DJLPE-FINAL.xls

[28] Source for (CM) Combined Margin: http://dna-cdm.menlh.go.id/Downloads/Others/KomnasMPB_Grid_Sumatera_JAMALI_2008.pdf

[29] Source: IPCC Guidelines for National Greenhouse Gas Inventories, Table 2.2 (2006)

[30] Source: Refer to Annex 3 for the calculation of energy efficiency for coal technology

$$EF_{BL,CO2,y} = \frac{0.0946\,(\mathrm{tCO_2/GJ})}{31.8\%} * 3.6\ \ (GJ\,/\,MWh)$$

$$EF_{BL,CO2,y} = 1.070\ \mathrm{tCO_2e/MWh}$$

The result of the baseline emission factor for coal fired power plant is 1.070 tCO_2/MWh.

Baseline Emissions Factor
Emission factors determined using the three options are summarised in the table below

Table 10: Emission factors determined using the three options

Options	**Emission Factor (tCO2e/MWh)**
Option 1 : Build Margin for JAMALI Grid	0.937
Option 2 : Combined Margin for JAMALI Grid	0.891
Option 3 : Emission factor of coal based power plant	1.070

The lowest of all the three options for JAMALI Grid is Option 2 (Combined Margin) and hence this is the appropriate Baseline Emission Factor. Accordingly, the Baseline Emission Factor value applicable to the project activity is 0.891 tCO_2e/MWh.

As per AM0029, in case the Build Margin or the Combined Margin is selected as the Baseline Emission Factor, the Baseline Emission Factor (Combined Margin) will be determined ex-post, as described in *Tool to calculate emission factor for an electricity system.* In line with the ex-post determination of the baseline emission factor the Build Margin must be updated annually ex-post for the year in which the actual generation and associated emission reduction occur.

Project emissions
The project activity is on-site combustion of natural gas to generate electricity. The CO_2 emissions from electricity generation (PE_y) are calculated as follows:

$$PE_y = \sum FC_{f,y} \cdot COEF_{f,y} \qquad (5)$$

Where:

$FC_{f,y}$	Total volume of natural gas or other fuel 'f' combusted in the project plant (m^3 or similar) or other start up fuel in year(s) y
$COEF_{f,y}$	CO_2 emission coefficient (tCO_2/m^3 or similar) in year(s) y for each fuel 'f'

$$COEF_y = \sum NCV_y \cdot EF_{CO2,f,y} \cdot OXID_f \qquad (5a)$$

Where:

NCV_y	Net calorific value per volume unit of natural gas (GJ/m^3) in year y as determined from the fuel supplier, wherever possible, otherwise from local or national data;
$EF_{CO2,f,y}$	CO_2 emission factor per unit of energy of natural gas in year y (tCO_2/GJ), from IPCC;

$OXID_f$	Oxidation factor of natural gas

Leakage

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. Since the project activity does not use LNG, the leakage emissions are given as follows:

$$LE_y = LE_{CH4,y} \qquad (6)$$

Where:

LE_y	Leakage emissions during the year y in tCO_2e
$LE_{CH4,y}$	Leakage emissions due to fugitive upstream CH_4 emissions in the year y in tCO_2

Fugitive methane emissions

For the purpose of estimating fugitive CH_4 emissions, the quantity of natural gas consumed by the project in year y is multiplied with an emission factor for fugitive CH_4 emissions ($EF_{NG,upstream,CH4}$) from natural gas consumption and subtracted by the emissions from fossil fuels used in the absence of the project activity, as follows:

$$LE_{CH_4,y} = \left\lfloor FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH_4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH_4} \right\rfloor \cdot GWP_{CH_4} \qquad (7)$$

Where:

$LE_{CH_4,y}$	Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_2e
$FC_{NG,y}$	Quantity of natural gas combusted in the project plant during the year y in m^3
$NCV_{NG,y}$	Average net calorific value of the natural gas combusted during the year y in GJ/m^3
$EF_{NG,upstream,CH_4}$	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in tCH_4 per GJ fuel supplied to final consumers
$EG_{PJ,y}$	Electricity generation in the project plant during the year in MWh
$EF_{BL,upstream,CH_4}$	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in tCH_4 per MWh electricity generation in the project plant
GWP_{CH_4}	Global warming potential of methane valid for the relevant commitment period

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL,upstream,CH4}$) should be calculated consistent with the baseline emission factor - Option 2($EF_{BL,CO2}$). As presented in the Annex 3, the emission factor was found to be the lowest with Combined Margin method for the JAMALI grid, so the same calculation procedure has been adopted to calculate $EF_{BL,upstream,CH4}$, as presented below:

$$EF_{BL,upstream,CH_4} = 0.5 \cdot \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH_4}}{\sum_j EG_j} + 0.5 \cdot \frac{\sum_i FF_{i,k} \cdot EF_{k,upstream,CH_4}}{\sum_i EG_i} \quad (8)$$

Where:

$EF_{BL,upstream,CH_4}$	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in tCH_4 per MWh electricity generation in the project plant
j	Plants included in the build margin
$FF_{j,k}$	Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin
$EF_{k,upstream,CH_4}$	Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type) in tCH_4 per MJ fuel produced
EG_j	Electricity generation in the plant j included in the build margin in MWh/a
i	Plants included in the operating margin
$FF_{i,k}$	Quantity of fuel type k (a coal or oil type) combusted in power plant i included in the operating margin
EG_i	Electricity generation in the plant i included in the operating margin in MWh/a

As per AM0029, since the Combined Margin has been selected as the Baseline Emission Factor (Option 2), the factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity will be determined ex-post, and will be calculated in consistent with the Baseline Emission Factor, as described in *Tool to calculate emission factor for an electricity system.*

Table 11: Default emission factors for fugitive CH_4 upstream emissions

Parameter	**Default value**	**Unit**	**Source**	**Remarks**
$EF_{coal,upstream,CH4}$	0.8	tCH_4 /kt coal	Table 2 of AM0029: Default emission factors for fugitive CH_4 upstream emissions	Since the predominant sources in the region are currently using surface mining coal[31], the default emission factor value used is 0.8 tCH_4 /kt coal.
$EF_{oil,upstream,CH4}$	4.1	tCH_4 / PJ	Table 2 of AM0029: Default emission factors for fugitive CH_4 upstream emissions	This value includes production, transport, refining and storage of the oil.
$EF_{NG,upstream,CH4}$	296	tCH_4 / PJ	Table 2 of AM0029: Default emission factors for fugitive CH_4 upstream emissions	This value includes production, processing transport and distribution of natural gas. It is applicable for the rest of the world.

The calculation of leakage emissions are provided in Annex 5.

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[31] Source: http://www.energybangla.com/index.php?mod=article&cat=CoalSector&article=1531

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

Data / Parameter:	η_{NG}
Data unit:	%
Description:	Energy efficiency of the gas fired power plant running in combined cycle
Source of data used:	Statement letter from EPC contractor (PT INDO FUJ IENERGY) Bekasi - Heat Rate Statement letter
Value applied:	43.65%
Justification of the choice of data or description of measurement methods and procedures actually applied :	This data is used as inputs for calculating the estimated fuel consumption for ex-ante calculation. This document stated thermal efficiency of 7817.05 BTU/kWh which is equivalent to a rate of 43.65%, use to estimate the gas quantity required in MMBTU, this has been provided during the site visit.
Any comment:	-

Data / Parameter:	**Coal consumption in coal fired power plants in JAMALI region**
Data unit:	kilotonnes
Description:	Coal consumption in coal fired power plants in JAMALI region
Source of data used:	The source of data comes from the official data given by Indonesian Directorate General of Electricity and Energy Utilization. JAMALI Grid – Build Margin and Operating Margin calculation database.
Value applied:	see table below
Justification of the choice of data or description of measurement methods and procedures actually applied :	These data are used as inputs to calculate the Energy efficiency of the coal fired power plants. The same data is used to calculate the official JAMALI Grid
Any comment:	-

Coal Power Plant	**Quantity of fuel consumed (kilotonnes)**
Paiton I	4,437
Paiton II	4,273
Krakatau	0.8
Cilacap	764.1
Tanjung Jati B (PLN)	1,525
PT. PJB (PLN)	2,753
IP (PLN)	13,165

Data / Parameter:	**Electricity generated from Coal fired power plants in the JAMALI Grid**
Data unit:	GWh
Description:	Electricity generated from Coal fired power plants in the JAMALI Grid

<table>
<tr><td>Source of data used:</td><td>The source of data comes from the official data given by Indonesian Directorate General of Electricity and Energy Utilization. JAMALI Grid – Build Margin and Operating Margin calculation database.</td></tr>
<tr><td>Value applied:</td><td>
<table>
<tr><th>Coal Power Plant</th><th>Gross electricity generation (GWh)</th></tr>
<tr><td>Paiton I</td><td>9,116</td></tr>
<tr><td>Paiton II</td><td>9,109</td></tr>
<tr><td>Krakatau</td><td>2.2</td></tr>
<tr><td>Cilacap</td><td>1,937</td></tr>
<tr><td>Tanjung Jati B (PLN)</td><td>3,869</td></tr>
<tr><td>PT. PJB (PLN)</td><td>4,929</td></tr>
<tr><td>IP (PLN)</td><td>23,875</td></tr>
</table>
</td></tr>
<tr><td>Justification of the choice of data or description of measurement methods and procedures actually applied :</td><td>These data are used as inputs to calculate the Energy efficiency of the coal fired power plants The same data is used to calculate the official JAMALI Grid</td></tr>
<tr><td>Any comment:</td><td>-</td></tr>
</table>

Data / Parameter:	η_{BL}
Data unit:	%
Description:	Energy efficiency of the coal fired power plant
Source of data used:	Bekasi - GHG_JAWABALI_2006_DJLPE-FINAL.xls Official Information on Baseline Emission Factor in JAMALI Electricity Grid published by Indonesian Directorate General of Electricity and Energy Utilization.
Value applied:	31.8 %
Justification of the choice of data or description of measurement methods and procedures actually applied :	Calculated as the average of energy efficiency for the most recent coal fired power plant, connected to the JAMALI grid. Values used are fuel consumption, NCV of coal and net electricity generated and published by Indonesian Directorate General of Electricity and Energy Utilization.
Any comment:	This parameter has been fixed ex-ante to calculate Option 3 (baseline emission)

Data / Parameter:	NCV_y of Coal
Data unit:	TJ/Gg
Description:	Net calorific value of coal
Source of data used:	2006 IPCC Guidelines for National GHG Inv., vol, 2, Table 1.2, p.1.18 – (Other-Bituminous Coal - Default value)
Value applied:	25.8
Justification of the choice of data or	Default values for Carbon Emission Factor of Natural Gas as 2006 IPCC Guidelines for National Greenhouse Gas Inventories has been considered. This

description of measurement methods and procedures actually applied :	data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form.
Any comment:	-

Data / Parameter:	NCV_y of HSD, IDO and MFO
Data unit:	GJ/ kiloliter fuel
Description:	Net calorific value per volume unit.
Source of data used:	The document to support the NCV_y of HSD, IDO and MFO is Bekasi - GHG_JAWABALI_2006_DJLPE-FINAL.xls document provided by BPPT (Agency for the Assessment and Application of Technology, Indonesia).
Value applied:	Refer to Annex 5
Justification of the choice of data or description of measurement methods and procedures actually applied :	This data are used as inputs for calculating the Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity. The source of data comes from the data given by Indonesian Directorate General of Electricity and Energy Utilization. The same data is used to calculate the official JAMALI Grid.
Any comment:	-

Data / Parameter:	$EF_{CO2, Coal}$
Data unit:	Kg CO2e/TJ
Description:	CO2 emission factor of coal combustion
Source of data used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Table 2.2 page 2.16 (Other-Bituminous Coal - CO2 - Default value)
Value applied:	94,600
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default values for Carbon Emission Factor of Natural Gas as 2006 IPCC Guidelines for National Greenhouse Gas Inventories has been considered. This data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form.
Any comment:	-

Data / Parameter:	$EF_{NG,upstream,CH_4}$
Data unit:	tCH_4/PJ
Description:	Emission factor for upstream fugitive methane emissions of Natural Gas from production, transportation, distribution
Source of data used:	Available from methodology AM0029 Table 2 page 9
Value applied:	296
Justification of the choice of data or description of measurement methods	As per the methodology AM0029 Table 2 page 9

and procedures actually applied :	
Any comment:	-.

Data / Parameter:	$EF_{Oil,upstream,CH_4}$
Data unit:	tCH_4/PJ
Description:	Emission factor for upstream fugitive methane emissions of oil from production, transportation, distribution
Source of data used:	Available from methodology AM0029 Table 2 page 9
Value applied:	4.1
Justification of the choice of data or description of measurement methods and procedures actually applied :	As per the methodology AM0029 Table 2 page 9
Any comment:	-.

Data / Parameter:	$EF_{Coal,upstream,CH_4}$
Data unit:	tCH_4/kt Coal
Description:	Emission factor for upstream fugitive methane emissions of coal from production, transportation, distribution
Source of data used:	Available from methodology AM0029 Table 2 page 9
Value applied:	0.8
Justification of the choice of data or description of measurement methods and procedures actually applied :	As per the methodology AM0029 Table 2 page 9
Any comment:	-.

Data / Parameter:	**GWP (CH_4)**
Data unit:	-
Description:	Global warming potential of methane
Source of data used:	Established by Kyoto Protocol
Value applied:	21
Justification of the choice of data or description of measurement methods and procedures actually applied :	Established by Kyoto Protocol for First Commitment Period
Any comment:	-

B.6.3 Ex-ante calculation of emission reductions:

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As per methodology AM0029, the emission reductions by the project activity is calculated as follows:

$$ER_y = BE_y - PE_y - LE_y$$

Where:

ER_y	Emissions reductions in year y (t CO_2e)
BE_y	Emissions in the baseline scenario in year y (tCO_2e)
PE_y	Emissions in the project scenario in year y (tCO_2e)
LE_y	Leakage in year y (t CO_2e)

Baseline Emissions

Baseline Emissions (tCO_2e): $BE_y = EG_{PJ,y}\ .\ EF_{BL,CO_2,y}$

Where:

$EG_{PJ,y}$ = Annual expected net electricity generated in the project activity (MWh)

= Gross electricity generated – Auxiliary power consumption

$EG_{PJ,y}$ = 8640[32]*0,85*(2*37,97+50) - 8640*0,85*(2*1,4+1,8)

$EG_{PJ,y}$ = 891,070 MWh

And baseline emission factor value is:

$EF_{BL,CO_2,y}$ = 0.891 tCO2e/MWh (Refer to section B.6.1. Option 2)

Therefore baseline emission is:

$BE_y =$ 891,070 * 0.891

$BE_y =$ **793,944 tCO2e**

Project Emissions

$$PE_y = \sum FC_{f,y} \cdot COEF_{f,y} \qquad (5)$$

$$PE_y = FC_{NG,y} \cdot COEF_{NG,y} + FC_{HSD,y} \cdot COEF_{HSD,y}$$

Where:

$FC_{NG,y}$	Total volume of natural gas combusted in the project plant (m^3 or similar) in year
$COEF_{NG,y}$	CO_2 emission coefficient (tCO_2/m^3 or similar) in year y for natural gas
$FC_{HSD,y}$	Total volume of diesel oil combusted in the project plant (m^3 or similar) in year
$COEF_{HSD,y}$	CO_2 emission coefficient (tCO_2/m^3 or similar) in year y for diesel oil

---

[32] 8640 hours/year, the remaining 5 days the plant will be shut down for maintenance services.

And

$$COEF_{NG,y} = NCV_{NG,y} \cdot EF_{CO2,NG,y} \cdot OXID_{NG} \qquad (5a)$$

$COEF_{NG,y}$ = 0.03654 * 0.0561 * 1

$COEF_{NG,y}$ = 0.00205 tCO_2/m^3

$$PE_y = FC_{NG,y} \cdot COEF_{NG,y} + FC_{HSD,y} \cdot COEF_{HSD,y}$$

For Ex-ante project emission calculation, $FC_{HSD,y}$ has been considered nil.

Then

$$PE_y = FC_{NG,y} \cdot COEF_{NG,y}$$

PE_y = 208,759,413 * 0.00205

PE_y = **427,934 tCO_2e**

Leakage

Leakage emissions due to fugitive upstream CH_4 emissions (refer to Annex 5 for details of calculation)

$$LE_{CH_4,y} = \left[FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH_4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH_4}\right] \cdot GWP_{CH_4} \qquad (7)$$

LE_y = [208,759,413 * 0.03654 * 0.000296 – 891,121 * 0.000473]* 21

LE_y = **38,566 tCO_2e**

Emissions reductions

$$ER_y = BE_y - PE_y - LE_y$$

ER_y = 793,944 - 427,934 - 38,566

ER_y **= 327,443 tCO_2e**

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

>>

A summary of the ex-ante estimation of emission reductions for all years of the crediting period has been presented in the table below.

Year	**Estimation of project activity emissions (tCO_2e)**	**Estimation of baseline emissions (tCO_2e)**	**Estimation of leakage (tCO_2e)**	**Estimation of overall emission reductions (tCO_2e)**
Sept 2010 - Dec 2010	142,645	264,648	12,855	109,148
2011	427,935	793,944	38,566	327,443
2012	427,935	793,944	38,566	327,443
2013	427,935	793,944	38,566	327,443
2014	427,935	793,944	38,566	327,443
2015	427,935	793,944	38,566	327,443

2016	427,935	793,944	38,566	327,443
2017	427,935	793,944	38,566	327,443
2018	427,935	793,944	38,566	327,443
2019	427,935	793,944	38,566	327,443
Jan 2020 - Aug 2020	285,290	529,296	25,710	218,296
Total (tCO_2e)	**4,279,347**	**7,939,437**	**385,656**	**3,274,435**

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

>>

Monitoring methodology and monitoring plan for the project activity has been prepared using the guideline provided in Approved monitoring methodology AM0029 Version 03, “Grid Connected Electricity Generation Plant using Non- Renewable and Less GHG Intensive Fuel”.

The applicability of this methodology to the proposed CDM project activity has been discussed in Section B.2 above.

All the data to be monitored to estimate project, baseline and leakage emissions for verification and issuance will be kept for two years after the end of the crediting period or the last issuance of CERs for the project activity, whichever occurs later.

The primary parameters to be monitored for calculating project emissions are listed below. Other parameters will be calculated using the primary parameters.

For project emissions:

1. Annual fuel (s) consumption in project activity.
2. Net Caloric Values (s) of the fuel used in the project activity.
3. Fuel emission factors for fuel used in the project activity.

High Speed Diesel (HSD) could be used in both gas turbine and diesel generator. The HSD could be used in gas turbine at the start-up and in case of emergencies such as disruption of gas supply. Diesel generator also could be run periodically as back-up for warming up and during emergencies. But as per the applicability of AM0029, *Natural Gas should be the primary fuel. Small amounts of other start-up or auxiliary fuels can be used, but can comprise no more than 1% of total fuel use, on energy basis*.

B.7.1 Data and parameters monitored:

>>

The following tables include specific information on how the data and parameters that need to be parameters would actually be collected during monitoring for the project activity.

Data / Parameter:	$FC_{NG,y}$
Data unit:	m^3
Description:	Natural gas combusted in the project activity during the year y
Source of data to be used:	Measurements at the project activity

Value of data applied for the purpose of calculating expected emission reductions in section B.6	208,759,413
Description of measurement methods and procedures to be applied:	The volume of natural gas is measured using the flow through the inlet feeder. This data will be collected continuously. The meter reading will be archived as daily report and will be projected in the monthly and yearly report. The natural gas consumption metering is done by using two main meters and two check meters. The main meters are installed and owned by the Gas Supplier and check meters are installed and owned by Bekasi Power. The main meters and check meters are installed both in the gas pipeline of PGN and BBG at the gas compression facility area. The natural gas flow meters owned by PGN and BBG will both measure the total natural gas combusted by the project activity. The meters shall be deemed to be working satisfactory if the errors are within specifications of meters. The turbine meter accuracy 1 % of Qmin to 0.2 Qmax and 0.5 % of 0.2 Qmax to Qmax.
QA/QC procedures to be applied:	This can be crosschecked against the supplier receipts The natural gas meter shall be tested for accuracy once a year against an accepted laboratory standard meter in accordance with prescribed standards. Calibration / test of the natural gas meters shall be done by Directorate of Meteorology of Ministry of Trade of Republic Indonesia as relevant standard. All the calibration certificates including that of the master laboratory meter shall be maintained by the project participant.
Any comment:	-

Data / Parameter:	$FC_{HSD,y}$
Data unit:	m^3
Description:	Quantity of High Speed Diesel (HSD) combusted in the project activity during the year y.
Source of data to be used:	Measurements at the project activity
Value of data applied for the purpose of calculating expected emission reductions in section B. 6	For ex-ante calculation, HSD consumption is considered nil.
Description of measurement methods and procedures to be applied:	As HSD could be used only for start-up and during emergencies such as disruption of gas, the monitoring using level gauge meter will occur as and when HSD is used.
QA/QC procedures to	This can be crosschecked against the supplier receipts

be applied:	
Any comment:	-

Data / Parameter:	$NCV_{NG,y}$
Data unit:	GJ/m^3
Description:	Net calorific value of Natural gas in year y
Source of data to be used:	Fortnightly fuel supplier data
Value of data applied for the purpose of calculating expected emission reductions in section B.6	0.03654
Description of measurement methods and procedures to be applied:	Net Calorific Value of Natural gas will be calculated from the Gross Calorific Value provided by the fuel supplier Data will be recorded and archived electronically/paper by project proponent fortnightly.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned.
Any comment:	-

Data / Parameter:	$NCV_{HSD,y}$
Data unit:	GJ/m^3
Description:	Net calorific value of HSD in year y
Source of data to be used:	Fortnightly fuel supplier data
Value of data applied for the purpose of calculating expected emission reductions in section B.6	As HSD consumption is considered nil, net calorific value of HSD is nil.
Description of measurement methods and procedures to be applied:	Net Calorific Value of HSD will be calculated from the Gross Calorific Value provided by the fuel supplier Data will be recorded and archived electronically/paper by project proponent fortnightly.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned.
Any comment:	-

Data / Parameter:	$OXID_{NG}$
Data unit:	-
Description:	Oxidation Factor of Natural Gas
Source of data to be used:	Volume 2 (Energy) - Chapter 1- Table 1.4 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories
Value of data applied	1

for the purpose of calculating expected emission reductions in section B.6	
Description of measurement methods and procedures to be applied:	Default values as 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual has been considered. This data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	Oxidation factor of Natural Gas will be updated as per the latest guidelines available from IPCC on national greenhouse gas inventory on year to year basis.

Data / Parameter:	$OXID_{HSD}$
Data unit:	-
Description:	Oxidation Factor of HSD
Source of data to be used:	Volume 2 (Energy) - Chapter 1- Table 1.4 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories
Value of data applied for the purpose of calculating expected emission reductions in section B.6	1
Description of measurement methods and procedures to be applied:	Default values as 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual has been considered. This data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, whichever occurs later.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	Oxidation factor of HSD will be updated as per the latest guidelines available from IPCC on national greenhouse gas inventory on year to year basis.

Data / Parameter:	$EF_{CO_2,NG}$
Data unit:	kg CO_2e/TJ
Description:	CO_2 Emission Factor of Natural Gas
Source of data to be used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Table 2.2 page 2.16 (Natural Gas - CO_2 - Default value)
Value of data applied for the purpose of calculating expected emission reductions in section B.6	56,100
Description of	Default values for Carbon Emission Factor of Natural Gas as 2006 IPCC

measurement methods and procedures to be applied:	Guidelines for National Greenhouse Gas Inventories has been considered. This data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	Carbon Emission factor of natural gas will be updated as per the latest guidelines available from IPCC on national greenhouse gas inventory on year to year basis.

Data / Parameter:	$EF_{CO_2,HSD}$
Data unit:	kg CO_2e/TJ
Description:	CO_2 Emission Factor of HSD
Source of data to be used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Table 2.2 page 2.16 (Diesel oil - CO_2 - Default value)
Value of data applied for the purpose of calculating expected emission reductions in section B.6	74,100
Description of measurement methods and procedures to be applied:	Default values for Carbon Emission Factor of Natural Gas as 2006 IPCC Guidelines for National Greenhouse Gas Inventories has been considered. This data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	Carbon Emission factor of natural gas will be updated as per the latest guidelines available from IPCC on national greenhouse gas inventory on year to year basis.

Data / Parameter:	$COEF_{NG,y}$
Data unit:	tCO_2/m^3
Description:	CO_2 Emission Coefficient of Natural Gas
Source of data to be used:	Calculated on PEy based on $NCV_{NG,y}$, $OXID_{NG}$ and $EF_{CO_2,NG}$
Value of data applied for the purpose of calculating expected emission reductions in section B.6	0.002
Description of measurement methods and procedures to be applied:	As per calculation according to the methodology: $COEF_y = NCV_y \cdot EF_{CO2,y} \cdot OXID_f$
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned

Any comment:	-

Data / Parameter:	$COEF_{HSD,y}$
Data unit:	tCO_2/m^3
Description:	CO_2 Emission Coefficient of HSD
Source of data to be used:	Calculated on PEy based on $NCV_{HSD,y}$, $OXID_{HSD}$ and $EF_{CO_2,HSD}$
Value of data applied for the purpose of calculating expected emission reductions in section B.6	As HSD consumption is considered nil, CO_2 Emission Coefficient of HSD is nil.
Description of measurement methods and procedures to be applied:	As per calculation according to the methodology: $COEF_y = NCV_y \cdot EF_{CO2,y} \cdot OXID_f$
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	-

Data / Parameter:	PE_y
Data unit:	tCO_2e
Description:	Emissions in the project scenario in year y
Source of data to be used:	Calculated based on $FC_{NG,y}$, $COEF_{NG,y}$ and $FC_{HSD,y}$, $COEF_{HSD,y}$
Value of data applied for the purpose of calculating expected emission reductions in section B.6	427,934
Description of measurement methods and procedures to be applied:	As per calculation according to the methodology: $PE_y = \sum FC_y \cdot COEF_y$
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	-

Baseline emission

Data / Parameter:	$EF_{BM,y}$
Data unit:	tCO_2/MWh
Description:	Build Margin Emission factor of JAMALI Grid

Source of data to be used:	Excel spreadsheet calculation from DJLPE. Official Information on Baseline Emission Factor in JAMALI Electricity Grid by Ministry of Environment of Indonesia dated January 19, 2009 (Bekasi - GHG_JAWABALI_2006_DJLPE-FINAL.xls)
Value of data applied for the purpose of calculating expected emission reductions in section B.6	0.973
Description of measurement methods and procedures to be applied:	In line with the ex-post determination of the baseline emission factor the Build Margin will be updated annually ex-post. No measurement required, Build Margin Emission Factor is estimated from DJLPE official Information.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned.
Any comment:	-

Data / Parameter:	$EF_{OM,y}$
Data unit:	tCO_2/MWh
Description:	Operating Margin Emission factor of JAMALI Grid
Source of data used:	Excel spreadsheet calculation from DJLPE. Official Information on Baseline Emission Factor in JAMALI Electricity Grid by Ministry of Environment of Indonesia dated January 19, 2009 (Bekasi - GHG_JAWABALI_2006_DJLPE-FINAL.xls)
Value of data applied for the purpose of calculating expected emission reductions in section B.6	0.844
Description of measurement methods and procedures to be applied:	In line with the ex-post determination of the baseline emission factor the Operating Margin will be updated annually ex-post. No measurement required, Operating Margin Emission Factor is estimated from DJLPE official Information.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned.
Any comment:	-

Data / Parameter:	$EF_{CM,y}$
Data unit:	tCO_2/MWh
Description:	Combined Margin Emission Factor for JAMALI grid
Source of data to be used:	Calculated based on $EF_{OM,y}$ and $EF_{BM,y}$
Value of data applied	0.891 tCO_2/MWh

for the purpose of calculating expected emission reductions in section B.6	
Description of measurement methods and procedures to be applied:	As per calculation according to the methodology: $EF_{CM,y} = 50\% * EF_{OM,y} + 50\% * EF_{BM,y}$ Also available from Indonesian DNA website http://dna-cdm.menlh.go.id/Downloads/Others/KomnasMPB_Grid_Sumatera_JAMALI_2008.pdf
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned.
Any comment:	-.

Data / Parameter:	**Gross electricity generation**
Data unit:	MWh
Description:	Gross electricity generated
Source of data to be used:	Measurements at the industrial facility
Value of data applied for the purpose of calculating expected emission reductions in section B.5	924,903 per annum
Description of measurement methods and procedures to be applied:	The gross electricity generation will be measurements by energy meter installed at the project activity. The meter reading will be archived as daily report and will be projected in the monthly and yearly report. The meters shall be deemed to be working satisfactory if the errors are within specifications for meters with the accuracy of direct connected class 1, transformer connected class 0.2s up to class 0.5s, and reactive energy class 1 or class 2.
QA/QC procedures to be applied:	The energy meter shall be tested for accuracy at least once a year against an accepted laboratory standard meter in accordance with electricity standards by an accredited third party (Agency of Trade and Industry – West Java Province).
Any comment:	-

Data / Parameter:	**Auxiliary Consumption**
Data unit:	MWh
Description:	Auxiliary consumption of the cogeneration system
Source of data to be used:	Measurements at the project activity
Value of data applied for the purpose of calculating expected emission reductions in section B.5	33,833 per annum

Description of measurement methods and procedures to be applied:	The auxiliary consumption will be measurements by energy meter installed at the project activity. The meter reading will be archived as daily report and will be projected in the monthly and yearly report.
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned.
Any comment:	-

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh
Description:	Net electricity exported to the grid by the project activity in the year y
Source of data to be used:	Measurements at the project activity
Value of data applied for the purpose of calculating expected emission reductions in section B.6	891,070 per annum
Description of measurement methods and procedures to be applied:	Electricity supplied to PLN will be metered at the point of delivery and is therefore net of transmission losses. All data will be transmitted electronically back to a master meter at the plant. The daily reading at the master meter will be archived electronically. Data archives will be maintained for two years after the end of the crediting period.
QA/QC procedures to be applied:	The net electricity generated will also be cross checked with that calculated as the difference between the gross electricity generated and auxiliary consumption.
Any comment:	-

Leakage emissions

Data / Parameter:	$EF_{BL,upstream,CH_4}$
Data unit:	tCH_4/MWh
Description:	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation
Source of data to be used:	Available national/regional data
Value of data applied for the purpose of calculating expected emission reductions in section B.6	0.000473 tCH_4/MWh
Description of measurement methods and procedures to be applied:	$EF_{BL,upstream,CH_4}$ is calculated for power plants included Combined Margin, in line with the baseline emission factor selection. Therefore in line with the AM0029 requirement of ex-post determination of the Build Margin, the Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation (tCH_4 or tCO_2e/MWh) will

	also be determined ex-post. This data will be computed annually based on latest available information and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, whichever occurs later
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned.
Any comment:	-.

B.7.2 Description of the monitoring plan:

>>

The Monitoring and Verification (M&V) procedures define a project-specific standard against which the project's performance (i.e. GHG reductions) and conformance with all relevant criteria will be monitored and verified. It includes developing suitable data collection methods and data interpretation techniques for monitoring and verification of GHG emissions with specific focus on technical performance parameters. It also allows scope for review, scrutiny and benchmarking of all this information against reports pertaining to M & V protocols.

The monitoring plan is prepared considering in following areas of Project Activity:

1. Establishing and maintaining the appropriate monitoring systems for consumption of NG and electricity generated by the proposed project.
2. Quality control at Project Activity and measurements.
3. Assigning monitoring responsibilities to personnel.
4. Data storage and filing system.

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

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The baseline study and application of baseline methodology was completed on 01/01/2009
by:
Donald Gautier, PT Agrinergy Indonesia. Not a project participant.
Contact information: PT Agrinergy Indonesia. Wisma Pondok Indah 2, 17th floor, Suite 1711. Jalan Sultan Iskandar Muda Kav V-TA, Jakarta 12310. Tel. +62 21 7592 2999

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:

>>
09/07/2007 EPC contract

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

>>
25 years 00 months

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:

>>
NA

C.2.1.2. Length of the first crediting period:

>>
NA

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>>
01/09/2010 or date of registration (whichever is later)

C.2.2.2. Length:

>>
10 years 00 months

SECTION D. Environmental impacts

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

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PT Bekasi Power implemented an Environmental Impact Assessment (EIA) /*Analisa Mengenai Dampak Lingkungan* (AMDAL) in compliance with the environmental regulations: Law Number 23 Year 1997 about Environmental Management and Regulation of the State Minister of Environment Number 8 Year 2006 about Writing Guidelines of EIA. The EIA is the revision of earlier EIA in April 1999 of Jababeka Industrial Estate Phase III, where PT Bekasi Power is located. This EIA has been approved by Governor of West Java Province in 19th May 2008.

The construction project of the PLTGU is consisted of 3 phases: pre-construction (preparation), construction and operational phase. The preparation phase comprises of several activities such as engineering preparation, involving feasibility study, permit process and confirmation of gas supply. Construction process involves material and heavy equipment transports, land opening and processing, work force mobilization, construction of ME and demobilization of heavy equipments. Operational process involves work force mobilization, commissioning, gas supply, operations of the power plant, waste treatment and maintenance.

Table 12: Construction Phase

Environmental Component	Possible Impacts	Environmental Management Plan
Air Quality	Decreasing air quality due to the increase of gas wastes (HC, CO_2, NO_x, and SO_2) and dust due to various construction activities.	• Managing the truck loading schedule • Localizing source of impact by installing fences around the construction site • Frequent maintenance of soil excess around the construction site and spraying around the construction site to reduce the amount of dust
Noise	Noise and vibration resulted from the usage of machines such as compactor, bulldozer, back hoe, excavator and other construction equipment.	• Project schedule management • Foundation construction plan utilizes the Bore Pile method
Surface water	Material/soil excess and liquid waste, resulting from the workers domestic activities.	• Maintenance of drainage plan to mitigate waste risk and sedimentation due to construction activities. • Liquid waste management (lubricating oil & domestic waste)
Local fidgetiness	Risk of local complaints due to the declining air quality, noise pollution and traffic	• To provide hotline service for response purposes and inputs from locals
Employment and business opportunity	The locals will benefit from employment demands and increase of per-capita income from the	• To provide priority for locals by considering the work qualification required in the project.

	existence of the project activity	• To inform the locals concerning employment opportunity and the requirements necessary. • To provide wage in accordance with the applicable standard, education level and work expertise

Table 13: Operation Phase

Environmental Component	Possible Impacts	Environmental Management Plan
Air quality	The existence of gas pollution containing CO_2, NO_x, H_2O and hot air.	• Constructing Buffer Zone along the inhabitant borders with wall of 4 meters tall and to plant pollutant absorbing vegetation. • Plantation of trees with high lushness factor such as mahogany, rubber tree, etc. • To conduct flare stack air up to 20 meters high in order to mitigate over pressured gas risk. • There will be no exhaust treatment to reduce the emission from turbines. PT Bekasi will monitor the gas emission accordingly to the EIA and exhausted gases from turbines are expected to be far below the threshold limit. Therefore, all GT emissions are in compliance with regulation and requirement from Indonesian Minister of Environment and will remain below legal values.
Noise	Noisy from blow down action	• Instalments of latex absorber to cover the joints of windows and doors. • To install noise emitting machines in a noise absorbent building. • To cover the production machines in order to reduce noise emission. • To instruct employees to wear earplugs.
Surface water	Liquid waste from domestic activity operation and waste oil Hazardous waste in form of waste oil and lubricant	• The liquid waste will be transmitted to the containment tube before being directed to the liquid waste treatment unit for industrial area. • Waste oil and lubricant are contained in an oil catcher. The waste is then gathered into sealed drums and handed over to third parties that possess the permit from the Ministry of Environment.
Solid waste	Solid waste produced from	• Waste is managed through selection of

	domestic activities	organic and non organic waste. The waste is collected and transported by cleaning units everyday, which then will be transported to the final disposal site.
Local fidgetiness	Risk of local complaints due to the declining air quality, noise pollution and traffic	To provide hotline service for response purposes and inputs from locals
Employment and business opportunity	The locals will benefit from employment demands and increase of per-capita income from the existence of the project activity	• To provide priority for locals by considering the work qualification required in the project. • To inform the locals concerning employment opportunity and the requirements necessary. • To provide wage in accordance with the applicable standard, education level and work expertise

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

\>>

There are no significant environmental impacts of the project.

SECTION E. Stakeholders' comments

>>

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

>>

PT Bekasi Power applied/ communicated to the relevant stakeholders to comment on the project activity. The stakeholder list includes the government and non-government parties, which are involved in the project activity at various stages. All the identified stakeholders are invited by PT Bekasi Power by sending written letters explaining the purpose of the meeting. PT Bekasi Power also posted a notice in a local newspaper on 09/05/2008 for announcing the stakeholder meeting to the public. The notice indicated the agenda of meeting, venue and time of meeting. PT Bekasi Power then conducted the stakeholder consultation process in an open and transparent manner on 15/05/2008 at President Executive Club- Bekasi. They have invited all identified stakeholder explaining clearly about the project and sought their view on the project. The meeting was attended by the representatives of the identified stakeholders. The list of participants with their signature and comments are kept for record and photographs of the event were also taken. These were provided to the DOE during the validation.

The stakeholders identified for the project are as under.

- Deputy of Regent of Bekasi Regency
- Chief of Tanjung Sari Village, North Cikarang Subdistrict
- Elected body of representative administering the local area (village Tanjung Sari)
- Chief of Environmental Control & Mining Agency, Bekasi Regency
- Chief of Police of North Cikarang Sektor (Representative)
- Gas Supplier (PGN and BBG)
- Contractor
- Local community

The agenda of the stakeholder consultation included:

- Presentation of Project activity by PT Bekasi Power
- Analysis of CDM project and sustainable benefits by PT Agrinergy
- Open discussion and question and Answer session

E.2. Summary of the comments received:

>>

There were a number of comments received from the stakeholders attending the meeting. These have been summarized below:

Table 14: Comments received from the stakeholders

	Comments	**From**
1.	PT Bekasi Power is expected to conduct reforestation in the project area and around the project location especially in critical area, to reduce negative impact from the waste gas emission from the power plant and also to support the Million Tree project in Bekasi Regency.	Mr.Drs.Bambang Sulaksana, MM (Chief of Environmental Control & Mining Agency, Bekasi Regency)
2.	The locals expect that the negative impact to the society will be mitigated in regards to the construction and operation of the power plant. Mr Nuraedi also raised following questions:	Mr.Nuraedi (Representative of Tanjung Sari Community)

	a. Will there be any inspection conducted routinely to ensure that the project will not generate negative impact? b. Will the electricity generated by the power plant available for sale to the community?	
3.	The authority expects that PT Bekasi Power can mitigate safety risks in relation to the community and environment and also to encourage the community to purse alternative dispute resolution if there exists an issue between them and PT Bekasi Power. Due to its vital nature, the authority will also secure the site professionally based on the standard security procedure.	Iptu Sawon (Representative of Chief of Police of North Cikarang Sector)
4.	Will the project benefit the industry and the society by providing employment opportunity to the locals?	Edi Efendi (Representative of Tanjung Sari Community)

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

>>

Following are the responses on the comments:

Table 15: Responses on the comments

No	Answers
1.	PT Bekasi Power has conducted reforestation including critical areas in Bekasi Region to mitigate negative impact generated from the disposal of waste gas emission of the power plant
2.	PT Bekasi Power will ensure that the negative impacts will be mitigated from the development and operation of the power plant by applying technical expertise, such as selective usage of pipe and implant of pipe. Aside from that, according to the Clean Development Mechanism (CDM), the power plant project will be monitored routinely alongside with verification process. The electricity generated by the power plant is intended for industrial purposes at Jababeka Region, 3rd phase. The contractor ensures that the construction and operation of the power plant will apply safety procedures and healthy work environment. Negative impact will also be mitigated using technical methods such as automatic shutdown mechanism, should leakage occur to the systematically monitored device. In addition, the project will also utilize devices to monitor waste gas emission
3.	PT Bekasi Power is grateful for the support from the authority and also expects similar support from all parties in order to materialize the continuity of the project
4.	While generating benefit to the society by reducing Greenhouse gas emission through the usage of a clean fuel the project will also bring social and economic benefit by increasing employment opportunity to the community both directly and indirectly.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	PT Bekasi Power
Street/P.O.Box:	Jalan Niaga RayaKav 1-4
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City:	Bekasi
State/Region:	Cikarang Baru
Postfix/ZIP:	17550
Country:	Indonesia
Telephone:	(021) 8984 1770 /72 /73
FAX:	(021) 8984 1911
E-Mail:	
URL:	http://www.jababeka.com
Represented by:	Teguh Setiawan
Title:	Managing Director
Salutation:	Mr.
Last Name:	
Middle Name:	
First Name:	
Department:	
Mobile:	
Direct FAX:	(021) 572 7338
Direct tel:	(021) 572 7337
Personal E-Mail:	teguh.setiawan@jababeka.com

Organization:	Agrinergy Pte Ltd
Street/P.O.Box:	10 Hoe Chiang Road
Building:	#08-04 Keppel Towers
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State/Region:	
Postfix/ZIP:	089315
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FAX:	+65 6592 0401
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URL:	www.agrinergy.com
Represented by:	
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Mobile:	
Direct FAX:	+65 6592 0401
Direct tel:	+65 6592 0400
Personal E-Mail:	ben.atkinson@agrinergy.com

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No public funds have been used in the project activity.

Annex 3

BASELINE INFORMATION

Grid Emission Factors

The Operating Margin data for the most recent three years and Build Margin data for the Jawa Madura Bali (JAMALI) Grid based on database in Directorate General of Electricity and Energy Utilization and approved by Ministry of Environment of Indonesia are as follows:

Average Operating Margin

Total GHG emission in 2004, 2005, 2006 (tCO_2)	243,312,048
Total net electricity produced in 2004, 2005, 2006 (MWh)	288,316,859
Average Operating Margin for the most recent three years (tCO_2/MWh)	**0.844**

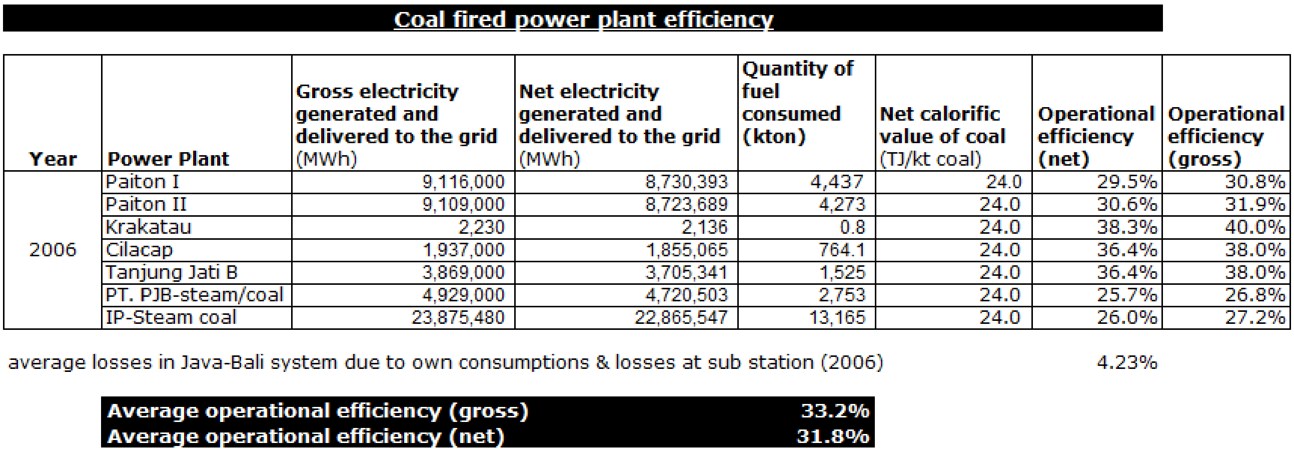
Build Margin

Total GHG emission in 2006 (tCO_2)	27,161,539
Total net electricity produced in 2006 (MWh)	28,937,555
Build Margin (tCO_2/MWh)	**0.937**

Combined Margin

Build Margin (tCO_2/MWh) (50%)	0.937
Average Operating Margin (tCO_2/MWh) (50%)	0.844
Combined Margin (tCO_2/MWh)	**0.891**

Calculation of energy efficiency of coal fired power plant[33]



Coal fired power plant efficiency

Year	Power Plant	Gross electricity generated and delivered to the grid (MWh)	Net electricity generated and delivered to the grid (MWh)	Quantity of fuel consumed (kton)	Net calorific value of coal (TJ/kt coal)	Operational efficiency (net)	Operational efficiency (gross)
2006	Paiton I	9,116,000	8,730,393	4,437	24.0	29.5%	30.8%
	Paiton II	9,109,000	8,723,689	4,273	24.0	30.6%	31.9%
	Krakatau	2,230	2,136	0.8	24.0	38.3%	40.0%
	Cilacap	1,937,000	1,855,065	764.1	24.0	36.4%	38.0%
	Tanjung Jati B	3,869,000	3,705,341	1,525	24.0	36.4%	38.0%
	PT. PJB-steam/coal	4,929,000	4,720,503	2,753	24.0	25.7%	26.8%
	IP-Steam coal	23,875,480	22,865,547	13,165	24.0	26.0%	27.2%

average losses in Java-Bali system due to own consumptions & losses at sub station (2006)	4.23%

Average operational efficiency (gross)	**33.2%**
Average operational efficiency (net)	**31.8%**

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[33] Source: Bekasi - GHG_JAWABALI_2006_DJLPE-FINAL.xls (Official document publicly available, provided by DNA upon demand)

Annex 4

MONITORING INFORMATION

The general conditions set out in this monitoring plan for metering, recording, meter inspections, test & checking; and communication shall be applicable for both electrical energy and natural gas, where relevant and applicable. The monitoring and controls are part of Distributed Control System (DCS) of entire plant. All monitoring and control functions are done as per the internally accepted standards and norms.

I. Monitoring of Parameters:

The parameters that would be monitored for PEy are:

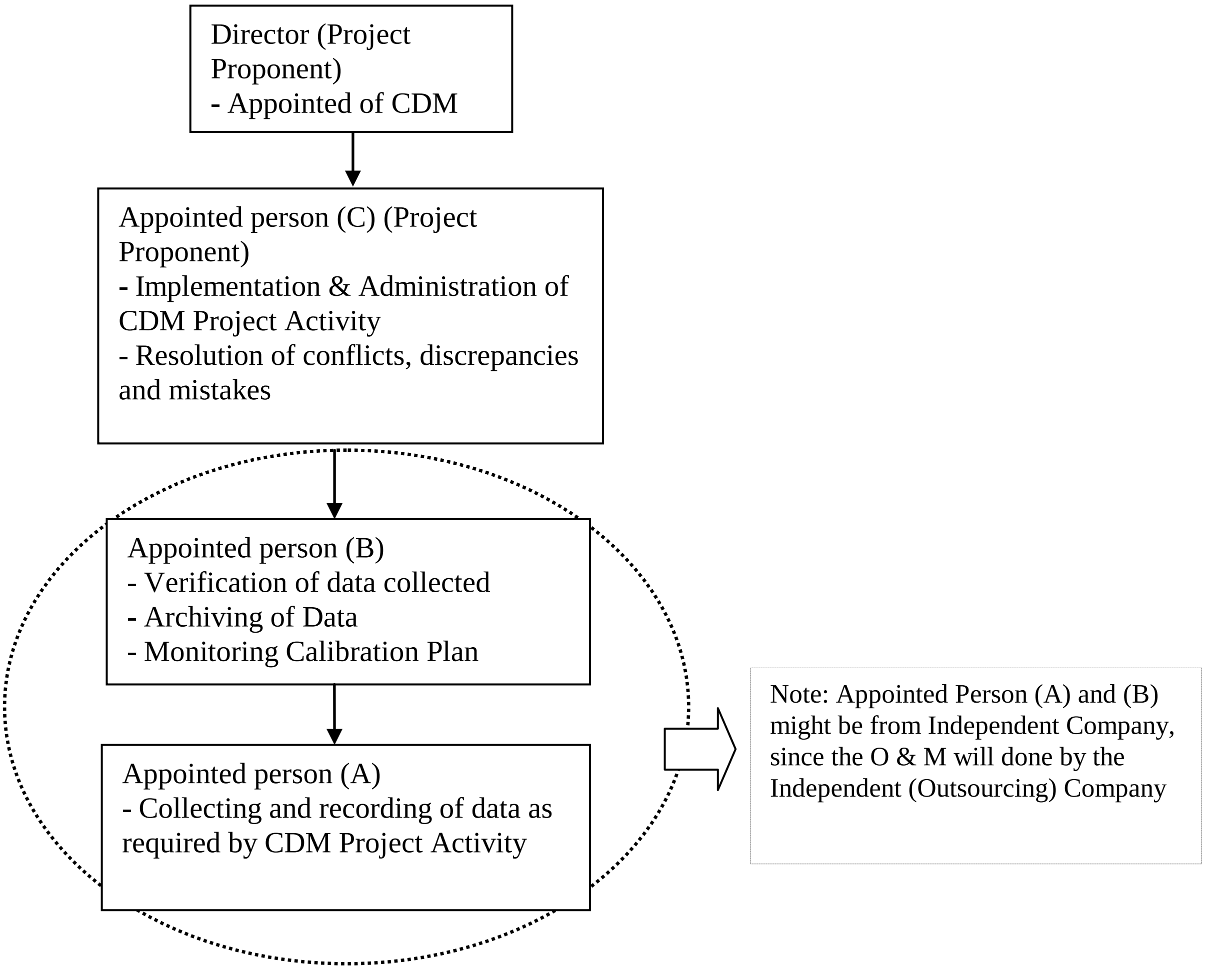
1. **Natural Gas Consumption ($FC_{NG,y}$)**: Measured
2. **Diesel Consumption ($FC_{HSD,y}$)**: Measured
3. **Net Calorific Value of Natural Gas ($NCV_{NG,y}$)**: Estimated
4. **Net Calorific Value of HSD ($NCV_{HSD,y}$):** Estimated
5. **Oxidation Factor of Natural Gas ($OXID_{NG}$):** Estimated
6. **Oxidation Factor of Diesel ($OXID_{HSD}$):** Estimated
7. **CO_2 Emission Factor of Natural Gas ($EF_{CO2,NG}$):** Estimated
8. **CO_2 Emission Factor of Diesel ($EF_{CO2,HSD}$):** Estimated
9. **CO_2 Emission Coefficient of Natural Gas ($COEF_{CO2,NG}$):** Calculated
10. **CO_2 Emission Coefficient of Diesel ($COEF_{CO2,HSD}$):** Calculated

11. **Project emissions (PE_y):** Calculated
12. **Build Margin Emission factor ($EF_{BM,y}$):** Estimated
13. **Operating Margin Emission factor ($EF_{OM,y}$):** Estimated
14. **Combined Margin Emission factor ($EF_{CM,y}$):** Estimated
15. **Gross Electricity Generation**: Measured
16. **Auxiliary Consumption**: Measured
17. **Net Electricity Generation ($EG_{PJ,y}$)**: Measured

18. **Emission Factor for upstream fugitive CH_4 emissions ($EF_{BL, upstream, CH4}$):** Estimated

II. Team for CDM Monitoring Plan Implementation:

The organization structure and division of responsibilities for implementation of CDM project activity is described below:



Director shall be responsible for appointment of CDM team for the implementation of CDM project activity. Any change in the CDM team composition or responsibilities shall be notified by Director.

Project proponent will outsource an independent company to do O&M (Operation and Maintenance) of the power plant.

The Appointed (A) person shall be responsible for collecting and recording all the data as required by the PDD and monitoring plan.
The Appointed person (B) is responsible for verifying the data collected and recorded on a day to day basis and archiving of the data. He is also responsible for ensuring the calibration of all the instruments are done according to the schedule and the requirement of monitoring plan.

The Appointed person (C) is responsible for the overall implementation & administration of the monitoring plan. Conflicts, Discrepancies, Mistakes etc in relation to the monitoring plan of the CDM project activity shall be referred to appointed person (C) for resolution and his resolution in this regard shall be final and binding.

III. Operation and Maintenance

The plant will be operated based on operation procedures to maintain the reliability and quality of electricity. Operation procedures are based on automation and centralized controls, which give the CCPP the flexibility and rapidity of response specific to the plant. Overall plant operation and supervisions is coordinated from the main control room. There are CRT operator stations in the main control room. From the main control room in the main control building the operator can operate the combined cycle system.

PT Bekasi Power will hire a specialized company as a third party to do the long term maintenance of the turbines. In practice the third party will obtain PT Bekasi Power approval for any maintenance undertaken. The maintenance is mean to support the operational system in order to maintain the system operation in an optimal performance, at least to meet the original conditions. The maintenance which followings the appropriate guidance, effective and good management, will present high reliability and justified costs. Total maintenance that will be provided for a power plant and its supporting facilities will prevent damage or restore the plant and its facilities to normal condition.

IV. Training Requirements

Before the completion of power plant construction, training must be given to O &M Engineer. The training consists of theory, operation practice, and trouble shooting. GE as the technology supplier will conduct a comprehensive training program for a selected number of customer’s engineers, operations and maintenance personnel. Each participant of the training will be furnished a suitable bound course instruction and reference handbook in English.

V. Emergency preparedness and safety

The EPC contractor provided PT Bekasi Power with the Manual Safety Procedure in compliance with the relevant regulation. Emergency response procedures are developed for all potential incidents including fire, explosion, weather disturbances, lightning, etc. This procedure contains details on communication, fire fighting, medical, evacuation, resumption of operations and other details as maybe deemed required.

VI. Calibration of equipments

Calibration of natural gas flow meter and electricity meters has been detailed in the section B.7.1. of the PDD. As already mentioned above, the monitoring meters will be calibrated as per standard procedures at least once in a year to ensure accuracy.

Annex 5

LEAKAGE CALCULATIONS

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. Since the project activity does not use LNG, the leakage emissions are given as follows:

$$LE_y = LE_{CH4,y} \qquad (6)$$

Where:

$LE_{CH4,y}$	Leakage emissions due to fugitive upstream CH_4 emissions in the year y in tCO_2

$$LE_{CH4,y} = \lfloor FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4} \rfloor \cdot GWP_{CH4} \quad (7)$$

Where:

$LE_{CH4,y}$	Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_2e
FC_y	Quantity of natural gas combusted in the project plant during the year y in m³
NCV_y	Average net calorific value of the natural gas combusted during the year y in GJ/m³
$EF_{NG,upstream,CH4}$	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in t CH_4 per GJ fuel supplied to final consumers
$EG_{PJ,y}$	Electricity generation in the project plant during the year in MWh
$EF_{BL,upstream,CH4}$	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant, as defined below:
GWP_{CH4}	Global warming potential of methane valid for the relevant commitment period

Combined Margin

$$EF_{BL,upstream,CH4} = 0.5 \cdot \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j} + 0.5 \cdot \frac{\sum_i FF_{i,k} \cdot EF_{k,upstream,CH4}}{\sum_i EG_i} \quad (8)$$

Where:

$EF_{BL,upstream,CH4}$	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant
j	Plants included in the build margin

$FF_{j,k}$	Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin
$EF_{k,upstream,CH4}$	Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type) in t CH_4 per MJ fuel produced
EG_j	Electricity generation in the plant j included in the build margin in MWh/a
i	Plants included in the operating margin
$FF_{i,k}$	Quantity of fuel type k (a coal or oil type) combusted in power plant i included in the operating margin
EG_i	Electricity generation in the plant i included in the operating margin in MWh/a

Calculation of $EF_{BL,upstream,CH4}$ is shown in the table below:

Power Plant in Build Margin

Owner	Power Plant in Build Margin	Fuel Type	Quantity of fuel combusted (FFj,k)	unit	Quantity of fuel combusted (FFj,k)	unit	NVC		Emission factor for upstream fugitive methane emissions from production of the fuel (EFk,upstream, CH4)	unit	Electricity generation (Eg)(MWh)	(FFj,k)* (EFk,upstream, CH4)
							GJ/ k t fuel	GJ/ k ltr fuel				
			(1)				(2)		(3)		(4)	(1)* (3)
PT Paiton Energi	Paiton I	Steam-Coal	4,437	kton			24,030.8		0.8	tCH4/kton	9,116,000	3,549.9
PT Java Power	Paiton II	Steam-Coal	4,273	kton			24,030.8		0.8	tCH4/kton	9,109,000	3,418.4
Listrindo	Wayangwindu	Geothermal									922,000	-
Indonesia Ltd.	Darajad	Geothermal									735,000	-
PT Geo Dipa Energi	Dieng	Geothermal									319,000	-
PT Indonesia Power	Pemaron	GT-Oil	61,422	kltr				36.11	0.0000041	tCH4/GJ	201,325.5	9.1
Power	Cikarang	GT-Gas	4,070,300	MMBTU	4,294.57	TJ	48,000.0		0.296	tCH4/TJ	403,000	1,271.2
PT Krakatau Daya Listrik	Krakatau	Steam-Coal	0.836	kton			24,030.8		0.8	tCH4/kton	2,230	0.7
Muara Tawar	Block 3	GT-Oil	16,294,549	MMBTU	17,192.38	TJ	48,000.0		0.0041	tCH4/TJ	1,618,000	70.5
	Block 4	GT-Oil										
PT Sumberenergi Sakti Prima	Cilacap	Steam-Coal	764	kton			24,030.8		0.8	tCH4/kton	1,937,000	611.2
Tanjung Jati B	Tanjung Jati B	Steam-Coal	1,526	kton			24,030.8		0.8	tCH4/kton	3,869,000	1,220.9
Cilegon	Cilegon	CCGT-Gas	6,666,284	MMBTU	7,033.60	TJ	48,000.0		0.296	tCH4/TJ	742,000	2,081.9
Total											**28,973,555**	**12,233.82**

Total electricity generation in the plants included in the build margin (EG j) = 28,973,555 MWh

Power Plant in Operating Margin

Owner	Power Plant in Operating Margin	Fuel Type	Quantity of fuel combusted (FFj,k)	unit	Quantity of fuel combusted (FFj,k)	unit	NVC		factor for upstream fugitive methane emissions from production	unit	(FFj,k)* (EFk,upstream,CH4)
							GJ/ k t fuel	GJ/ k ltr fuel			
			(1)				(2)		(3)		(1)* (3)
IP	HSD	HSD	2,170,653	kilo litre			42,728.6	36.1	0.0000041	tCH4/GJ	321.329
IP	MFO	MFO	461,319	kilo litre			41,019.0	40.6	0.0000041	tCH4/GJ	76.808
IP	IDO	IDO	2,343	kilo litre			41961.0637	36.9257	0.0000041	tCH4/GJ	0.355
IP	Gas	Gas	48,298,358	MMBTU	50,959.60	TJ	48000		0.296	tCH4/TJ	0.296
IP	Coal	Coal	13,165	kton			24030.8		0.8	tCH4/kton	10531.818
PT PJB	HSD	HSD	1,450,468	kilo litre			42,728.6	36.1	0.0000041	tCH4/GJ	214.718
PT PJB	MFO	MFO	1,593,046	kilo litre			41,019.0	40.6	0.0000041	tCH4/GJ	265.236
PT PJB	Gas	Gas	71,160,078	MMBTU	75,081.00	TJ	48000		0.296	tCH4/TJ	22223.975
PT PJB	Coal	Coal	2,753	kton			24030.8		0.8	tCH4/kton	2202.207
Muara Tawar	Gas	Gas	16,294,549	MMBTU	17,192.38	TJ	48000		0.296	tCH4/TJ	5088.944
Tanjung Jati B	Coal	Coal	1,525	kton			24030.8		0.8	tCH4/kton	1220.224
Cilegon	Gas	Gas	4,420,921	MMBTU	4,664.51	TJ	48000		0.296	tCH4/TJ	1380.696
IPP	Jatiluhur	Hydro									
IPP	Dieng	Geothermal									
IPP	Salak 4,5,6	Geothermal									
IPP	Wayang Windu	Geothermal									
IPP	Drajat II	Geothermal									
IPP	Cikarang	gas	4,070,300	MMBTU	4,294.57	TJ	48000		0.296	tCH4/TJ	1271.194
IPP	Paiton I	Coal	4,437	kton			24030.8		0.8	tCH4/kton	3549.866
IPP	Paiton II	Coal	4,273	kton			24030.8		0.8	tCH4/kton	3418.414
IPP	Krakatau	Coal	0.836	kton			24030.8		0.8	tCH4/kton	0.669
IPP	Cilacap	Coal	764	kton			24030.8		0.8	tCH4/kton	611.243
Total											**52377.991**

Total electricity generation in the plants included in the operating margin (EG i) (MWh) = 100,014,611

$EF_{BL,upstream,CH4}$ (Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant)
= 0.5 *(12,233.82 tCH_4/28,973,555 MWh) + 0.5 * (52,377.99 tCH_4/100,014,611MWh)
= 0.000473 tCH_4/MWh

Calculation of Leakage emissions due to fugitive upstream CH_4 emissions ($LE_{CH4,y}$)in t CO_2e is shown in this table below:

Parameter	Unit	Symbol	Value/year
Quantity of natural gas combusted in the project plant	m^3	$FC_{NG,y}$	208,759,413
Net calorific value of natural gas	GJ/m^3	NCV_{NG}	0.0365
Emission factor for upstream fugitive methane emissions of natural gas	t CH_4 per GJ	$EF_{NG,upstream,CH4}$	0.000296
Electricity generation in the project plant during the year	MWh	$EG_{PJ,y}$	891,070
Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity	t CH_4 per MWh	$EF_{BL,upstream,CH4}$	0.000473
Global warming potential of methane		GWP_{CH4}	21

Leakage emissions due to fugitive upstream CH4 emissions = [(1)*(2)]-[(3)*(4)]*(5)	**t CO_2**	$LE_{CH4,y}$	**38,566**

Annex 6

BENCHMARK CALCULATION

The benchmark is based on the Investment Rate issued by Bank of Indonesia, which is the Central Bank of Republic of Indonesia. The average investment rate from April 2006 to March 2007 was 15.44%. It was the latest available data during time of investment decision.

End of Period	Investment Rate
2006	
April	15.90
May	15.89
June	15.94
July	15.91
August	15.85
September	15.66
October	15.54
November	15.38
December	15.10
2007	
January	14.85
February	14.71
March	14.53
Average	15.438
Annual Average Investment Lending Rate	
Benchmark	15.44
Source: http://www.bi.go.id/SDDS/series/inr/index_inr.htm	

Annex 7

Clarification on Natural gas availability

Sufficient availability of NG	Within the Country	Within the Region
Supply balance	Most of the Indonesian's natural gas reserves are located in East Kalimantan (Badak field), Papua, South Sumatra and Natuna (the largest field in Southeast Asia). These four major gas centres account for most of the country's proven reserves. There are smaller fields in offshore West Java, offshore East Java (Kangean Block), Central Sulawesi and North Sumatra (Arun field). At the end of 2009, Indonesian proven reserves of natural gas were estimated at 3,180 billion cubic metres[34] (bcm) (1.7% of world share), with probable reserves in excess of that. Of these reserves, annual production was 71.9 bcm[35] (approximately 2.3% of its proved reserves) In Indonesia, natural gas transmission and distribution activities are mainly carried out by the state-owned utility Perusahaan Gas Negara (PT PGN). The distribution network is divided into three geographical areas, each of which is managed by a Strategic Business Unit (SBU) for distribution SBU I, II and III. The project activity is located in West Java- Bekasi area, which is part of the SBU I[36].	Natural gas supplied to SBU I distribution area is sourced from several extraction wells in South Sumatra - most operated by Medco EP, ConocoPhillips, Pertamina EP and Pertamina Hulu. Together these wells account for annual production of 17.7 bcm[37] and proven reserves of 119.5 bcm[38]. Natural gas is compressed and transported from South Sumatra to West Java through two pipelines - SSWJ 1 (530 mmscfd or 5.5 bcm) and SSWJ 2 (440 mmscfd or 4.5 bcm) Thus the SBU I area has an annual distribution capacity of 970 mmscfd[39] (or 10.03 bcm) per year operated by PT PGN. In 2009, the above South Sumatra wells supplied a total of 5.63 bcm[40] to PT PGN, which is only 31.8% of their regional production (the remainder is exported). It is important to note that as demand does not equal total capacity, these distribution pipelines do not operate at full capacity (only 5.63 bcm per year usage compared to 10.03 bcm capacity).

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[34] Source: Report BP Statistic - 2010 - Natural Gas - Proved Reserves – Indonesia - page 22

[35] Source: Report BP Statistic - 2010 - Natural Gas – Production – Indonesia - page 24

[36] SBU I distribution area includes the districts of Palembang, Jakarta, Bogor, Banten, **Bekasi**, Karawang, and Cirebon Annual Report PT PGN - 2009 - page 18 (PDF document pages)

[37] Source: Refer to supporting document Bekasi - NG Availability - Data Indonesia.xls

[38] Source: Refer to supporting document Bekasi - NG Availability - Data Indonesia.xls and Annual Report PT PGN - 2009 - page 76

Demand balance	In 2009, Indonesian consumption[41] of natural gas was estimated at 36.6 bcm (approximately 1.2% of its national proven reserves and 51% of its national production).	In 2009, the total volume of gas consumed in SBU I was 561 mmscfd[42] (5.8 bcm). This regional demand represents only 32.8% of regional production and 4.9% of the regional proven reserves. In comparison the project activity, Bekasi Power, will consume 0.2 bcm per year (below 20 mmscfd). This represents: • 3.5% of regional demand (SBU I for 2009); • 2% of the pipelines' capacity; • 1.1% of regional production; and • 0.2% of the regional proven reserves.

Consistent data on natural gas availability has been applied to the most recent year available, year 2009, this is the most realistic, accurate and latest estimation for the reserves, production and consumption. However, for purpose of the analysis we also provided data from year 2007 and 2008.

BP Energy Statistic Report – 2008
http://www.google.com/url?sa=t&source=web&cd=1&ved=0CBYQFjAA&url=http%3A%2F%2Fwww.bp.com%2Fliveassets%2Fbp_internet%2Fglobalbp%2Fglobalbp_uk_english%2Freports_and_publications%2Fstatistical_energy_review_2008%2FSTAGING%2Flocal_assets%2Fdownloads%2Fspreadsheets%2Fstatistical_review_full_report_workbook_2008.xls&ei=gHPPTIqRO4KivgPCkJCRBg&usg=AFQjCNEwy_s256gTjHW31IVUYyZk_13t9Q

PT PGN Annual Report– 2007/08
http://www.pgn.co.id/ir_ar.php

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[39] Source: Refer to supporting document Bekasi - NG Availability - Data Indonesia.xls and Annual Report PT PGN - 2009 - page 75 (PDF document pages)

[40] Source: Refer to supporting document Bekasi - NG Availability - Data Indonesia.xls and Annual Report PT PGN - 2009 - page 69 (PDF document pages)

[41] Source: Report BP Statistic - 2010 - Natural Gas – Consumption – Indonesia - page 27

[42] Source: Annual Report PT PGN - 2009 - page 45 (PDF document pages)

Annex 8

Clarification on Input Value for LEGC

Coal fired power plant

Input parameter	Thermal efficiency
Input Value	33.2%
Suitability of assumptions	The figure for a coal fired power plant thermal efficiency has been calculated from the list of Indonesian coal power plants, operating in the JAMALI grid.
Source	DJLPE (Direktorat Jenderal Listrik dan Pemanfaatan Energi - Directorate General of Electricity and Energy Utilization)
Supporting document	Bekasi - Input Value - Coal fired PP - Thermal Efficiency – DJLPE Bekasi - Input Value - GHG_JAWABALI_2006_DJLPE

<table>
<tr><td>Input parameter</td><td>Coal Price</td></tr>
<tr><td>Input Value</td><td>54 US$/ton</td></tr>
<tr><td>Suitability of assumptions</td><td>The data on Coal price has been sourced from the Jakarta Stock Exchange Price of Coal in April 2007, with characteristics as follows:
<table>
<tr><td>Location</td><td>Kalimantan (Distance from Java is 1200km)</td></tr>
<tr><td>Coal Type</td><td>Other-Bituminous Coal - Net Calorific Value of 5,900 kcal per kg (eq to 25.8 GJ per ton[43])</td></tr>
<tr><td>Coal Price</td><td>Domestic price for this type of coal is Rp 345,000 per ton of coal (approx 37.6 USD[44] per ton).
However, project developer conservatively chooses to apply the export rate of 46 USD per ton, which normally applies to international deliveries.</td></tr>
</table>
Since the coal for exportation is quoted ‘’FOB’’ (Free On Board), an additional conservative input value for transportation has been included and assumed as 15% of the total price. Coal freight rate will therefore approximate 0.67 USD per ton, for every 100km.</td></tr>
<tr><td>Source</td><td>Report May 2007:Jakarta Stock Exchange</td></tr>
</table>

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[43] Source: 2006 IPCC Guidelines for National GHG Inv., vol, 2, Table 1.2, p.1.18 - Other-Bituminous Coal

[44] Applying specific conversion rate available at the time of the investment decision for the project activity - April 2007 - 9174.31 IDR/USD

Supporting document	Bekasi - Input Value - Coal fired PP - Coal Price - Jakarta Stock Exchange 2007 (page 10) Bekasi - Input Value - Coal fired PP - 2006 IPCC Guidelines for National GHG Inv., vol, 2, Table 1.2, p.1.18 - Other-Bituminous Coal Bekasi - Input Value - Coal fired PP - Conversion Rate 9174.31 IDR per USD - 12.03.07

<table>
<tr><td>Input parameter</td><td>Fuel price Escalation (Coal & Oil)</td></tr>
<tr><td>Input Value</td><td>1.5%</td></tr>
<tr><td>Suitability of assumptions</td><td>The figure for Fuel price escalation has been assumed based on discussion with energy specialist working as an advisor for the project owner. It is assumed that a reasonable annual escalation for price of coal and fuel oil is 1.5%.
Since the project activity fuel price escalation has been estimated in the feasibility study to 2.5% annually, we could assume the same. Compare to the figure stated in the financial analysis (1.5%), 2.5% is higher. The impact of this change on the fuel price escalation to the LEGC is shown below.
<table>
<tr><th>LEGC (in cts USD/kWh)</th><th>Before*</th><th>After**</th></tr>
<tr><td>Natural Gas</td><td>7.08</td><td>7.08</td></tr>
<tr><td>Coal</td><td>4.75</td><td>4.99</td></tr>
<tr><td>Fuel Oil</td><td>21.65</td><td>23.42</td></tr>
</table>
*/** Before and After represent the impact of the change
As can be seen this increased the fuel oil and coal LEGC, however the cost of electricity generation for the coal alternative remains cheaper than other alternatives (fuel oil and natural gas).</td></tr>
<tr><td>Source</td><td>Feasibility Study Report</td></tr>
<tr><td>Supporting document</td><td>Bekasi - Input Value - Fuel price escalation - Appendix 8.1</td></tr>
</table>

Input parameter	Operation & Maintenance - Coal fired power Plant
Input Value	0.400 USD/kWh
Suitability of assumptions	The data on the O&M Coal fired power plant has been sourced from the power plant operation experience from PT PLN (Persero) with Paiton 1 Coal fired power plant in Indonesia. The fixed O & M costs consist of 0.3 USD per kWh generated and the variable O & M cost is 0.1 USD per kWh, therefore a total of 0.4 USD per kWh
Source	O&M cost - PT PLN Persero - Page 2/16 – Paragraph 2
Supporting	Bekasi - Input Value - Coal fired PP - O&M cost - PT PLN Persero

document	

Input parameter	O&M Escalation (Coal & Oil)
Input Value	2.5%
Suitability of assumptions	The figure for O&M escalation has been sourced from the project activity feasibility study report. To be consistent with the project activity, the escalation applied is 2.5% annually.
Source	Feasibility Study Report
Supporting document	Bekasi - Input Value - Fuel price escalation - Appendix 8.1

Input parameter	EPC Contract Cost - Coal Power Plant Cost
Input Value	130 Million USD
Suitability of assumptions	The figure for a Coal Power Plant EPC Contract cost is based on PT PLN Persero announcement to develop 10,000 MW of coal fired power plants in Indonesia for a cost of 10 billion USD for (Crash program[45]), thus a cost ratio per MW installed is 1 Million USD. The input value for a 2x65MW coal power will therefore be 130 Million USD. An additional article ‘’Bangka Pos’’ from July 09 has estimated the same cost of 10 billion Rupiah per MW installed. (approximately the same with a conversion rate of 10,000 Rp/USD)
Source	Initial source: Article on PLN Persero Investment Additional source: Article on coal PP investment BangkaPos - July 09
Supporting document	Initial supporting document: Bekasi - Input Value - Coal fired PP - O&M cost - PT PLN Persero Additional supporting document: Bekasi - Input Value - Coal fired PP - Investment cost 2 - Article BangkaPos - July 09

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[45] Source: Article on Crash Program

Input parameters	1. VAT + Other taxes 2. Contingency cost 3. Insurance cost 4. Land acquisition cost 5. Development cost 6. Administration cost 7. Working capital, staff, training	
Input Value	**Coal fired PP** 1. 13,000,000 USD 2. 2,600,000 USD 3. 390,000 USD 4. 4,000,000 USD 5. 1,950,000 USD 6. 1,300,000 USD 7. 384,000 USD	**Fuel Oil fired PP** 1. 12,398,753 2. 2,479,751 3. 371,963 4. 4,000,000 5. 1,859,813 6. 1,239,875 7. 384,000
Suitability of assumptions	Those input parameters are not correlated to the type of power plant been developed and therefore has been assumed to be the same as the project activity: 1. VAT + Other taxes is 10% of the EPC contract cost 2. Contingency cost is 2% of the EPC contract cost 3. Insurance cost is 0.3% of the EPC contract cost 4. Land acquisition assumed as same size/value as the project activity 5. Development cost is 1,5% of the EPC contract cost 6. Administration cost is 1% of the EPC contract cost 7. Working Capital, Staff, Training assumed as same as the project activity	
Source	Feasibility Study Report - Project costs – Chapter VIII – Page 3 - Appendix 8.6	
Supporting document	Bekasi - Input Value - Investment costs - FSR Chapter VIII page 2-3	

Fuel Oil power plant

Input parameter	Thermal efficiency
Input Value	33.27%
Suitability of assumptions	The figure for fuel oil fired power plant thermal efficiency has been calculated from the list of Indonesian fuel oil power plants, operating in the JAMALI grid.
Source	DJLPE (Direktorat Jenderal Listrik dan Pemanfaatan Energi) - Directorate General of Electricity and Energy Utilization)
Supporting document	Bekasi - Input Value - Fuel Oil fired PP - Thermal Efficiency – DJLPE Bekasi - Input Value - GHG_JAWABALI_2006_DJLPE

Input parameter	Fuel oil price
Input Value	0.559 US$/liter
Suitability of	Data on fuel oil price has been sourced from the on Indonesian state-owned

<table>
<tr><td>assumptions</td><td>corporation for oil, PT Pertamina, with characteristics are as follows:
<table>
<tr><td>Fuel Oil Type</td><td>Diesel Oil Industry (Price Non PBBKB) - Region 1
Net Calorific Value of 36.1 GJ per kliter[46] this is equivalent to 42.728 TG/Gg, with a density of 845kg/m^3, This value is in the IPCC range of 41.4 to 43.3 TG/Gg[47].</td></tr>
<tr><td>Fuel Oil Price</td><td>Domestic price for this type of HSD is 5,126 IDR per liter (approx 0.559 US$ per liter[48]).</td></tr>
</table></td></tr>
<tr><td>Source</td><td>Pertamina fuel price - Fuel Type: Domestic Sale Price</td></tr>
<tr><td>Supporting document</td><td>Bekasi - Input Value - Fuel Oil fired PP - Fuel Oil NCV – DIJPE

Bekasi - Input Value - Fuel Oil fired PP - 2006 IPCC Guidelines for National GHG Inv., vol, 2, Table 1.2, p.1.18 – Diesel

Bekasi - Input Value - Fuel Oil fired PP - Fuel Oil Price Pertamina - April 2007</td></tr>
</table>

<table>
<tr><td>Input parameter</td><td>Operation & Maintenance - Fuel Oil fired power Plant</td></tr>
<tr><td>Input Value</td><td>0.320 USD/kWh</td></tr>
<tr><td>Suitability of assumptions</td><td>Data on Operation & Maintenance of a fuel oil fired power plant is difficult to access. It is generally considered that a coal fired power plant has the highest O&M cost of the proposed alternatives, and natural gas fired power plant the lowest. Therefore it has been estimated that the O&M for a fuel oil power plant would be the average of coal and gas - 0.320 USD per kWh.

An additional document ‘’Analisis Potensi Sumber Daya Energi’’ (Page 7 - Table 3 - PLTD[49]) has estimated the cost of fixed O&M at 5.5 USD/kWy and variable O&M at 2.17 USD/kWy giving a total O&M of 7.67 USD/kWy – approx 0.5113 USD/kWh

Compare to the figure stated in the financial analysis (0.320 USD/kWh), 0.5113 USD/kWh is higher (and is therefore less conservative). The impact of this change on the fuel oil O&M to the LEGC is shown below.
<table>
<tr><th>LEGC (in cts USD/kWh)</th><th>Before*</th><th>After**</th></tr>
<tr><td>Natural Gas</td><td>7.08</td><td>7.08</td></tr>
<tr><td>Coal</td><td>4.75</td><td>4.75</td></tr>
</table></td></tr>
</table>

---

[46] Source: Bekasi - Input Value - GHG_JAWABALI_2006_DJLPE (Direktorat Jenderal Listrik dan Pemanfaatan Energi - Directorate General of Electricity and Energy Utilization) – spreadsheet: Unit&SFC

[47] Source: 2006 IPCC Guidelines for National GHG Inv., vol, 2, Table 1.2, p.1.18 - Gas/Diesel Oil

[48] Applying specific conversion rate available at the time of the investment decision for the project activity - April 2007 - 9174.31 IDR/USD

[49] PLTD: states for ‘’Pembangkit Listrik Tenaga Diesel’’ which means in Bahasa Indonesia, Diesel power plant

<table>
<tr><td></td><td><table><tr><td>Fuel Oil</td><td>21.65</td><td>21.67</td></tr></table>*/** Before and After represent the impact of the change

As can be seen this marginally increased the fuel oil LEGC, demonstrating that the use of a figure of 0.320 USD/kWh is conservative.</td></tr>
<tr><td>Source</td><td>Initial source: calculated

Additional source:
Analisis Potensi Sumber Daya Energi - Page 7 - Table 3 - PLTD</td></tr>
<tr><td>Supporting document</td><td>Initial supporting document: Calculated

Additional supporting document:
Bekasi - Input Value - Fuel Oil fired PP - O&M cost - Analisis Potensi Sumber Daya Energi - Page 7 - Table 3 - PLTD</td></tr>
</table>

<table>
<tr><td>Input parameter</td><td>EPC Contract Cost - Fuel Oil Power Plant Cost</td></tr>
<tr><td>Input Value</td><td>123,987,526 USD</td></tr>
<tr><td>Suitability of assumptions</td><td>The figure for the fuel oil power plant EPC contract cost is based on an article from PT Wijaya Karya Tbk, that plan to investment an estimated to 350 Billion Rupiah in the installation of a 40 MW diesel fired power plant (PLTD) in Indonesia. This approximate an investment cost of 953,750 USD per MW installed[50]. The input value for a 2x65MW fuel oil power will therefore be 123,987,526 USD.

An additional article specify that the same fuel oil fired power plant in Bali will actually reach a capacity of 50MW for an estimated investment cost of 460 Million Rupiah, which is approximately 1,002,834 USD per MW installed[22].

Compare to the figure used in the financial analysis (953,750.2 USD per MW), 1,002,834 USD per MW is higher (and is therefore less conservative). The impact of this change to the fuel oil investment cost would be impacted on the LEGC as follows:

<table>
<tr><th>LEGC (in cts USD/kWh)</th><th>Before*</th><th>After**</th></tr>
<tr><td>Natural Gas</td><td>7.08</td><td>7.08</td></tr>
<tr><td>Coal</td><td>4.75</td><td>4.75</td></tr>
<tr><td>Fuel Oil</td><td>21.65</td><td>21.84</td></tr>
</table>
*/** Before and After represent the impact of the change

As can be seen this marginally increased the fuel oil LEGC, demonstrating that the use of a figure of 953,750.2 USD per MW is conservative.</td></tr>
<tr><td>Source</td><td>Initial source: Investment cost - Etradinggallery

Additional source: Investment cost - Bataviase</td></tr>
<tr><td>Supporting document</td><td>Initial supporting document:
Bekasi - Input Value - Fuel Oil fired PP - Investment cost - Etradinggallery

Additional supporting document:
Bekasi - Input Value - Fuel Oil fired PP - Investment cost - Bataviase</td></tr>
</table>

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[50] Applying specific conversion rate available at the time of the investment decision for the project activity - April 2007 - 9174.31 IDR/USD