Voluntary Carbon Standard
Project Description

Date of VCS PD: 09 November 2009
Version: 3

Table of Contents

1 Description of Project: 2
2 VCS Methodology: 9
3 Monitoring: 24
4 GHG Emission Reductions: 32
5 Environmental Impact: 40
6 Stakeholders comments: 41
7 Schedule: 41
8 Ownership: 42
9 Annex: 42

1 Description of Project:

1.1 Project title

210 MW Musi Hydro Power Plant, Bengkulu
Date: 09 November 2009
Version: 3

1.2 Type/Category of the project

The project activity is a new run-of-river type hydro power plant. Total installed capacity of the project is 210 MW, consisting of three (3) x 70 MW turbines. The project is owned and developed by PT. PLN (Persero), a state-owned electricity company. The project supplies electricity to the connected Sumatra grid. The electricity currently generated by the grid is relatively carbon intensive. The proposed project will increase the utilization of renewable energy sources, in this case hydro energy, by operating a new hydropower plant.

According to the CDM UNFCCC criteria, one approved GHG program by the Voluntary Carbon Standard (VCS) Board, the project is classified as large scale. Further to this, based on Annex A of the Kyoto Protocol it falls under the following types/categories of the Clean Development Mechanism under Kyoto Protocol:

- "Consolidated baseline methodology for grid-connected electricity generation from renewable sources"

Reference: Approved consolidated baseline methodology ACM0002/Version 10, Sectoral Scope: 1, EB 47

- The specified project is not a part of a grouped project.

1.3 Estimated amount of emission reductions over the crediting period including project size:

The project activity is a run-of-river type hydro power plant. Total installed capacity of the project is 210 MW, consisting of three (3) x 70 MW turbines. The 3 x 70 MW installed capacity generates an average of 847'020 emission reduction credits per year.

Based on the VCS Program Guidelines 2007.1, there are three project groups as follow:
- Micro projects: under 5,000 tCO_2-e per year
- Projects: 5,000 – 1,000,000 tCO_2-e per year
- Mega projects: greater than 1,000,000 tCO_2-e per year

The proposed project activity meets the requirement for the 'projects' group, generating emission reduction credits between 5,000 – 1,000,000 tCO_2e per year.

Emission reduction estimates over a crediting period of 10 (ten) years is provided in the table below:

Year	Vintage year	Annual Agreed Volume*
2006 – 2007	1 August 2006 – 31 July 2007	847,020
2007 – 2008	1 August 2007 – 31 July 2008	847,020
2008 – 2009	1 August 2008 – 31 July 2009	847,020
2009 – 2010	1 August 2009 – 31 July 2010	847,020
2010 – 2011	1 August 2010 – 31 July 2011	847,020

2011 – 2012	1 August 2011 – 31 July 2012	847,020
2012 – 2013	1 August 2012 – 31 July 2013	847,020
2013 – 2014	1 August 2013 – 31 July 2014	847,020
2014 – 2015	1 August 2014 – 31 July 2015	847,020
2015 – 2016	1 August 2015 – 31 July 2016	847,020
Total estimated reductions (tCO_2e)		8,470,020
Total number of crediting years		10 years
Annual average of the estimated reductions over the crediting period (tCO_2e)		847,020

*The ER calculation is based on designed annual electricity generation stated in Musi FS project report 1993.

1.4 A brief description of the project:

Indonesia has great potential for hydro energy resources that are not yet fully exploited. According to the national energy policy, the potential capacity of hydro resources in Indonesia is 75,000 MW. To date only 3,200 MW of this capacity has been generated (including captive power and private entities)[1].

The project is a new run-of river hydro power plant in Bengkulu Province in Indonesia. The project is owned and developed by PT. PLN (Persero), a state-owned electricity company.

The key purpose of the project is to utilise the hydrological resources of the Musi River, which is a renewable source of energy, to generate zero emission electricity to be transmitted to the Sumatra grid (hereafter referred to as the grid) through the Pekalongan PLN main station, with a 150 kV transmission line respectively. It will displace fossil fuel based power and reduce the emissions associated with fossil fuel based power plants on the Grid. Therefore, the project activity is reducing greenhouse gas emissions.

The total installed capacity of the project is 210 MW, consisting of three 70 MW turbines, with a designed load factor of 61.97%; all of the power generated will be delivered to the grid. The electricity currently generated by the grid is rather carbon intensive, with a grid emission factor (GEF) in 2008 of 0.743 tCO_2/MWh[2].

Following are operation dates of all three units:
Unit 1: 19 July 2006 (Commissioning Certificate- Laporan Inspeksi Uji Kelaikan Operasi)
Unit 2: 19 July 2006 (Commissioning Certificate- Laporan Inspeksi Uji Kelaikan Operasi)
Unit 3: 19 July 2006 (Commissioning Certificate- Laporan Inspeksi Uji Kelaikan Operasi)

1.5 Project location including geographic and physical information allowing the unique identification and delineation of the specific extent of the project:

The project area of the Musi Hydroelectric Power Plant is situated in Bengkulu Province about 30 km northeast of Bengkulu city, the capital of the Province. It involves the inter-basin transfer of water from the Musi river in Rejang Lebong Regency to the Simpangaur river in North Bengkulu Regency through a 7.5 km long waterway and an underground powerhouse.

[1] Indonesia Power Sector, EU-Indonesia Infrastructure Forum, November 2007.
www.eurocham.or.id/download.php?path=EUROCHAM_UPLOAD_DIR&cid=217&id=185

[2] http://dna-cdm.menlh.go.id/ Downloads/Others/Komnas MPB_Grid_Sumatera_JAMALI_2008.pdf

The location is 3°37' 6.59" S, 102° 27' 25.87" E.[2]

Source: Google Earth

Figure 1. Location of Musi Powerplant

1.6 Duration of the project activity/crediting period:

As per the VCS policy announcement from the 10 September 2008, the project start date is the date on which the project activity began reducing or removing GHG emissions. All three units of Musi started operation on the 19 July 2006 therefore the project start date is 19 July 2006.

Crediting period start date: 1 August 2006.

Crediting period: 10 years fixed crediting period from 1 August 2006 until 31 July 2016.

[2] Location of Musi regulating dam according to EIA page IV-2.

1.7 Conditions prior to project initiation:

The project is a Greenfield project.

1.8 A description of how the project will achieve GHG emission reductions and/or removal enhancements:

The project utilizes a run-of-river for generating electricity which otherwise would have been generated through power plants connected to the grid, that are mostly fossil fuel based power plants. Sumatra grid is operating with a mix hydro and fossil-fuel power plants.

The purpose of the project activity is to generate electricity using renewable hydro energy and sends it to the Sumatra grid. In the absence of the project activity, equivalent power would have been generated based on the fossil fuel intensive Sumatra grid resulting in Green House Gas emissions into the atmosphere.

1.9 Project technologies, products, services and the expected level of activity:

The Project is a new run-of-river type hydropower plant. Its main purpose is to generate electricity with a total installed capacity of 210 MW (consisting of 3 × 70 MW turbines). Annual energy output is expected at 1,140 GWh; harnessing a gross water head of 404.4 m by diverting water at 42.3 m^3/sec from the Musi river to the Simpangaur river, in an adjacent watershed, through a 7.5 km long waterway and an underground powerhouse.

The electricity production can be described as follows. Water is taken from the Musi river through the intake dam and then enters into the turbine through the high-pressure pipeline to produce electricity by driving the generators. The water then discharges into to the Simpangaur river through the tailrace.

The Project will use proven technology in electricity generation and transmission. The essential equipment used in the Project had to be procured from another country. Prior to the project commissioning the project developer organized a series of training sessions with the equipment supplier. The training conducted mainly covered the following topics: management of hydropower generation, operation and maintenance of a hydropower plant, operation and maintenance of a turbine, generator and other equipment. The purpose of the training was to enable the local staff to perform regular and safe operation and maintenance.

The main technical parameters of the proposed project are shown in table below:

Table 1 Main technical parameters of the proposed project

Parameter	Capacity	Source
Installed capacity (MW)	210	Musi FS Project Report 1993
Expected annual power generation (effective supply to the grid) (MWh)	1,140,000	Musi FS Project Report 1993
Water head (m)	404.4	Musi FS Project Report 1993
Design flow (m^3/s)	42.3 m^3/sec	Musi FS Project Report 1993
Load Factor (%)	61.97%	Calculated by dividing the expected annual power generation by the maximum annual electricity production. The maximum annual electricity production is calculated by multiplying the

		installed capacity with 8760 hours.

1.10 Compliance with relevant local laws and regulations related to the project:

The project meets all local laws and regulations of the government of Indonesia. The project activity, in using hydropower to generate electricity, is a voluntary action that has never been imposed by the Government of Indonesia.

The project has a land deed agreement, construction permit and an Environmental Impact Assessment.

1.11 Identification of risks that may substantially affect the project's GHG emission reductions or removal enhancements:

The hydro power plant is already commissioned and operating properly. The following are the risks that may substantially affect the project's GHG emissions reductions:

1. Supply of water
   The project is a run-off-river hydropower plant and operation of the project really depends on the water supply. Supply of water also depends not only on the season but also influenced by the change in climate and the soil capacity to absorb the rainwater.
2. Natural disaster
   The project activity is located in a geologically sensitive region (ring of fire) where frequent natural disaster such as earthquake occurs. Also deforestation and high level of rainfall in the area will cause floods.

3. Unexpected machine breakdown
   Even the project use proven technology, we have to consider unexpected machine breakdown.

1.12 Demonstration to confirm that the project was not implemented to create GHG emissions primarily for the purpose of its subsequent removal or destruction.

The hydropower project has been installed with the aim of harnessing the under-developed hydro potential of the region. The electricity generated from the project activity meets the power demand of the region. Hence, it is contributes greatly toward filling the gap of demand and supply in the Sumatra region.

Thus, it is evident that project proponent has initiated this project with an aim to supply electricity to the grid, and not primarily for creating GHG emissions primarily for the purpose of its subsequent removal.

1.13 Demonstration that the project has not created another form of environmental credit (for example renewable energy certificates).

The project activity has not applied for any other form of environmental credits. The official statement in the form of a letter of undertaking has been submitted to DOE.

1.14 Project rejected under other GHG programs (if applicable):

The project has not been rejected under any other GHG programs.

1.15 Project proponents roles and responsibilities, including contact information of the project proponent, other project participants:

Project proponents	Responsabilities
PT. PLN (Persero) (public entity)	Project owner and operator
South Pole Carbon Asset Management Ltd. (private entity)	Carbon credit buyer

Project proponents contact information as follows:

Project owner:

Organization:	PT. PLN (Persero)
Street/P.O.Box:	Jl. Trunojoyo blok M 1/135, Kebayoran Baru
Building:	
City:	Jakarta
State/Region:	
Postfix/ZIP:	12160
Country:	Indonesia
Telephone:	+62-21-725 1234
Fax:	+62 21 722 7026
E-Mail:	
URL:	www.pln.co.id
Represented by:	
Salutation:	Ms.
Last Name:	Semiawan
Middle Name:	
First Name:	Assistia
Mobile:	+62-811-962 833
Direct Fax:	+62 21 722 7026
Direct Tel:	+62-21 726 1122 ext. 1112
Personal E-Mail:	assistias@pln.co.id

Carbon credit buyer:

Organization:	South Pole Carbon Asset Management Ltd.
Street/P.O.Box:	Technoparkstrasse 1
Building:	
City:	Zurich
State/Region:	
Postfix/ZIP:	8005
Country:	Switzerland
Telephone:	+41-44 633 7870
Fax:	+41-44 633 1423
E-Mail:	info@southpolecarbon.com
URL:	www.southpolecarbon.com
Represented by:	
Salutation:	Mr.
Last Name:	Heuberger
Middle Name:	
First Name:	Renat
Mobile:	+41-79 549 3951

Direct Fax:	
Direct Tel:	
Personal E-Mail:	r.heuberger@southpolecarbon.com

1.16 Any information relevant for the eligibility of the project and quantification of emission reductions or removal enhancements, including legislative, technical, economic, sectoral, social, environmental, geographic, site-specific and temporal information.):

The project is contributing to sustainable development specifically defined by the Government of Indonesia as follows:

Social well-being:
- The project contributes to the development of the region by increasing community development and corporate social responsibility of PT. PLN (Persero).
- During both construction and operation, various kinds of mechanical work were required, providing opportunities for part-time and full-time employment.

Economic well-being:
- The project activity generates employment in the local area which is a developing region.
- The generated electricity is fed into regional grids through the local grid, thereby improving the grid frequency and availability of electricity to local consumers (villagers and sub-urban inhabitants). Due to increased grid reliability, new opportunities for industries and economic activities arise along with prospects for local employment and overall development.
- The project activity leads to diversification of the national energy supply, which is dominated by conventional fuel based generating units.
- The project activity contributes to the economic sustainability around the plant sites, which is encouraging economic power decentralization.

Environmental well-being:
- The project utilizes hydropower to generate electricity, which otherwise would have been generated through alternate fuel- (most likely fossil fuel-) based power plants. This contributes to a reduction in specific emissions (emissions of pollutant/unit of energy generated), including GHG emissions.
- As hydroelectric power projects do not produce end-products in the form of solid waste (ash, etc.), they do not have to cope with the problem of solid waste disposal encountered by most other sources of power.
- Being a renewable energy source, hydro energy is used to generate electricity that contributes to resource conservation.

Technological well-being:
- The project supports high quality equipments transfer from other regions and even other countries, and contributes to capacity building of the labor force through training and practical work.
- The project promotes local products developed in the region, when the replacement of parts is necessary, and supports renewable technology development especially for hydroelectric power technology.

In light of the above explanation, the project participants consider that the project activity profoundly contributes to sustainable development.

1.17 List of commercially sensitive information (if applicable):

All information provided in this project document and relevant supporting calculation sheets can be publicly published.

2 VCS Methodology:

2.1 Title and reference of the VCS methodology applied to the project activity and explanation of methodology choices:

The project primarily displaces power from the Sumatra grid. According to Annex A of the Kyoto Protocol, this project falls into Sectoral Scope 1 - Energy industries (renewable-/non-renewable sources).
The approved consolidated baseline methodology ACM0002, "Consolidated baseline methodology for grid connected electricity generation from renewable sources", version 10, in effect as of EB 47.

This methodology also refers to the latest approved versions of the following tools:

1. The approved "Tool for demonstration and assessment of additionality", version 05.2.
2. The approved "Tool to calculate the emission factor for an electricity system", version 02.
3. The approved "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion", version 02.

Project activity is not subject to any deviation or revision of methodology.

For more information regarding the proposals and their consideration by the Executive Board please refer to http://cdm.unfccc.int/methodologies/PAmethodologies/index.html.

2.2 Justification of the choice of the methodology and why it is applicable to the project activity:

Musi hydroelectric power plant (HEPP) is a new grid-connected run-of-river type hydropower plant. According to "Section I: Source, Definitions and Applicability of Approved consolidated baseline and monitoring methodology ACM0002 Version 10", the project activity is applicable under the following conditions:

Applicability Condition	Project Compliance	Information Source
Project activity is a grid-connected renewable power generation project activity that (a) installs a new power plant at a site where no renewable power plant was operated prior to the implementation of the project activity (greenfield plant); (b) involves a capacity addition; (c) involves a retrofit of (an) existing plant(s); or	Musi HEPP is a grid-connected run of river hydro power plant that (a) install a new power plant at a site where no renewable power plant was operated prior to the implementation of the project activity (greenfield plant); (b) does not involve a capacity addition; (c) does not involve a retrofit of an existing plant; or (d) does not involve a replacement of (an) existing plant.	PLN

[3] PLN Sumatra is a regional state owned electricity company in Sumatra

Applicability Condition	Project Compliance	Information Source
(d) involves a replacement of (an) existing plant(s)	Musi HEPP is connected with a regional power grid, the Sumatra grid; the Sumatra grid is clearly identified and information on the characteristics of this grid is publicly available from PLN Sumatra[3].	
The project activity is the installation, capacity addition, retrofit or replacement of a power plant/unit of one of the following types: hydro power plant/unit (either with a run-of-river reservoir or an accumulation reservoir), wind power plant/unit, geothermal power plant/unit, solar power plant/unit, wave power plant/unit or tidal power plant/unit.	Musi HEPP, the project activity, is the installation of a new run-of-river hydro power plant, one of the following types: hydro power plant/unit (either with a run-of-river reservoir or an accumulation reservoir), wind power plant/unit, geothermal power plant/unit, solar power plant/unit, wave power plant/unit or tidal power plant/unit;	PLN
In the case of capacity additions, retrofits or replacements: the existing plant started commercial operation prior to the start of a minimum historical reference period of five years, used for the calculation of baseline emissions and defined in the baseline emission section, and no capacity expansion or retrofit of the plant has been undertaken between the start of this minimum historical reference period and the implementation of the project activity.	There is no capacity additions, retrofits or replacements for the Musi HEPP. Project activity is a new grid connected run-of-river hydro power plant. There is no existing reservoir prior to the project activity.	PLN
In case of hydro power plants, one of the following conditions must apply: • the project activity is implemented in an existing reservoir, with no change in the volume of reservoir; or • the project activity is implemented in an existing reservoir, where the volume of reservoir is increased and the power density of the project activity, as per definitions given in the Project Emissions section, is greater than 4 W/m_2; or • the project activity results in new reservoirs and the power density of the power plant, as per definitions given in the Project Emissions section, is greater than 4 W/m^2.	Musi HEPP is a run-of-river hydro power plant where there is no existing reservoir prior to the project activity (Greenfield project). Therefore the following conditions are not applicable: • The project activity is not implemented in an existing reservoir since it is a greenfield project; and • The project activity does not result in new reservoirs.	PLN
Project activities does not involve switching from fossil fuels to renewable energy sources at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels	Musi HEPP does not involve fossil fuels switching to renewable energy.	PLN

Applicability Condition	Project Compliance	Information Source
at the site.		
Project activity is not a biomass fired power plants.	Musi HEPP is a run-of-river hydro power plant.	PLN
Hydro power plants that result in new reservoirs or in the increase in existing reservoirs where the power density of the power plant is less than 4 W/m^2.	Musi HEPP is implemented as a run-of-river project. There is no existing reservoir prior to the project activity.	PLN

The applicability criteria stated in methodology ACM0002 (Version 10) are met on the basis of the reasons above.

2.3 Identifying GHG sources, sinks and reservoirs for the baseline scenario and for the project:

	Source	Gas	Included?	Justification / Explanation
Baseline	CO_2 emissions from electricity generation in fossil fuel fired power plants that re displaced due the project activity.	CO_2	Yes	Main emission source. CO_2 emissions from grid electricity production.
		CH_4	No	Minor emission source
		N_2O	No	Minor emission source
Project Activity	For hydro power plants, emissions of CH_4 from the reservoir.	CO_2	No	Minor emission source
		CH_4	No	Not applicable since the project is a run-of-river hydropower plant that does not result in new reservoir
		N_2O	No	Minor emission source

2.4 Description of how the baseline scenario is identified and description of the identified baseline scenario:

As per the approved consolidated methodology ACM0002, version 10, since the project activity involves the installation of a new grid-connected hydro power plant, the baseline scenario is the following:

Electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources as reflected in the combined margin (CM) calculations described in the "Tool to calculate the emission factor for an electricity system".

The project activity uses the "BASELINE METHODOLOGY PROCEDURE" as described in the applied methodology.

Identification of the baseline scenario

As per the methodology, if the project activity is the installation of a new grid-connected renewable power plant/unit, the baseline scenario is electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations described in the "Tool to calculate the emission factor for an electricity system".

Since the project activity is the installation of a new grid-connected hydroelectric power plant hence the baseline scenario is the same as described above. Combined Margin for the grid has been calculated as per "Tool to calculate the emission factor for an electricity system".

Electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as is reflected in the combined margin (CM) calculations described in the "Tool to calculate the emission factor for an electricity system".

2.5 Description of how the emissions of GHG by source in baseline scenario are reduced below those that would have occurred in the absence of the project activity (assessment and demonstration of additionality):

As per ACM002 version 10, the additionality of the project activity shall be demonstrated and assessed using the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the CDM Executive Board.

The following steps are used to demonstrate the additionality of the project according to the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the Executive Board (version 05.2, EB 39).

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

The baseline is defined for a Greenfield project as per methodology as "Electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition for new generation sources, as reflected in the combined margin (CM) calculations described in the "Tool to calculate the emission factor for an electricity system"". Therefore according to the Validation and Verification manual, no further analysis is required.

Step 2. Investment Analysis

Sub-step 2a: Determine appropriate analysis method

According to the "Tool for the demonstration and assessment of additionality (version 05.2)", three options can be applied to conduct the investment analysis. These are: the simple cost analysis (Option I), the investment comparison analysis (Option II) and the benchmark analysis (Option III).

Since this project will generate financial/economic benefits other than VCS-related income, through the sale of generated electricity, Option I (Simple Cost Analysis) is not applicable.

There were no other alternatives considered of designing the project activity. Hence, option II the investment comparison analysis is not relevant and not applicable.

According to the Additionality Tool, either Option II or Option III can be chosen in the context of the project activity. Given that the baseline is the continuation of supply of electricity from the grid and not an alternative power plant with similar output, benchmark analysis (Option III) is then used for assessing the financial attractiveness of the project activity most accurately.

Sub-step 2b: Option III – Application of benchmark analysis

The likelihood of the development and further operation of this project, as opposed to the continuation of the purchase of grid electricity from the current electricity generation mix (i.e. its baseline) will be determined by comparing the project IRR (without carbon benefits) with benchmark rates available to a local investor. These could be provided by local banks, or investment bonds in the host country or it could be internally calculated, based on accepted models such as below. Method used for calculating the benchmark is WACC (weighted average cost of capital) whereas the cost of each type of capital financing the project is either given or calculated. Then these costs are averaged. The benchmark incorporates also lending rate as part of WACC calculation. WACC calculation is chosen as the appropriate benchmark since the Capital employed in financing the project consists of loan and Government's equity. Basically, the project needed loan from foreign institution not only to complement the government's equity to finance the project, to reduce the investment risk, and to increase the economic attractiveness of the project.

Table 2 – Parameter used for the Weighted Average Cost of Capital (WACC) calculation

Parameters	Value	Description	Source
Risk free rate	6.52%	30-year US Treasury Bill, average value in 30 June and 30 December 1993	US Department of the Treasury[4]
Beta	0.83	Prof. Damodaran, Average beta for electricity-generation, in 2003.	Prof. Aswath Damodaran[5]
Premium risk	13.33%	Using total Indonesia risk premium by utilizing the data from 2000 to 2005. From this data, the premium risk of period 1992 to 1996 is calculated.	Prof. Aswath Damodaran[6] Interest parity is used to find the equivalent total Indonesia risk premium in year 1992 to 1996, based on inflation.[7]
Cost of debt	6.63% in USD 13.59% in IDR equivalent	Actual interest lending rate which has been converted from USD loan interest rate to IDR loan interest equivalent	% in USD is calculated using the loan interest stated in Musi FS Project Report 1993. % in IDR is calculated using Fisher model of interest rate parity (see below for

[4] http://www.ustreas.gov/offices/domestic-finance/debt-management/interest-rate/yield_historical_main.shtml

[5] Dr. Aswath Damodaran is a Professor of Finance at the Stern School of Business at New York University. He is best known as the author of several widely used academic and practitioner texts on Valuation, Corporate Finance, and Investment Management. http://pages.stern.nyu.edu/~adamodar/

[6] Dr. Aswath Damodaran is a Professor of Finance at the Stern School of Business at New York University. He is best known as the author of several widely used academic and practitioner texts on Valuation, Corporate Finance, and Investment Management. http://pages.stern.nyu.edu/~adamodar/

[7] *Global Finance*. Maximo V.Eng, Francis A. Less, Laurence J. Mauer. HarperCollins College Publisher. 1995. Page 106-113.

			explanation)
Cost of Equity	17.57%	Calculated using CAPM (see below)	Valuation book by Damodaran[8] and McKinsey & Co
Tax	30%	Income tax for calculating the WACC and also used in the cash flow	Tax Regulation UU no 17 year 2000[9]
Debt Amount	204,397,000 USD 1,366,789,368,532 IDR eq	Investment part which is debt	USD value: Musi FS Project report 1993; IDR equivalent: calculated using Foreign Currency Investment Disbursement 1994-2001 and USD/IDR Exchange Rate in 1994-2001
Equity Amount	137,613,000 USD 787,011,882,478 IDR equivalent	Investment part which is equity	USD value: Musi HEPP Project Report 1993;
USD/IDR Exchange Rate	2'112.46	USD/IDR Exchange Rate in 1993	International Trade Administration USA[10]

Model for calculating benchmark

The applied benchmark is determined by using the WACC model since the capital financing of the project is a mix of both equity and debt. Based on information submitted by PLN (project report and other sources), the project cost in USD currency is financed by a loan from the Asian Development Bank with an interest rate of 6.63% in a USD denomination. Debt/equity ratio of the project activity is 1.49 times. Equity financing is supported by the government of Indonesia in the form of an APBN (*Anggaran Perencanaan Belanja Negara*). In order to be able to calculte the WACC, the cost of debt and the burden of equity or investor's expected return in equity should be calculated first.

1. *Calculate IDR equivalent cost of debt using Interest Rate Parity (Fisher model) and Purchasing Power Parity model*

Since the revenues of the project activity are based on IDR and investments are in USD, the project is exposed to currency risk towards USD denomination by carrying USD financing. When an obligation is dominated in a foreign currency, in this case USD currency, the loan interest rate in USD will be inappropriate when directly inserted to the above WACC formula, due to the foreign exchange exposure inherent in the financing. The exchange rate exposure is comprised as follow:

1. The revenue generated is in IDR currency and the obligation to pay the debt is in USD currency. If IDR is depreciated against USD, it will have a direct impact on PLN's ability in servicing its debt[11]. Such an impact is accounted for by applying the fisher model, elaborated below.
2. The project's location, Indonesia, implies additional risks such as political, economic, business risk (supply and demand risk) and the risk of natural disasters, etc. Such adverse

---

[8] *Damodaran on Valuation*. Aswath Damodaran. Wiley Frontiers. Page 20-42.

[9] www.pajak.go.id, *Undang-undang nomor 17, tahun 2000*

[10] http://ia.ita.doc.gov/exchange/indonesia.txt

[11] *Valuation: Measuring and Managing The Value of Companies.* Copeland, Tom; Koller, Tim; Murrin, Jack; McKinsey & Company. 2nd edition. 1994. page 262-263.

circumstances have an impact on local currency pricing and thus possibly affecting revenue as they often correlate directly to inflation and currency figuresl.[12] Such an impact is accounted for by applying the fisher model, elaborated below.

Thus, for comparison, the USD loan interest rate should be converted into the IDR interest rate equivalent first, by utilizing the interest rate parity model by Fisher[13,14] as shown below. The loan interest rate will be used to calculate the cost of the debt in order to determine WACC. The loan interest rate differential obtained represents the currency risk exposure that is to be included in determining the benchmark indicator or the reserve margin (hedging) against the USD/IDR currency exchange rate to which the project's expected IRR should cover. Usually, the all-in lending rate in foreign currency will be close to the cost of borrowing on domestic markets due to the interest-rate parity relationship.[15]

$$S_{t+1} = S_t \times \frac{1+\inf_{IDR}}{1+\inf_{USD}}$$

Fisher 1) [16,17]

$$S_{t+1} = S_t \times \frac{1+CD_{IDR}}{1+CD_{USD}}$$

Fisher 2)

$$\hat{S} = \hat{P}_{USD} - \hat{P}_{IDR}$$

Fisher 3)

Parameters	Description	Value	Base
S_t	USD/IDR Spot Rate	2'112.46	USD/IDR exchange rate in 1993
S_{t+1}	1-year USD/IDR Future Spot Rate	Calculated	
$\inf_{IDR}$	IDR inflation rate	9.69%	IDR Inflation Rate in 1993[18]
$\inf_{USD}$	USD inflation rate	2.97%	US inflation rate in 1993
CD_{USD}	USD cost of debt	6.63%	Loan interest and capital payment disbursement
CD_{IDR}	IDR equivalent cost of debt	Calculated	
S	Percent change in USD price to IDR		
P_{USD}	Percent change in price level in USA		

[12] Asian Development Bank report July 2003, *Impact evaluation study of Asian Development Bank Assistance to the power sector in Indonesia*, page 19-21.

[13] *Global Finance*. Maximo V.Eng, Francis A. Less, Laurence J. Mauer. HarperCollins College Publisher. 1995. Page 106-113.

[14] *Valuation: Measuring and Managing The Value of Companies.* Copeland, Tom; Koller, Tim; Murrin, Jack; McKinsey & Company. 2nd edition. 1994. page 262-264.

[15] *Valuation: Measuring and Managing The Value of Companies.* Copeland, Tom; Koller, Tim; Murrin, Jack; McKinsey & Company. 2nd edition. 1994. page 262-264.

[16] *Global Finance*. Maximo V.Eng, Francis A. Less, Laurence J. Mauer. HarperCollins College Publisher. 1995. Page 106-113.

[17] *Valuation: Measuring and Managing The Value of Companies.* Copeland, Tom; Koller, Tim; Murrin, Jack; McKinsey & Company. 2nd edition. 1994. page 262-264.

[18] International Monetary Fund, 2008 World Economic Outlook, http://www.indexmundi.com/indonesia/inflation_rate_ (consumer_prices).html

P_{IDR}	Percent change in price level in Indonesia

The model explains how spot exchange rates are sensitive to changes in inflation. It defines the equilibrium between present and future spot rates and the differences in interest rates between two countries. The exchange rate adjustment will be equal and opposite to the interest rate differential. The spot rate must change to offset differential rates of inflation in the two countries compared. There are 2 steps to determine the IDR equivalent for the USD cost of debt.

a. First step: Determine the 1-year USD/IDR Future Spot Rate
   Using formula Fisher 1) and the data below, the 1-year USD/IDR Future Spot Rate results in 2'250.28

Parameters	Value	Base
S_{t+1}	2'250.28	Calculated
S_t	2'112.46	USD/IDR exchange rate in 1993, when the project was initiated.
inf_{IDR}	9.69%	IDR Inflation Rate in 1993
inf_{USD}	2.97%	US inflation rate in 1993

b. Second step: Determine the IDR-equivalent cost of debt
   Using the formula of Fisher 2) and the data below the IDR equivalent cost of debt results in 13.59%. Compared to the actual 15.95% domestic investment credit rate in 1993[19], the calculated IDR equivalent cost of debt is found to be conservatively lower. The original PLN USD cost of debt is 6.63%. By using this number the IDR interest equivalent would be 13.59%.

Parameters	Value	Base
CD_{IDR}	12.78%	Calculated
CD_{USD}	6.63%	Loan interest and capital payment disbursement
S_{t+1}	2'250.28	Calculated from Fisher 1)
S_t	2'112.46	USD/IDR exchange rate in 1993

2. *Calculate cost of equity using Capital Asset Pricing Model (CAPM)*

To calculate the Cost of Equity, there are two models to be explained below:

First Model:

CAPM = Capital Asset Pricing Model
*CAPM = Domestic Risk Free Rate + beta * (Domestic market return – Domestic Risk Free Rate)*

CAPM measures risk in terms of non-diversifiable variance and relates returns to the specified risk measure. It produces the minimum expected rate of return on equity investment for the particular project. The risk premium used in the CAPM is generally based upon historical data, and the premium is defined to be the difference between average returns on stocks and average returns on risk free securities in a mature equity market over the measurement period.

[19] *Coping with capital flows in East Asia,* Kwan, C.H.; Donna Vandenbrink; Siow Yue Chia; Nomura Soogoo Kenkyuujoo, Institut of South East Asian Studies and Nomura Research Institute, 1998, page 253 Table 10.4. Accessed at: http://books.google.com/books?id=fTbRlHrA3igC&dq=Coping+with+capital+flows+in+East+Asia&printsec=frontcover&source=bl&ots=CGttDo7wDm&sig=_a4r0_17WMglyA0EvmWd9qizvnM&hl=en&ei=UBz6SumkMJiG6wOO273rDA&sa=X&oi=book_result&ct=result&resnum=1&ved=0CAoQ6AEwAA#v=onepage&q=&f=false.

William Sharpe (1964) published the capital asset pricing model (CAPM). Treynor (1961) and Lintner (1965) also performed parallel work. CAPM extended Harry Markowitz's portfolio theory to introduce the notions of systematic and specific risk. For his work on CAPM, Sharpe shared the 1990 Nobel Prize in Economics with Harry Markowitz and Merton Miller.

This model is the most common model applied in capital market practice. It utilizes the domestic market return to find the additional risk premium over the risk free rate when investing equity in projects. In 1993, the Indonesian capital market was immature and in a state of development thus information for market return in 1993 is unattainable. Therefore, this model is not possible to be applied in this project activity.

Second Model:

*Expected Cost of Equity = Risk free Rate + beta *(Equity Market Risk + Country Risk)*[20]

Above model is issued by Prof Aswath Damodaran.

This second model is applying the US risk free rate and the US market return as the normal basis return that investors around the world would expect when investing in a particular country. To cover the currency exposure when investing in countries other than the US, the model applies country risk premium as rate adjustment.

Parameter	Value	Source
Risk free rate	6.52%	30-year US Treasury Bill, average value in 30 June and 30 December 1993.
Beta	0.83	Prof. Damodaran, Average Beta for Electric-generation in 2003 (the most closest data avalaible to the investmento decision in 1993; according to Prof. Damodaran.[21]
Equity market risk + country risk	13.33%	Total risk premium Indonesian average for1992 – 1996, calculated using Interest Rate Parity Fisher model, based on inflation during the period 1992-1996 and 2000 – 2005 and the total risk premium for Indonesia during the period 2000-2005. See calculation below.
Expected Cost of Equity	17.57	Calculated. Cost for investing in Equity.

The risk free rate used in this model is US risk free rate as US financial market and capital market are assumed to be the most mature financial market in the world. Since the Indonesian country risk for 1993 is unavailable, the risk premium is then calculated using the Fisher model. The risk premium for 1993 is taken as the average risk premium between 1992 and 1996. In comparison, average inflation data in Indonesia in 1992 to 1996 and 2000 to 2005 are used. Below is the

[20] Prof. Aswath Damodaran http://pages.stern.nyu.edu/~adamodar/pdfiles/papers/riskprem.pdf

[21] Source: 5 January 2009, Levered and Unlevered Betas by Industry, Emerging Markets, http://pages.stern.nyu.edu/~adamodar/

equation used to calculate the average risk premium during the period 1992 to 1996 using the Fisher model 1):

$$\frac{1+ECR_{92-96}}{1+ECR_{00-05}} = \frac{1+\inf_{92-96}}{1+\inf_{00-05}}$$

Parameters	Description	Value	Source
ECR_{92-96}	Average total risk premium Indonesia in 1992 - 1996	13.33%	Calculated
ECR_{00-05}	Average total risk premium Indonesia in 2000 - 2005	13.29%	Prof. Aswath Damodaran
Inf_{92-96}	IDR average inflation rate in 1992 - 1996	8.43%	International Monetary Fund, 2008 World Economic Outlook
Inf_{00-05}	IDR average inflation rate in 2000 - 2005	8.39%	International Monetary Fund, 2008 World Economic Outlook

Hence, the minimum cost of equity for the project is expected to be 17.57% in order to categorize the project as financially attractive by an equity investor.

The data to produce the cost of equity utilizes the information from the year 2000 until 2005, as it is defined as being under economic normal conditions. Such a condition definition is determined based on the average actual inflation during the period. The average is then compared with the inflation average during the years 1993 to 1996. If the average differential between two periods is insubstantial, the condition could be defined as similar. After comparison, the interest rate parity model (see below section) is then applied to determine out the equivalent total risk premium for Indonesia during the period 1993 to 1996. The risk premium equivalent results in 13.33% for the period1993 to 1996.

3. *Calculate WACC* (Weighted Average Cost of Capital) as benchmark IRR

$$WACC = \frac{CD \times Debt \times (1 - Tax) + CE \times Equity}{Debt + Equity}$$

Parameters	Description	Value	Source
WACC	Weighted Average Cost of Capital	12.75%	Calculated
CD	IDR equivalent cost of debt	13.59%	Calculated
Debt	Amount of debt	204,397,000 USD	See Table 2
Tax	Taxation value	30%	See Table 2
CE	Cost of equity	17.57%	See Table 2
Equity	Amount of equity	137,613,000 USD	See Table 2

The WACC is defined as the weighted average of the costs of the different components of financing used by the firm. With Cost of Equity of 17.57% and IDR equivalent Cost of Debt of 13.59%, WACC is found to be 12.75 %. While Project IRR is 5.77%, hence the project return is far below the benchmark indicator.

Lending to PLN comprises of some considerably high investment risks. Besides the pre-mentioned risks in building the project, the firm's unstable balance sheet raises concern and a potential risk that needs to be considered when determining the appropriate benchmark indicator. Based on the Impact Evaluation Study report by ADB, PLN's financial performance – was unsatisfactory throughout the 1980s mainly due to low operating efficiency, inadequate tariffs, and a high share of socially oriented events. PLN turned profitable in 1990. The government of Indonesia was reluctant to substantially increase the electricity tariff rate to achieve the target of the financial covenant stipulated in the loan agreement. Hence, the debt-service coverage ratio of the loans from ADB, of not less than 1.5 times, was complied with in most years except 1987 and 1988. The stipulated self-financing ratio of not less than 30% of capital expenditure was complied with only in 1995 and 2001, and the covenanted 8% of return on net fixed assets was never achieved because of PLN's poor financial performance.

On the whole, while the efforts of ADB and the World Bank attempted to enable PLN to achieve the stipulated financial targets through the use of covenants and policy, dialogue with the government was unsuccessful. It is a logical consequence that ADB did not provide any new project loans to the Indonesian power sector between 1996 and 2001, partly because of the government's reluctance to approve tariffs to an adequate level to cover costs of supply. Following the onset of the Asian financial crisis, the Indonesian Rupiah depreciated more than fourfold before stabilizing again. This had an immediate adverse impact on PLN's profitability given that more than 70% of its expenses and all PPAs(Power Purchase Agreement between PLN and Independent Power Producer who built power plant and sell the electricity to PLN) were dollar-denominated. Tariff levels in real terms began to deteriorate in 1994 and were improved after 2000 following the introduction of quarterly increases that were intended to enable PLN to achieve its covenanted rate of return. Field investigations and surveys reported that there was ample evidence of a reduction in the quality of PLN's services as its financial health deteriorated after the financial crisis.[22]

In PLN's 2002 annual report it is was stated that "The financial condition of PLN was classified as unhealthy due to an operational loss that reached Rp 8,162 Billion. Although the Basic Electricity Rate for 2002 had already been approved, the average sale price that reached Rp 448.03/kWh was still below the cost for production or below its economic value". Within the period of 1999 to 2000, the annual reports display PLN's poor financial performance. Earning of fixed assets were mostly negative due to loss of operating profit during low profit period, while the above ADB covenant required at least 8% return. This also leads to a negative rentability ratio (profit per total asset average) and return on investment ratio for most of the periods. Liquidity ratios were predominantly below 1, showing the inability of the company to perform standby liquidity in the event that the loans mature. Debt to equity ratios for most of the periods are about 3 to 4 times, especially within the year of 1999 where PLN experienced a significant loss from its operation. But in 2002, the report has shown a sharp escalation of equity due to the asset reevaluation as opposed to profit creation.[23]

In conclusion, it can be summarized that:

During the period of submitting the loan proposals to ADB/World bank/other G to G financier, PLN had constructed a tariff proposal which aimed to comply with the various financial ratios stipulated under the loans of ADB and the World banks. Unfortunately, the tariff target as proposed never materialized. During the period of 1991 to 2000, the tariff was never increased by more than 5% due to the Government's reluctance to approve tariffs that adequately covered the cost of supply.[24] VCS will be important in order to compensate for reduced revenue due to the shortfall in the increase in electricity tariffs.

PLN's operational performance in the early 1980s was generally unsatisfactory, characterized by low system load factors, excessive losses, and low sales per consumer and per employee. One of the factors was an unfavourable consumption structure and load demand profile, which limited the leverage available to PLN to draw profitable revenues from industrial consumers (over 70% of

[22] Asian Development Bank report July 2003, *Impact evaluation study of Asian Development Bank Assistance to the power sector in Indonesia*, page 19-21.

[23] PLN Annual Report year 2002.

[24] Asian Development Bank report July 2003, *Impact evaluation study of Asian Development Bank Assistance to the power sector in Indonesia*, page 19, paragraph 56, 57, page 43 (for tariff) and page 17-18 par 53

PLN's total consumers were small residential and commercial consumers using electricity primarily for lighting only).

In conclusion, it can be summarized that:

1. PLN did not meet its financial ratios stipulated in the ADB loan covenant primarily due to the government's reluctance to adequately increase the tariff in order to meet target covenanted ratios.
2. The Asian and domestic financial crisis, during 1998 and 1999, had a severe influence in the deterioration of PLN's balance sheet despite subsequent improvement.
3. VCS revenue would help to achieve a more sound financial position. VCS revenue would assist PLN in meeting all the stipulated financial targets in the ADB loan covenant.
4. VCS revenue would help to develop the surrounding water catchment area by means of reforestation.

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

The table below shows the financial analysis for the project activity without carbon finance. As shown, the project IRR (without carbon: 5.77 %) is lower than the benchmark rate of return applicable which is 12.75%, calculated with the formula above and supported by other investment risk outlined above. Thus, VERs are going to be important to alleviate the infeasible IRR and help the project to become more attractive.

Calculation of the IRR and NPV is based on the annual cash flow, which considers the annual revenue of produced electricity, yearly operating cost, and investment cost.
Items to be considered in cash flow:

- Revenue
- Operating cost and maintenance
- Tax
- Depreciation (to calculate tax, but added back and therefore not affecting cash flow)

Cash flow is calculated as follows[25]:

Revenue – operating expenses
= Earnings before interest, taxes and depreciation (EBITDA) – Depreciation and amortization
= Earnings before interest and taxes (EBIT) – Taxes
= Net income + depreciation and amortization
= Cash flows from operations – capital expenditures – working capital needs
= Free Cash Flow

Cash Flow is calculated under IDR denomination currency since:

1. The project is located in Indonesia; the appropriate associated risks are Indonesian country risks and market risks as is utilized in the WACC calculation. All risks, such as natural disaster risk, political stability risk, economy risk, currency risk, etc. have a particular likelihood in Indonesia and would have a direct impact on the survival of the project; ergo, presenting cash flow in the domestic currency is more appropriate.
2. The revenue is in Indonesian currency.
3. Operating and Maintenance cost is dominated in IDR.

Table 3 Summary of project financial analysis (without carbon finance)

	With VCS
IRR	5.77%
Applicable Benchmark	12.75%

[25] Damodaran on Valuation by Aswath Damodaran page 20-42 published by Wiley Frontiers in Finance

The parameters presented in Table 4 have been used to conduct the financial analysis.

Table 4 Economic parameters used in the project

Name	Value	Source
Installed capacity (MW)	210 (3 × 70)	Musi FS Project Report 1993
Output capacity (MWh/year)	1,140,000	Musi FS Project Report 1993
Income tax (%)	30%	Government policy[26]
Project cash flow (Year)	30	
Tariff for PLN, excluding VAT (IDR/kWh)	129.05	Musi FS Project Report 1993
Total investment (USD)	342,010,000	Musi FS Project Report 1993
Operation & Maintenance costs (USD/year)	3,440,000	Musi FS Project Report 1993

Sub-step 2d: Sensitivity analysis

A sensitivity analysis has been performed to determine in which scenarios the project activity would overtake the benchmark, indicating its viability. The project viability is evaluated through the increment + or - 10% of the following parameters: (1) project revenue (electricity tariff or electricity generation); (2) total investment, (3) operational cost.

Table 5 summarizes the results of the sensitivity analysis.

Table 5 Different parameters affecting the project's IRR

Scenario	% change	IRR (%)
Original		5.77%
Increase in Tariff	10%	6.57%
Reduction in Investment Costs	10%	6.58%
Reduction in Operational Costs	10%	6.00%

These results show a reasonable range of fluctuation by the four parameters, the IRR of the proposed project is still lower than the benchmark, which obviously demonstrates that the proposed project will reach financial attractiveness varying crucial parameters within a realistic range.

As a comparison the same four parameters have been adjusted in Table 6 until the benchmark is hit to elaborate the robustness of the IRR calculation.

Table 6 Different parameters to hit benchmark

[26] Indonesian Government (1994), Perubahan Atas UU no. 7/1983 tentang Pajak Penghasilan sebagaimana telah diubah dengan UU no. 7/1981 (*Revision of Government Law no. 7/1983 about Income Tax, as has been revised by Government Law no 7/1981*), [Online] Undang-Undang no 10/1994 (*Government Law no. 10//1994*), in effect since 1 January 1995, Available from: http://www.pajak.go.id/peraturan/view_doc?docid=16andsearchterm16&searchterm=None.

Scenario	% change	IRR (%)
Original	-	5.77%
Benchmark	-	12.75%
Increase in electricity tariff or electricity generation	125 %	12.75%
Reduction in investment costs	57%	12.75%
Reduction in O&M Costs	100 %	7.21%

The revenue is based on the electricity tariff and production that are both unlikely to increase significantly. A strong increase of the electricity tariff is unlikely as the government is reluctant to increase the electricity costs for the consumer.

Tariff and PLF:

These results show that the IRR will hit the benchmark by increasing project revenue by 125 %. These variations are unlikely to occur, given the past circumstances and the fact that the Government of Indonesia was reluctant to increase the tariff. The electricity tariff is unlikely to increase more than 10% (based on the actual data on average selling price from 1991 to 2001, 2002, 2003 [27] since the tariff components increase in accordance with the countries inflation.

Investment cost:

On the other hand, an investment reduction is also unlikely to occur, since the construction has been completed and the material prices are increasing as inflation is applied each year in Indonesia. So, a 57% reduction in the investment will not be possible. Even if the project had not started, and 57% reduction in investment cost would be an unlikely event.

Operation cost:

Even if operation and maintenance cost were reduced by 100%, the calculated project IRR would still be under the benchmark. Only under very favourable circumstances, that are unlikely to occur during the project, could the benchmark be overcome.

In conclusion and overall this project is not financially attractive.

Step 4. Common Practice Analysis

Indonesia has an abundant amount of hydro resources that have not been fully utilized. According to publicly accessible governmental information, the potential capacity of hydro resources in Indonesia is 75,000 MW of which only 3,200 MW has so far been used to generate electricity (including captive power and private entities). Thus, hydroelectric generation cannot be considered to be common practice (detailed explanation is given in Step 4.a and 4.b of the Common Practice Analysis below):

Sub-step 4a. Analyse other activities similar to the project activity

Musi Hydroelectric Power Plant:

- located in Bengkulu province, Sumatra Island,

[27] Asian Development Bank report July 2003, *Impact evaluation study of Asian Development Bank Assistance to the power sector in Indonesia*, page 19-21 and www.pln.co.id

- run-off river type hydro power plant,
- electricity generation capacity of 210 MW.

In this section, Southern Sumatra is chosen for common practice comparison, since the project activity generates electricity that is delivered to Southern Sumatra grid only. In 1994 at investment decision date, Sumatra still consisted of two different grids; Northern Sumatra grid and Southern Sumatra grid. These grids were not yet interconnected. They have been interconnected in year 2007.
According to 1994 data of an installed power plant[28], two hydro power plants out of four power plants were installed in the province Bengkulu. The characteristics of all power plants are described in Table 7. Across the whole part of Southern Sumatra, only 15.47% of the total installed capacity of the power plants is generated through hydro power plants. In energy, the hydro power plants account for 97,460 kW in installed capacity out of 630,100 kW of installed capacity. Please see annex for list of power plant established up to year 1993.

Table 7 Installed Power Plant in Bengkulu Province

Type of Power Plant	Total Installed capacity (MW)	Operation start
Sukamerindu diesel power plant	15	1986
Pulau Baai diesel power plant	21	1975 – 1984
Tes I hydro power plant	1.3	1958
Tes II hydro power plant	17.6	1991

From the table above, two other hydro power plants exist in Bengkulu province, which have a capacity of 7.6% of Musi or less. The existing hydro power plants can't be compared to the project activity due to different technology, construction, complexity and size.
Therefore, the development of this type of project activity is not considered as common practice

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

The project activity possesses a much larger capacity than those hydro power plants that have been installed up to the year 1993 within Bengkulu province (see Table 7) while other installations are Diesel Power Plants. There are only two hydro power plants with much smaller capacity (1.3 MW and 17.6 MW) than this project activity.

Table 8 shows all installed hydro power plants across whole Southern Sumatra up to the year 1993.[29] Compared to all hydro power plants on the list, Musi HEPP installed capacity is way much higher thatn those stated in the table.

Table 8 Installed Hydro Power Plant in Southern Sumatra

Hydtro Power Plant in Southern Sumatra	Total Installed capacity (MW)	Operation start
Tes I hydro power plant	1.3	1958

[28] List of installed power plant is taken from the Emission Factor calculation for Sumatra Grid 2008. File has been submitted to the DOE.

[29] List of installed power plant is taken from the Emission Factor calculation for Sumatra Grid 2008. File has been submitted to the DOE.

Tes II hydro power plant	17.6	1991
PLTA MJAU	68	1983
PLTA BAGM (Ebara)	10.5	1976

Therefore no similar options exist that are comparable to the project activity.

In conclusion the proposed project is deemed to be additional according to ACM0002.

3 Monitoring:

3.1 Title and reference of the VCS methodology (which includes the monitoring requirements) applied to the project activity and explanation of methodology choices:

The project uses the CDM board-approved monitoring methodology ACM0002, "Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources", version 10, 11 June 2009.

The approved methodology of ACM0002 is chosen and applicable to the proposed project due to the following reasons:

- The project activity is the installation of a run-of-river hydroelectric power plant;
- The proposed project is not an activity that involves switching from fossil fuels to renewable energy at the site of the project activity,
- It is a greenfield project, with no existing reservoir before the project activity.
- It is connected with a regional power grid, the Sumatra grid; the Sumatra grid is clearly identified and information on the characteristics of this grid is publicly available from PLN Sumatra[30].

Based on the reasons stated above, the applicability criteria of the approved CDM methodology ACM0002 (version 10) have been met.

3.2 Monitoring, including estimation, modelling, measurement or calculation approaches:

- *Purpose of monitoring*
  To present reliable and complete data and to ensure that all actual project data is well organised in terms of collection and archiving.

- *Types of data and information to be reported, including units of measurement*
  - Net electricity generated in kWh
  - Amount of diesel fuel used in liter

- *Origin of the data*
  - Net electricity generated: Electricity Transfer Protocol Report in monthly basis.

  - Diesel fuel quantity: Diesel genset operational data

- *Monitoring, including estimation, modeling, measurement or calculation approaches*

[30] PLN Sumatra is a regional state owned electricity company in Sumatra

No estimation, modelling or measurement approach needs to be applied for accomplishing the monitoring report. All necessary monitoring data can be collected directly and used for the calculation of the emission reductions. Calculation of the emission reduction will be done as described in section 4 of this document.

- *Monitoring times and periods, considering the needs of intended users*
  - Net electricity generation will be monitored continuously and summarized in monthly electricity transfer protocol report.
  - Diesel used will be monitored monthly.
  All data will be summarized summarized regularly monthly or quarterly with regular yearly reports dependent on the monitoring plan for each data parameter for the entire crediting period.

- *Monitoring roles and responsibilities*
  Project proponents has assigned a team responsible for collecting all monitoring data and information. Please see annex for organisation structures.

- *Managing data quality*
  - Project proponent implements QA/QC procedures to ensure data quality. All meters and equipments measuring data will be calibrated on regular basis (generally yearly or two-year basis as defined in detail in section 3.3 of this document).

  .

3.3 Data and parameters monitored / Selecting relevant GHG sources, sinks and reservoirs for monitoring or estimating GHG emissions and removals:

Data and parameters to be monitored

<table>
<tr><td>Data/Parameter:</td><td>EG_y</td></tr>
<tr><td>Data unit:</td><td>kWh</td></tr>
<tr><td>Description:</td><td>Electricity supplied by the project activity to the grid.</td></tr>
<tr><td>Source of data to be used:</td><td>Measured by main electricity meter (Actaris type SL 7000) at the project activity site(the switch yard) .
Electricity Generation (EG) data used for monitoring is the monthly electricity generation delivered to grid summarized in Electricity Transfer Protocol Report signed by both parties of Generation department and Transmission department.
For ex-ante calculation, EG value uses the designed annual electricity generation provided by Musi FS Project Report 1993.</td></tr>
<tr><td>Value of data applied for the purpose of calculating expected emission reduction:</td><td><table>
<tr><td></td><td colspan="4">EG_y (kWh)</td></tr>
<tr><td></td><td>2006</td><td>2007</td><td>2008</td><td>2009-2025</td></tr>
<tr><td>Musi HEPP</td><td>1,140,000,000</td><td>1,140,000,000</td><td>1,140,000,000</td><td>1,140,000,000</td></tr>
</table></td></tr>
<tr><td>Description of measurement methods and procedures to be applied:</td><td>The net electricity sent to the grid will be measured by a watt-hour meter Actaris type SL 7000 (connected to a digital control system and recorded continuously), which can measure power produced, used and delivered to the grid.
The measurement of electricity generation will be conducted on a continuous basis, where monthly data is recorded and continuous total electricity measurement will be available. The measurement results will be summarised in regular production reports.</td></tr>
<tr><td>QA/QC procedures to</td><td>The QA/QC will be conducted through cross-checking with sales electricity</td></tr>
</table>

be applied:	receipts. Meters will be calibrated on yearly basis according to the Standard Operational Procedures (SOP) from PLN or other documents, which update or replace the SOP. Data measured by meters will be cross-checked by electricity sales receipts. The meter (s) will either: i) be read frequently and jointly by the project proponent in Generation unti and Transmission unit ii) be read by the project proponent and the data will then be double checked with the electricity sales receipts using comparison meter **iii)** only be read by the grid company
Any comment:	-

Data/Parameter:	$FC_{i,y}$
Data unit:	ton
Description:	Amount of diesel fuel used in the hydropower plant operation during the year y
Source of data to be used:	Measured - Project Owner-diesel fuel operational logbook
Value of data applied for the purpose of calculating expected emission reduction:	0.28 The data above is the highest data based on actual data recorded by project.
Description of measurement methods and procedures to be applied:	Fuel consumption will be recorded monthly, specifically for each fuel (currently only diesel consumption is available). Fuel consumption will be calculated from static graduated level gauges on the fuel injection tanks by using emergency diesel genset, resulted in litres then converted to tonnes using fuel specific density or scientifically proven fuel densities.
QA/QC procedures to be applied:	-
Any comment:	Fuel consumption will only occur in emergencies when power plant is not operational and the grid is also not available, a confluence of events which is expected to happen very rarely; at other times the plant will run on grid electricity. Emergency diesel genset is only for critical instrument/control system during turbine trip and shutdown.

Data and parameters to be available during validation for emission reduction calculation:

Data/Parameter:	$EF_{grid,CM,y}$
Data unit:	tCO_2/MWh
Description:	Grid Emission Factor of Sumatra
Source of data to be used:	DNA of Indonesia http://dna-cdm.menlh.go.id/id/database/DNA CDM_Grid_Sumatera_JAMALI_2008
Value of data applied for the purpose of calculating expected emission reduction:	0.743

Description of measurement methods and procedures to be applied:	No measurement required. Data is obtained based on analysis of DNA published information following the "Tool to calculate the emission factor for an electricity system" (EB 35 Annex 12).
QA/QC procedures to be applied:	-
Any comment:	-

Data/Parameter:	$NCV_{i,y}$
Data unit:	TJ/ton
Description:	Net calorific value of diesel fuel
Source of data to be used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories (Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Workbook volume 2 chapter 1 Table 1.2).
Value of data applied for the purpose of calculating expected emission reduction:	0.043
Description of measurement methods and procedures to be applied:	–
QA/QC procedures to be applied:	-
Any comment:	–

Data/Parameter:	P_i
Data unit:	kg/m^3
Description:	Density of diesel fuel
Source of data to be used:	Pertamina diesel fuel specification[31]
Value of data applied for the purpose of calculating expected emission reduction:	0.815
Description of measurement methods and procedures to be applied:	–
QA/QC procedures to be applied:	-
Any comment:	–

Data/Parameter:	$EF_{CO2,i,y}$
Data unit:	tCO_2/TJ
Description:	Weighted average CO_2 emission factor of diesel fuel in year 'y'
Source of data to be used:	IPCC default value is used (Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Workbook volume 2 chapter 1 Table 1.4)..
Value of data applied for the purpose of calculating expected	74.1

[31] Pertamina Solar Characteristic

emission reduction:	
Description of measurement methods and procedures to be applied:	–
QA/QC procedures to be applied:	-
Any comment:	–

3.4 Description of the monitoring plan

This section details the steps taken to monitor on a regular basis the GHG emissions reductions from the Musi Hydroelectric Power Plant Project in Indonesia in accordance with ACM0002 version10.

The Monitoring Plan for this project has been developed to ensure that the project collects and archives complete data from the very start.

1. Monitoring organisation

The monitoring team has been established and integrated within the existing organization structure of the Musi hydropower plant prior to the start of the verification. Clear roles and responsibilities are assigned to all staff involved in the VCS project and the prospect of nominating a VCS manager (it is written CDM manager as VCS manager in the structures, please see annex) have been considered. The VCS manager has the overall responsibility for the monitoring system on this project.

All other VCS monitoring staff have clearly defined roles and responsibilities. The VCS Manager manages the process of training new staff, ensuring trained staff performs the monitoring duties properly, and ensuring that where trained monitoring staff are absent, the integrity of the monitoring system is maintained by other trained staff.

A formal set of monitoring procedures is established prior to the start of the project. These procedures will detail the organisation, control and steps required for certain key monitoring system features, including:

a) VCS staff training
b) VCS data and record keeping arrangements
c) Data collection
d) VCS data quality control and quality assurance
e) Equipment maintenance
f) Equipment calibration
g) Equipment failure

The procedures will be agreed and signed off by PT PLN (Persero) and South Pole Carbon Asset Management Ltd. Any changes to procedures will need to be agreed by both parties. The VCS Manager will be responsible for ensuring that the procedures are followed on site and for continuously improving the procedures to ensure a reliable monitoring system is established.

2. Monitoring equipment and installation

Given the emission factor is calculated *ex-ante* and according to the Monitoring Methodology ACM0002 ver 10, the only data to be monitored is electricity supplied to the grid by the project (detailed in section 3.3).

<u>Metering of Electricity Supplied to the Grid</u>

The main electricity meter of each power generation unit for establishing the electricity delivered to the grid (detailed in section 3.3) is installed at the transaction point of Musi Power Plant and PLN grid (Sumbagsel sub-station). This electricity meter will be the main meter (revenue meter) that measures the quantity of electricity supplied to the grid that will be paid by the PLN. As this meter provides the main VCS measurement, it will play a key role in the verification process.

The project developer owns the meter and is responsible for its maintenance and calibration, as stated in the SOPs agreed upon with the PLN. PLN and its representative are entitled to be present during any test, inspection, maintenance, and replacement of any part of the metering system, which will be performed by the meter manufacturer on request of the project developer.

To ensure maximum data availability and to introduce data quality controls, three cross-check meters are installed in addition to the revenue meter for each power generation unit. Those meters are located at the Musi power station, measuring electricity production from the project and own consumption.

Electricity meters should meet the relevant local standards at the time of installation. Before the installation of the meters, they should be calibrated by the manufacturer. The meters will be installed by the project developer according to the following national Indonesian standard "Standard Electricity Meter Equipment". Records of the meter (type, make, model and calibration documentation) is shown in the table below.

All equipment will be calibrated by the manufacturer according to relevant local standards at the time of installation and maintained in accordance with the manufacturer's recommendations to ensure accuracy of measurements. Records of the meter (type, make, model, calibration, and maintenance documentation) will be retained as part of the VCS monitoring system.

Below are the characteristic of the kWh main-meters at Musi HEPP

No	Description	
1	Electricity Meter Transfer 1 from power generation unit 1, Musi HEPP	Type: Actaris type SL 7000 Serial Number: 36027156 Class: 0.2 Date of Calibration: 28/07/05, valid until 28/07/10 After registration of the project meter will be calibrated on a yearly basis to comply with the monitoring requirements of the project activity
2	Electricity Meter Transfer 2 from power gneration unit 2, Musi HEPP	Type: Actaris type SL 7000 Serial Number: 36027159 Class: 0.2 Date of Calibration: 28/07/05, valid until 28/07/10 After registration of the project meter will be calibrated on a yearly basis to comply with the monitoring requirements of the project activity
3	Electricity Meter Transfer 3 from power generation unit 3, Musi HEPP	Type: Actaris type SL 7000 Serial Number: 36027158 Class: 0.2 Date of Calibration: 28/07/05, valid until 28/07/10 After registration of the project meter will be

Quality Control

The main meter of each power generation unit is owned by the project developer and installed at the transaction point of PLN grid. The project developer specifies the QA procedure for measurement and calibration to ensure the measurement accuracy of the main meter. Periodic checks should be conducted according to the relevant national standard[32]. In the event of: any seal securing the metering system is broken, the system fails to register, or the measurement result is found (upon testing) to vary more than the allowable error from the standard meter used in the test, then an adjustment shall be made correcting all measurements of energy made by the metering system, as described in the PPA.

In case of failure of the main meter, production meter and own consumption meter which also located at generation site of each power generation unit will be used as cross-check meters, measuring the quantity of electricity exported from the project. The difference between electricity produced and consumed on-site shall be valid for claiming carbon credits. In the special case of total failure of all meters no credits will be claimed during such period.

During monthly monitoring of electricity delivered, the main meter and check-meters will be read and if the difference between the respective main meter and check-meters exceeds the maximum error for such meters then all meters shall be tested in turn. The main meter shall be used as transfer data and provide a letter of agreement.

During testing, if all meters are found to be working beyond the permissible limits of error, then the electricity delivered for the previous billing month shall be corrected to account for this error. The meters shall be calibrated and data will be calculated manually. However, manually calculated electricity production will not be used to claim carbon credits.

During annual calibrations, if the main meter is found to be within the permissible limits of errors, and the check-meters are found to be beyond the permissible limits of errors, the main meter shall be used for electricity delivered.

In case, during the annual tests, the main meter is found to be beyond the permissible limit of error but check-meters are found to be within the permissible limit of error, then check-meters reading shall be used for electricity delivered.

In case, during annual tests, both, the main meter and the check-meters are found to be beyond the permissible limit of error, then the meters shall be replaced with spare set of calibrated meters.

The electricity delivered for this period (from the date of last calibration) shall be corrected for the maximum error in meters.

3. Data recording procedure

The procedures for collecting the electricity meter data will be outlined in the Standard Operating Procedure signed between the Generating Unit and the Transmission Unit, which both are under PLN.

[32] Indonesian Government (1981) Metrologi Legal, [Online], Government Law no. 02/1981, in effect since 1 April 1981, Available from: http://www.unmiset.org/legal/IndonesianLaw/uu/Uu198102.htm. [Accessed 13 June 2007]

All relevant data will be archived electronically and backed up regularly. Uncertainty will be considered to achieve conservative results. Moreover, it will be kept for the full crediting period, plus two years after the end of the crediting period or the last issuance of VCUs for this project activity (whichever occurs later). The Monitoring Plan has been developed to ensure that the project has robust data collection, processing, and archiving procedures.

Other data for VER procedures will be managed by the dedicated VCS Manager.

EG recording procedure and Monthly Electricity Protocol Report (Berita Acara):

- Operating and maintenance supervisor (O & M supervisor) responsible for recording the amount of EG exported by Generating unit as the result from kWh meter downloading
- Operating and maintenance supervisor responsible for constructing the electricity generating protocol report which includes calculation of net electricity delivered to PLN transmission unit. This report has to be reported and signed by Unit Manager, which will then be further reported to the Sector Manager. VCS manager will have the copy of such report and be notified as well.
- O & M supervisor with other authorized staff from Generating unit will attract the data by downloading via computer from the kWh electronic meter and then record it in the form of Monthly Electricity Protocol (MEP) which shall be signed by both Generating unit (PLN Musi Generating Unit) and PT. PLN (transmission unit). The joint meter reading taken at the transaction point is witnessed by the presence of P3B officials as transmission department and the PP representative as generation department.
- The MEP will be then rechecked by authorized person from Transmission unit for Bandar Lampung sector.

After all such information is rechecked and agreed by all related parties, the MEP will be signed by all authorized parties from Generating unit and Transmission unit. The report will thus be sent to PLN Palembang as headquarter for all power plant units in Southern Sumatra.

Main meter failure – use of cross-check meter data

If the main electricity meter is found to be faulty during its reading, data from the the production and own consumption meter will be used in its place. In this circumstance, the electricity exported to the grid should be calculated as follows:

a) The data from the production and own consumption meter will be used for the period of the main meter failure. with a minor adjustment to allow for transmission losses.
b) The electricity used and measured for own consumption should be deducted from the produced electricity measured. The difference will be equal to the net electricity produced.

Cross-check meter failure

A failing cross-check meter will be repaired or replaced by an accredited equipment testing organization appointed by PLN. Maintenance records and any calibration documents will be retained by the project and ensured by the operation and maintenance supervisor that the calibration documents comply with calibration requirements. In case of a cross-check meter failure simultaneously to a main meter failure no electricity produced can be measured and therefore no credits can be claimed.

Possible fault with either meter

During the process of cross-checking the electricity data from the meters, a difference may be established that is considerably larger than the historic difference (allowing for transmission losses). In this unlikely event, it could be either electricity meter at fault. The data recording procedures for this circumstance will be specified in a separate procedure.

4. Data and records management

At the end of each month the monitoring data needs to be filed electronically. The electronic files need to have CD back-up and/or print-out. The project developer needs to keep electricity sale and purchase invoices. All written documentation such as maps, drawings, the EIA and the Feasibility study, should be stored and should be available to the verifier so that the reliability of the information may be checked.

In order to make it easy for the verifier to retrieve the documentation and information in relation to the project emission reduction verification, the project developer should provide a document register. The document management system will be developed to ensure adequate document control for VCS purposes.

The dedicated VCS Manager of the project developer is responsible for checking the data (according to a formal procedure) and the VCS Manager will be responsible for managing the collection, storage and archive of all data and records. A procedure will be developed to manage the VCS record keeping arrangements. All the data shall be kept until two years after the end of credit period.

4 GHG Emission Reductions:

4.1 Explanation of methodological choice:

As demonstrated in 2.2, the project activity meets the applicability requirements of chosen methodology ACM0002 – "Consolidated baseline methodology for grid connected electricity generation from renewable sources" Version 10, EB 47.

According to the latest version of ACM0002 version 10, the procedure of determining baseline emission, project emission, leakage, and emission reduction for the project activity are as follows:

Baseline Emission

Baseline emissions include only CO_2 emissions from electricity generation in fossil-fuel-fired power plants that are displaced due to the project activity, calculated as follows:

$$BE_y = EG_{PJ,y} * EF_{grid,CM,y} \quad (1)$$

Where:

BE_y	=	Baseline emissions in year *y* (tCO2/yr)
$EG_{PJ,y}$	=	Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in year y (MWh/yr)
$EF_{grid,CM,y}$	=	Combined margin CO_2 emission factor for grid connected power generation in year *y* (ton CO_2 /MWh)

Calculation of $EG_{PJ,y}$

For Greenfield renewable energy power plants:

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

Where:

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

Calculation of $EF_{grid,CM,y}$ of Sumatera grid

The Grid Emission Factor used in the calculation is calculated as a combined margin (CM), consisting of the combination of Operating Margin (OM) and Build Margin (BM) according to the procedures prescribed in the "Tool to calculate the emission factor for an electricity system", Version 01.1, 29 July 2008 (EB 35, Annex 12).

According to the tool, following steps are applied:

Step 1. Identify the relevant electric power system
Step 2. Select an operating margin (OM) method
Step 3. Calculate the operating margin emission factor according to the selected method
Step 4. Identify the cohort power units to be included in the build margin (BM)
Step 5. Calculate the build margin emission factor
Step 6. Calculate the combined margin (CM) emission factor

Step 1. Identify the relevant electric power system

According to the latest version of the tool, the Sumatra power grid is selected as the project boundary, as the regional interconnected grid covering all provinces in Sumatra Island. The project is located in North Sumatra province, and is connected to the existing Sumatra power transmission line. The Sumatra power grid is therefore determined as the project boundary. Both the OM and the BM will be calculated ex-ante.

Step 2. Select an operating margin (OM) method

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

(a) Simple OM, or
(b) Simple adjusted OM, or
(c) Dispatch data analysis OM, or
(d) Average OM.

In order to apply the simple OM method the low-cost/must run ration of the grid shall be below 50%. The grid connected to the project activity had ratios of 20.95%, 17.28%, 19.52%, 21.99% in the years 2003 to 2007, which are all below the 50% threshold. The calculation of such has been further elaborated in the Indonesian DNA approved emission factor calculation.

Step 3. Calculate the operating margin emission factor according to the selected method

The Operating Margin will be calculated ex-ante, therefore the factor is calculated based on three (3) recent years available data.

$$EF_{OM,simple,y} = \frac{\sum_{i,m} FC_{i,j,y} \cdot NCV_{i,y} \cdot EF_{CO2,i,y}}{\sum_{m} EG_{j,y}} \quad (3)$$

Where:

$EF_{OMsimple,y}$	=	Simple operating margin CO_2 emission factor in year y (tCO_2/MWh)
$FC_{1,y}$	=	Amount of fossil fuel type I consumed in the project electricity system in year y (mass or volume unit)
$NCV_{i,y}$	=	Net caloric value (energy content) of fossil fuel I in year y (GJ / mass or volume unit)
$EF_{CO2,I,y}$	=	CO_2 emission factor of fossil fuel type I in year y (tCO_2/GJ)
EG_y	=	Net electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants / units, in year y (MWh)
i	=	All fossil fuel types combusted in power sources in the project activity system in year y
y	=	Either the three most recent years for which data is available at the time of submission of the CDM-PDD to the DOE for validation (ex-ante option) or the applicable year during monitoring _ex-post option), following the guidance on data vintage in step 2

Step 4. Identify the cohort power units to be included in the build margin (BM)

The Project Developer can choose to use following options to calculate Build Margin Emission Factor ($EF_{BM,y}$), which is based on a sample group m that consists of either one of the following; whichever comprises the larger annual generation:

a. five power plants that have been built most recently, or
b. power plant capacity additions that comprises 20% of the system generation that have been built most recently

In terms of vintage of data, the project participant can choose one of the following options:

Option 1
"For the first crediting period, calculate the build margin emissions factor ex-ante based on the most recent information available on units already built for sample group m at the time of VCS-PD submission to the DOE for validation. For the second crediting period, the build margin emission factor should be updated based on the most recent information available on units already built at the time of submission of the request for renewal of the crediting period to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used. This option does not require monitoring emission factor during the crediting period."

Option 2
"For the first crediting period, the build margin emission factor shall be updated annually, ex-post, including those units built up to the year of registration of the project activity or, if information up to the year of registration is not yet available, including those units built up to the latest year for which information is available. For the second crediting period, the build margin emission factor shall be calculated ex-ante, as described in Option 1 above. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used."

Based on calculation, the set of power units describe as (b) in Sumatra grid comprises the larger annual generation than that of (a), the sample group (b) should be used for calculating the build margin of Sumatra grid.

Step 5. Calculate the build margin emission factor

Once the sample group 'm' is defined, the build margin is calculated ex-ante using the following equation:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}} \quad (4)$$

Where:

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

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

The combined margin emissions factor is calculated as follows:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times w_{OM} + EF_{grid,BM,y} \times w_{BM} \quad (5)$$

Where:

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

Project Emission

For most renewable power generation project activities, $PE_y = 0$. However, some project activities may involve project emissions that can be significant. These emissions shall be accounted for as project emissions by using the following equation:

$$PE_y = PE_{FF,y} + PE_{GP,y} + PE_{HP,y} \quad (6)$$

Where:

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

The project activity is a run-off-river type hydropower project. According to the methodology (for hydropower project activities that result in new reservoirs and for hydropower project activities that result in the increase of existing reservoirs), project proponents shall account for CH_4 and

CO_2 emissions from the reservoir. Since project activity in a Greenfield project, the *$PE_{HP,y}$* could be neglected or zero *(0)*.

Project emissions could occur by the backup diesel generator and got taken into account. The function of the backup diesel generator is to supply emergency power to start the turbines and generators when the power plant is accidentally fully stopped and the electricity supply from the connected grid is failed. It will be operating only a few hours per year.

The records on diesel consumption are made on a daily basis in the genset operation logbook. This has been included in the project emission calculation from the project activity. The basis for calculation is the values of density of diesel and emission factor for diesel.

Project emissions from diesel fuel consumption, $PE_{FF,y}$, during the entire crediting period are calculated as follows, whereby $PE_{FF,y} = PE_{FC,j,CO2}$:

"Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" (version 02)

$$PE_{FC,j,CO2} = \Sigma FC_{i,j,y} \times COEF_{i,y} \quad (8)$$

Where:

Parameter	Description	Unit	Value	Source
$PE_{FC,j,CO2}$	CO_2 emissions from fossil fuel combustion in process j during year y	tCO_2/y	Calculated	Equation 8
$FC_{i,j,y}$	Quantity of fuel type i combusted in process j during the year y	ton/y	Measured	Musi HEPP
$COEF_{i,y}$	CO_2 emission coefficient of fossil fuel type i in year y	tCO_2/ton	3.1863	Equation 9
i	Fuel types combusted in process j during year y	-	i= Diesel oil	Musi HEPP

$COEF_{i,y}$ is calculated using option B. Option B calculates $COEF_{i,y}$ based on net calorific value and CO_2 emission factors of fuel type i, as follows:

$$COEF_{i,y} = NCV_{i,y} \times EF_{CO2,i} \quad (9)$$

Where:

Parameter	Description	Unit	Value	Source
$COEF_{i,y}$	CO_2 emission coefficient of fossil fuel type i in year y	tCO_2/ton	3.1863	Equation 9
$NCV_{i,y}$	Weighted average net calorific value of fuel type i in year	TJ/t	0.043	IPCC 2006 default for diesel oil
$EF_{CO2,i}$	Weighted average CO2 emission factor of fuel type i in year y	tCO_2/TJ	74.1	IPCC 2006 default for diesel oil
i	Fuel types combusted in process j during year y	-	i= Diesel oil	Musi HEPP

Leakage

According to the methodology, leakage from related emission sources do not need to be considered, thus leakage is zero.

$$L_y = 0$$

Emission Reductions

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \qquad (10)$$

Where:

ER_y	=	Emission reduction in year *y* (t CO_2e/yr)
BE_y	=	Baseline emissions in year *y* (t CO_2e/yr)
PE_y	=	Project emissions in year *y* (t CO_2e/yr)
LE_y	=	Leakage emissions in year *y* (t CO_2e/yr)

4.2 Quantifying GHG emissions and/or removals for the baseline scenario:

According to the latest version of ACM0002 version 10, the procedure of determining baseline emission, project emission, leakage, and emission reduction for the project activity are as follows:

Baseline emissions

$$BE_y = EG \cdot EF_{grid,CM,y} \qquad (11)$$

Parameter	Description	Unit	Value	Source
BE_y	Baseline emissions in year *y*	tCO2/yr	847,020	Calculated equation 11
$EG_{PJ,y}$	Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in year y	MWh/yr	1,140,000	Planned electricity production as per feasibility study
$EF_{grid,CM,y}$	Combined margin CO_2 emission factor for grid connected power generation in year *y*	ton CO_2 /MWh	0.743	See explanation below

Calculation of $EF_{grid,CM,y}$

As per newest "Tool to calculate the emission factor for an electricity system" for each crediting period the most recent data available at time of submission of the PD to the DOE for validation shall be used. The latest available data at the time is the official emission factor published by the Indonesian DNA using data from the year 2008 concluding an emission factor of 0.743 tCO_2e/MWh.

Summary of Baseline Emissions (BE_y)

Year	Vintage	BE_y (tCO_2e)
2006 – 2007	1 August 2006 – 31 July 2007	**847,020**
2007 – 2008	1 August 2007 – 31 July 2008	**847,020**

2008 – 2009	1 August 2008 – 31 July 2009	**847,020**
2009 – 2010	1 August 2009 – 31 July 2010	**847,020**
2010 – 2011	1 August 2010 – 31 July 2011	**847,020**
2011 – 2012	1 August 2011 – 31 July 2012	**847,020**
2012 – 2013	1 August 2012 – 31 July 2013	**847,020**
2013 – 2014	1 August 2013 – 31 July 2014	**847,020**
2014 – 2015	1 August 2014 – 31 July 2015	**847,020**
2015 – 2016	1 August 2015 – 31 July 2016	**847,020**

4.3 Quantifying GHG emissions and/or removals for the project:

Project Emission

$PE_y = PE_{FF,y} + PE_{GP,y} + PE_{HP,y}$ (12)

Parameter	Description	Unit	Value	Source
PE_y	Project emissions in year *y*	tCO_2e/yr	0	Calculated, equation 12
$PE_{FF,y}$	Project emissions from fossil fuel consumption in year y	tCO_2/yr	0	"Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" as calculated below
$PE_{GP,y}$	Project emissions from the operation of geothermal power plants due to the release of non-condensable gases in year *y*	tCO_2/yr	0	Project activity is not a geothermal powerplant
$PE_{HP,y}$	Project emissions from water reservoirs of hydro power plants in year y	tCO_2/yr	0	Musi HEPP is a run-off river hydro powerplant.

Project emissions from the consumption of fossil fuels

$PE_{FF,y} = PE_{FC,j,CO2}$, if $PE_{FC,j,CO2}$ > 1% of total emission reduction. Otherwise $PE_{FF,y} = 0$ shall be applied following the methodology.

$PE_{FC,j,CO2} = \Sigma FC_{i,j,y} \times COEF_{i,y}$ (14)

Parameter	Description	Unit	Value	Source
$PE_{FC,j,CO2}$	CO_2 emissions from fossil fuel combustion in process j during year y	tCO_2/y	1	Calculated, Equation 14
$FC_{i,j,y}$	Quantity of fuel type i combusted in process j during the year y	ton/y	0.28	Musi HEPP
$COEF_{i,y}$	CO_2 emission coefficient of fossil fuel type i in year y	tCO_2/ton	3.1863	Calculated Equation (9)
i	Fuel types combusted in process j during year y	-	i= Diesel oil	Musi HEPP

Using “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion” (Version 02), the result of $PE_{FC,j,CO2}$ calculation is tabulated as follows:

Year	Vintage year	$PE_{FC,CO2}$
2006 – 2007	1 August 2006 – 31 July 2007	1
2007 – 2008	1 August 2007 – 31 July 2008	1
2008 – 2009	1 August 2008 – 31 July 2009	1
2009 – 2010	1 August 2009 – 31 July 2010	1
2010 – 2011	1 August 2010 – 31 July 2011	1
2011 – 2012	1 August 2011 – 31 July 2012	1
2012 – 2013	1 August 2012 – 31 July 2013	1
2013 – 2014	1 August 2013 – 31 July 2014	1
2014 – 2015	1 August 2014 – 31 July 2015	1
2015 – 2016	1 August 2015 – 31 July 2016	1
Total project emissions (ton CO_2)		10
Total project emissions to baseline emissions (%)		0.0001

The total PE $_{FC,j,CO2}$ is 10 ton CO_2 while the total projected emission reductions are 8,470,200 ton CO_2. Since total PE $_{FC,j,CO2}$ accounts for less than 1% of the baseline emissions, and in accordance with ACM0002 version 10, the project emission can be neglected.

4.4 Quantifying GHG emission reductions and removal enhancements for the GHG project:

Leakage Emissions

According to ACM0002, the leakage of the proposed project is not considered. No leakage is expected. Therefore, $L_y = 0$.

$$L_y = 0$$

The ex-ante emission reductions calculations are as follows:

$$ER_y = BE_y - PE_y - L_y$$

Therefore using the calculation above the total baseline emission for the 10-year crediting period is 8,470,200 tCO_2e or 847,020 tCO_2e/year, as shown in the summary below:

Year	Vintage	Project emission (tCO_2e)	Baseline emission (tCO_2e)	Leakage emission (tCO_2e)	Overall emission reductions (tCO_2e)
2006 – 2007	1 August 2006 – 31 July 2007	0	847,020	0	847,020
2007 – 2008	1 August 2007 – 31 July 2008	0	847,020	0	847,020
2008 – 2009	1 August 2008 – 31 July 2009	0	847,020	0	847,020
2009 – 2010	1 August 2009 – 31 July 2010	0	847,020	0	847,020
2010 – 2011	1 August 2010 – 31 July 2011	0	847,020	0	847,020
2011 – 2012	1 August 2011 – 31 July 2012	0	847,020	0	847,020
2012 – 2013	1 August 2012 – 31 July 2013	0	847,020	0	847,020

2013 – 2014	1 August 2013 – 31 July 2014	0	847,020	0	847,020
2014 – 2015	1 August 2014 – 31 July 2015	0	847,020	0	847,020
2015 – 2016	1 August 2015 – 31 July 2016	0	847,020	0	847,020
	Total CO_2 reduction		8,470,020		8,470,020

5 Environmental Impact:

According to the Decree of the Ministry of Environment No. 17/2001, all hydroelectric power plants with a dam height of ≥ 15 meters, or flooded area of ≥ 200 ha or installed capacity of ≥ 50 MW need to undertake an Environmental Impact Assessment (EIA). The Musi Hydroelectric Power Plant project has an installed capacity of total 210 MW electricity, therefore this project requires an EIA.

Table 9 Summary of EIA findings

Identified environmental impacts	Measures taken
Pre-Construction phase	
Social responsibility	
Community perception related to project consultation, publicising and resettlement	Perform discussion with local community, monitor the issues that develop in the community
Construction phase	
Air and noise pollution	
Increase of air and noise pollution due to increased transportation and operation of heavy equipment	Restrict the use of heavy equipment operation during the day, build project fence to reduce noise pollution, spray water to avoid dust from construction, control vehicle emission and noise, use protective masks for employees
Water pollution	
Change in surface water flow due to land clearing and covering	Create a drainage system to the nearest water body, perform a gradual land covering based on project phase, execute land clearing only on the project site.
Solid waste	
Construction waste from the transportation of soil material	Perform continuous cleaning during the construction period to remove debris and deposit them appropriately
Biodiversity and ecosystems	
Change in biodiversity due to alteration in land and water body conditions	Reforest and restore the green lands after the construction, maintain a minimum river flow to preserve the natural biodiversity within the river.
Employment impacts	
Utilisation of local human resources	Give priority to local employment, hold special training to enhance the local community's skills.

Identified environmental impacts	Measures taken
Operation phase	
Water pollution	
Decrease in the quality and quantity of water due to the wastewater from plant's activity and land erosion	Operate wastewater treatment plant, reforest the watershed area
Environmental	
Related to the project operation and its supporting facility, solid waste and wastewater from the surrounding settlement	Build a wastewater treatment facility, execute a solid waste temporary disposal system, create a waste transportation system

Spatial planning	
Changing in spatial planning structure due to project activity	Control the development around project activity by enforcing the appropriate planning regulations
Regional image	
Changing in regional image due to the development in the region	Planning controls will ensure sensitive development of the region
Traffic	
Increase traffic activity due to the project's operational activity	Restore the trans-Sumatra main road and set-up traffic signs
Health and Safety	
Human resources needed to operate the project and its facilities	Provide employment opportunities to local human resources following high Health and Safety standards
Working opportunity and income	
Related to utilisation of local human resources	Give priority to the admission of local human resources, hold special training to enhance the local community's skills.
Comfort	
Uncomfortable conditions due to vehicle's activity on the access road from and/or to the project	Maintain the road condition by setting-up traffic signs and planting trees on the road side
Social responsibility	
Community perception related to project operation	Contribution to the surrounding environment by building school and local health service.

With mitigation controls planned as part of the project construction and EIA process, and the contribution made by the project to sustainable development for the local and national area, the project is expected to have an overall positive impact on the local and global environment. All negative environmental impacts are subject to mitigation measures as described above.

6 Stakeholders comments:

A meeting with relevant stakeholders which was held on 6 May 2003, including the village chief and people who live nearby, within the project boundary of Musi hydro power plant was conducted for the purpose of the EIA. As documented in the EIA, the local stakeholders have perceived that the construction of Musi Hydro has increased their social and economical life due to road construction, additional earning from temporary jobs, and especially due to the additional supply of electricity.

Outcome: No negative comments were received from the local stakeholders during the meeting. They did not object to the project activity because the project will not negatively impact the surrounding environment or people.

7 Schedule:

Project start date:
Unit 1: 19 July 2006,
Unit 2: 19 July 2006,
Unit 3: 19 July 2006,
Thus, the project start date is 19 July 2006, as the earliest project start date of three units at Musi Hydro Power Plant.

Crediting period start date: 1 August 2006

Operational lifetime of project activity: 30 years

VCS crediting period: 10 years from 1 August 2006 until 31 July 2016.

8 Ownership:

8.1 Proof of Title:

Contract documents may be referred as the proof of the ownership the project activity,

8.2 Projects that reduce GHG emissions from activities that participate in an emissions trading program (if applicable):

Not applicable. PP has not participated in any other GHG emission credit program.

9 Annex:

List of Southern Sumatra power plants extracted from DNA approved emission factor calculation for Sumatra Grid 2008

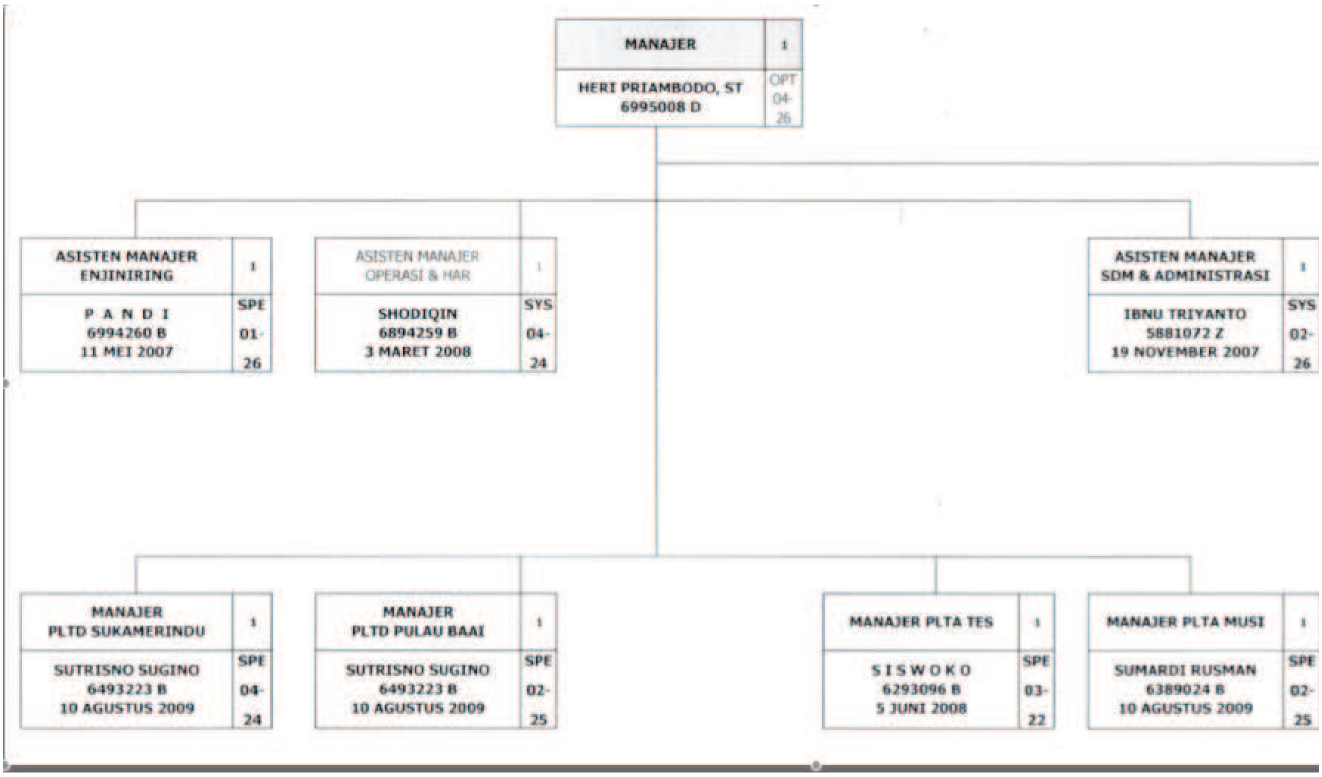
NO.	POWER PLANT		Unit	Install Capacity (kW)	Start of Operation	Electricity Production (MWh)

PT PLN SUMBAGSEL		Unit	Installed Capacity	Year	MWh
Keramasan Sector					
1	PLTU Keramasan 1	kw	12,500	1974	55,104
	PLTU Keramasan 2	kw	12,500	1974	70,150
2	PLTG Keramasan 1	kw	11,750	1976	53,987
	PLTG Keramasan 2	kw	11,750	1978	0
	PLTG Keramasan 3	kw	21,350	1983	65,240
7	PLTG/D Sungai Juaro 1	kw	12,600	1986	31,581
	PLTG/D Sungai Juaro 2	kw	12,600	1985	35,306
8	PLTD Kasang 1	kw	1,340	1974	0
	PLTD Kasang 2	kw	1,340	1974	0
	PLTD Kasang 3	kw	2,992	1977	0
	PLTD Kasang 4	kw	2,500	1981	0
	PLTD Kasang 5	kw	2,500	1983	642
	PLTD Kasang 7	kw	2,500	1984	1,918
9	PLTD Payo Selincah 1	kw	5,218	1987	9,798
	PLTD Payo Selincah 2	kw	5,218	1987	7,767
	PLTD Payo Selincah 4	kw	5,218	1987	11,116
	PLTD Payo Selincah 5	kw	5,218	1987	8,523
	PLTD Payo Selincah 6	kw	5,218	1993	12,453
	PLTD Payo Selincah 7	kw	5,218	1993	7,175
Total Installed Capacity			**139,530**		**370,759**
Bengkulu Sector					
	PLTD SKMD #5 [MIRRLS]	kw	5,218	1986	12,203

PLTD SKMD #6 [MIRRLS]	kw	5,218	1986	10,617
PLTD SKMD #7 [MIRRLS]	kw	5,218	1986	14,351
PLTD PBAAI #1 [SULZER]	kw	6,368	1984	27,740
PLTD PBAAI #2 [SULZER]	kw	6,368	1984	8,068
PLTD PBAAI #3 [MIRRLEES]	kw	2,420	1975	3,147
PLTD PBAAI #4 [MIRRLEES]	kw	2,420	1975	3,109
PLTD PBAAI #5 [SWD]	kw	4,040	1978	5,222
PLTA TES I #1 [SFAC]	kw	660	1958	2,582
PLTA TES I #2 [SFAC]	kw	660	1958	2,684
PLTA TES II #1 [HDR ART]	kw	4,410	1991	28,958
PLTA TES II #2 [HDR ART]	kw	4,410	1991	31,404
PLTA TES II #3 [HDR ART]	kw	4,410	1991	30,997
PLTA TES II #4 [HDR ART]	kw	4,410	1991	31,180
Total Installed Capacity		**56,230**		
Bukit Asam Sector				
PLTU BASAM # 1	kw	65,000	1987	436,053
PLTU BASAM # 2	kw	65,000	1987	433,747
PLTD BASAM #1 [SULZER]	kw	6,368	1984	0
PLTD BASAM #2 [SULZER]	kw	6,368	1984	4,779
Total Installed Capacity		**142,736**		**874,579**
Bandar Lampung Sector				
PLTD TRHN #1 [SULZER]	kw	6,368	1986	0
PLTD TRHN #2 [SULZER]	kw	6,368	1986	0
PLTD TRHN #4 [SWD]	kw	8,800	1987	12,097
PLTD TRHN #5 [SWD]	kw	8,800	1987	21,390
PLTD TRHN #6 [SWD]	kw	8,800	1987	0
PLTD TRHN #7 [WART]	kw	9,400	1991	28,623
PLTG TRHN [ALSTHOM]	kw	21,350	1982	22,487
PLTD TLBTG #3 [MAN]	kw	1,232	1960	1,312
PLTD TLBTG #4 [MAN]	kw	1,280	1970	1,250
PLTD TLBTG #5 [MAN]	kw	1,280	1970	1,253
PLTD TLBTG #7	kw	6,368	1976	0
PLTD TLBTG #8 [SWD]	kw	4,040	1978	8,324
PLTD TLBTG #10 [SULZR]	kw	6,368	1982	13,605
PLTD TGNN #1 [WART]	kw	9,400	1992	6,282
PLTD TGNN #2 [WART]	kw	9,400	1992	14,095
PLTD TGNN #3 [WART]	kw	9,400	1992	19,508
PLTD MTRO #3 [DHTS]	kw	250	1978	211
PLTD MTRO #6 [DHTS]	kw	500	1983	716
PLTD MTRO #9 [NIIGATA]	kw	3,000	1988	7,788

PLTD TLPD #1 [YANMAR]	kw	270	1982	340
PLTD TLPD #2 [YANMAR]	kw	270	1982	332
PLTD TLPD #3 [YANMAR]	kw	270	1982	347
PLTD TLPD #4 [YANMAR]	kw	270	1982	337
PLTD TLPD #6 [WART]	kw	1,240	1990	1,094
PLTD TLPD #7 [WART]	kw	1,240	1990	1,733
PLTD TLPD #8 [WART]	kw	1,240	1990	1,618
Total Installed Capacity		**127,204**		**164,743**
Ombilin Sector				
PLTG PLIMO #1 [ALSTOM]	kw	21,350	1983	22,970
PLTG PLIMO #2 [ALSTOM]	kw	21,350	1983	31,665
Total Installed Capacity		**42,700**		**54,634**
Bukittinggi Sector				
PLTA MJAU #1 [TOSHIBA]	kw	17,000	1983	46,979
PLTA MJAU #2 [TOSHIBA]	kw	17,000	1983	45,447
PLTA MJAU #3 [TOSHIBA]	kw	17,000	1983	66,285
PLTA MJAU #4 [TOSHIBA]	kw	17,000	1983	70,542
PLTA BAGM #1 [EBARA]	kw	3,500	1976	14,779
PLTA BAGM #2 [EBARA]	kw	3,500	1976	14,510
PLTA BAGM #3 [EBARA]	kw	3,500	1976	12,347
Total Installed Capacity		**78,500**		**270,889**
Total Sumbagsel (include rental)				**630,100**

Monitoring Organization Structure


MANAJER
1
HERI PRIAMBODO, ST
6995008 D
OPT 04-26
ASISTEN MANAJER ENJINIRING
1
P A N D I
6994260 B
11 MEI 2007
SPE 01-26
ASISTEN MANAJER OPERASI & HAR
1
SHODIQIN
6894259 B
3 MARET 2008
SYS 04-24
ASISTEN MANAJER SDM & ADMINISTRASI
1
IBNU TRIYANTO
5881072 Z
19 NOVEMBER 2007
SYS 02-26
MANAJER PLTD SUKAMERINDU
1
SUTRISNO SUGINO
6493223 B
10 AGUSTUS 2009
SPE 04-24
MANAJER PLTD PULAU BAAI
1
SUTRISNO SUGINO
6493223 B
10 AGUSTUS 2009
SPE 02-25
MANAJER PLTA TES
1
S I S W O K O
6293096 B
5 JUNI 2008
SPE 03-22
MANAJER PLTA MUSI
1
SUMARDI RUSMAN
6389024 B
10 AGUSTUS 2009
SPE 02-25