PROJECT DESIGN DOCUMENT FORM
FOR CDM PROJECT ACTIVITIES (F-CDM-PDD)
Version 04.1

PROJECT DESIGN DOCUMENT (PDD)

Title of the project activity	OML58 IPP Gas Fired Generation Project
Version number of the PDD	4
Completion date of the PDD	08/04/2014
Project participant(s)	• Nigerian National Petroleum Corporation • Total E&P Nigeria, Limited
Host Party(ies)	Federal Republic of Nigeria
Sectoral scope and selected methodology(ies)	• Sectoral Scope 1– Energy Industries (renewable - / non-renewable sources). • Methodology- AM0029 Version 3.0
Estimated amount of annual average GHG emission reductions	264,994 tons $CO_{2eq.}$

SECTION A. Description of project activity.

A.1. Purpose and general description of project activity

The proposed **CDM project activity** is the construction of a combined cycle, gas powered independent power plant (IPP) in the Niger Delta region of Nigeria. This project activity is designed to provide sustainable electricity to the Nigerian national grid on an on-going, reliable basis. The combined cycle plant design allows for utilization of the waste heat from the gas turbines to produce electricity thus increasing the plants efficiency. The GHG impact is positive in that the utilization of the waste heat results in lower CO_2 emissions per kWh than the grid thermal average. It provides for substantial and unequivocal sustainable development benefits.

The specific technical scope is the design and construction of 428MW Combined Cycle Gas Turbine (CCGT). The electricity produced will be dispatched into the national grid based on a Power Purchase Agreement (PPA) to be agreed with the Nigerian Bulk Electricity Trading PLC (NBET). The power will be evacuated to the grid by a 108km high-voltage (HV) transmission line outside the project boundary to the electrical sub-station at Onitsha.

The **existing situation** at the OML58 site contains major facilities related to upstream oil and gas production including producing wells, oil flow stations, gathering lines, gas processing facilities, and related pipelines for transporting the oil and gas. Commercial production began in 1962. OML58 is licensed by the Nigerian Government as an oil production block as per the terms of the Joint Operations Agreement between TOTAL E&P Nigeria, TEPNG, as operator and the Nigerian National Petroleum Corporation, NNPC. The specific site (12 hectares) for the IPP is a greenfield site within this block, and no previous infrastructure was located on this specific site.

The **baseline scenario**, as identified in section B.4 of this PDD, consists of building an Open Cycle Gas Turbine (OCGT) that would provide an equivalent level of electricity to the national grid. An OCGT represents a significantly less costly capital investment with lower operating costs compared to the CCGT. While less expensive to build and operate, an OCGT power plant has a significantly lower efficiency and a correspondingly higher emission factor per kWh. As demonstrated in this PDD, OCGT is the common practice in Nigeria and represents a cost effective way of reducing the developer's capital cost of a project that is neither in their business-as-usual operations nor provides investment returns comparable to that of their normal oil and gas activities.

Using the methodology and the relevant tools as guides for calculating the GHG reductions, the estimated **annual GHG reduction** is 264,994 tons of CO_2, which is expected to remain stable over the ten year crediting period.

In addition to the climate benefits, the project activity offers major **sustainable development benefits** including:

- supporting national and regional economic growth via increased capacity and reliability of the national electrical system
- creating jobs related to the building and running of the IPP as well as the creation of service related jobs within the community and regional level
- improving health of the population by reducing the need to run diesel powered generators via improved grid electricity

The most salient development benefit is simply **improved electrical supply** in a country plagued with a chronic electricity deficit and unreliable supply. The World Bank estimates that grid electricity meets only 30% of the country's demand for power and less than half the population has access to grid electricity.[1] As the current national grid is unable to meet the electrical needs of the nation, this severely impedes economic growth. For example, Nigeria with a population of 167 million has operating electrical capacity of between 3,000-6,000 MW[2]. Even for Africa, Nigeria's per capita consumption of 12 watts/year is strikingly low. For comparison, Gabon is 124, Zambia 67, Mozambique 51, Ghana and Cameroon 29 watts/year.[3] The Pew Center specifically cites the problems in Nigeria electricity and development:

> *….the negative impacts of low-quality electricity can be real and significant. A recent World Bank report estimated that 92 percent of manufacturing firms in Nigeria purchased and operated their own private sources of electric power due to Nigeria's chronically unreliable public power supply…. 1998 study estimated that the annual opportunity cost of poor quality electric service in Nigeria's economy exceeded $900 million.*
>
> Pew Center on Global Climate Change[4]

The direct relationship between energy consumption and economic growth in developing countries is well known.[5] This relationship is equally true in Africa, as research on 19 African countries finds:

> *Thus, we infer that the slow economic growth and high poverty levels that has been witnessed in many of these African countries is attributable to low per capita energy consumption. The findings of this study further suggest that long term development goals, such as achievement of MDGs may be hampered due to the sub-optimal investment in energy infrastructure.*
>
> C. Nondo, M. Kahsai[6]

This project activity will increase national electrical capacity by approximately 10%, and the plant's direct connection to its gas supply will allow it to avoid the gas supply interruptions common in Nigeria so as to allow it to provide stable and reliable electricity into the grid, thus directly and significantly contributing to sustainable, on-going, economic development.

According to the approved EIA for the project, the project activity will create **employment** during the construction period of between 500-1000 jobs and the working staff during operations will be approximately 100 people. Employment benefits extend beyond direct employment as noted in the EIA as this will have a multiplier effect of creating additional jobs in the community and encouraging local entrepreneurship (EIA, 5.6.2).

The project has strong **local environmental benefits** as well via reducing the need for diesel-powered generators in Nigeria. The acute shortage and erratic nature of the public power supply inhibits economic growth and has caused major reliance on diesel generators. Recurrent power outages force over 90 percent of industrial and a significant number of residential consumers to install and run their own power generators.[7] The wide reliance on diesel generators, especially in urban areas, creates major local

[1] World Bank, Project Information Document AB3797, 2008
[2] Available capacity and generation are available on the website of the "Federal Ministry of Power" http://www.power.gov.ng/
[3] CIA World Factbook (source data) https://www.cia.gov/library/publications/the-world-factbook, calculations on per capita statistics Wikipedia http://en.wikipedia.org/wiki/List_of_countries_by_electricity_consumption
[4] Pew Center on Global Climate Change; "Development Options and Global Climate Change: Electrical Power Options for Growth" June 1999 http://www.c2es.org/publications/developing-countries-global-climate-change-electric-power-options-growth
[5] Seung-Hoon Yoo, So-Yoon Kwak; "Electricity consumption and economic growth in seven South American countries" Energy Policy, Vol. 8 Issue 1 (January 2010)
[6] C. Nondo, M. Kahsai; "Energy Consumption and Economic Growth: Evidence from COMESA Countries", Southern Agricultural Economics Association Annual Meeting, Atlanta, Georgia, 2009
[7] World Bank, op cite

emissions of hazardous pollutants. The US EPA health assessment of the effects of diesel emissions finds:

> *… assessment concludes that long-term (i.e., chronic) inhalation exposure is likely to pose a lung cancer hazard to humans, as well as damage the lung in other ways depending on exposure. Short-term (i.e., acute) exposures can cause irritation and inflammatory symptoms of a transient nature, these being highly variable across the population… exacerbation of existing allergies and asthma symptoms is emerging. The assessment recognizes that DE emissions, as a mixture of many constituents, also contribute to ambient concentrations of several criteria air pollutants including nitrogen oxides and fine particles, as well as other air toxics.*
>
> US EPA[8]

As the project activity allows for improvements in reliable grid supply, one important impact is to reduce the use of diesel generators directly thereby contributing to improved human health in Nigeria.

A.2. Location of project activity

A.2.1. Host Party(ies)

Federal Republic of Nigeria

A.2.2. Region/State/Province etc.

Rivers State

A.2.3. City/Town/Community etc.

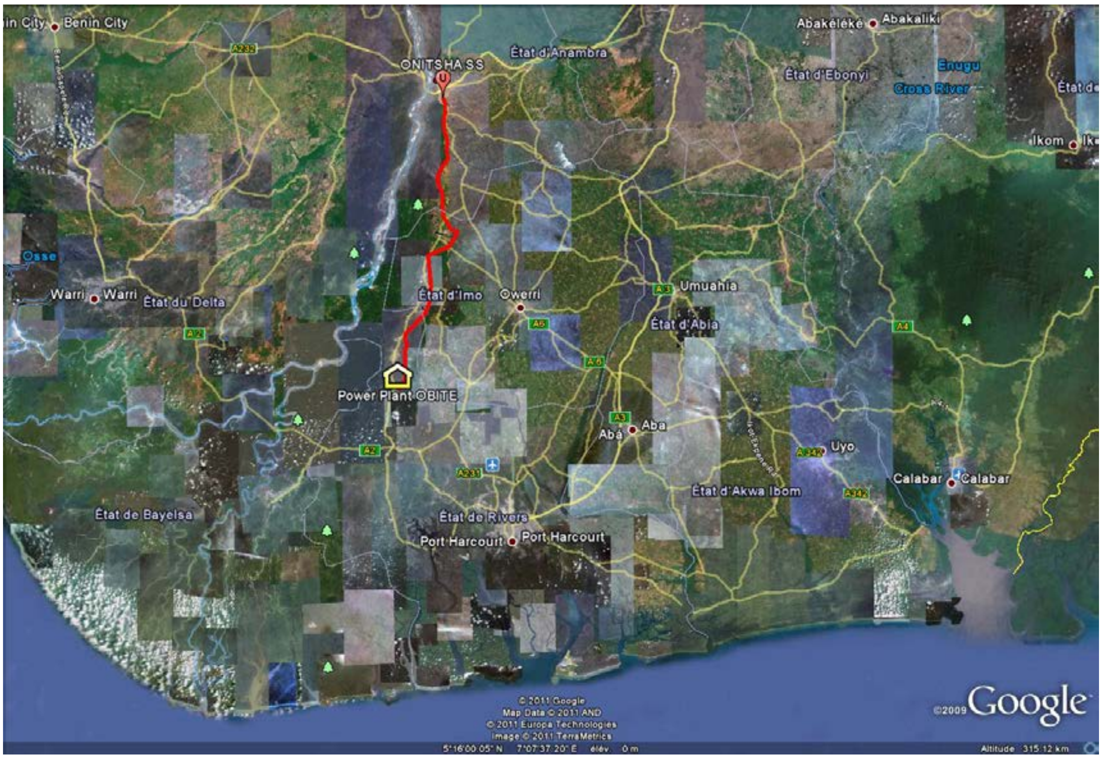
Obite/Ogbogu, Ogba/Egbema/Ndoni Local Government Area of Rivers State.

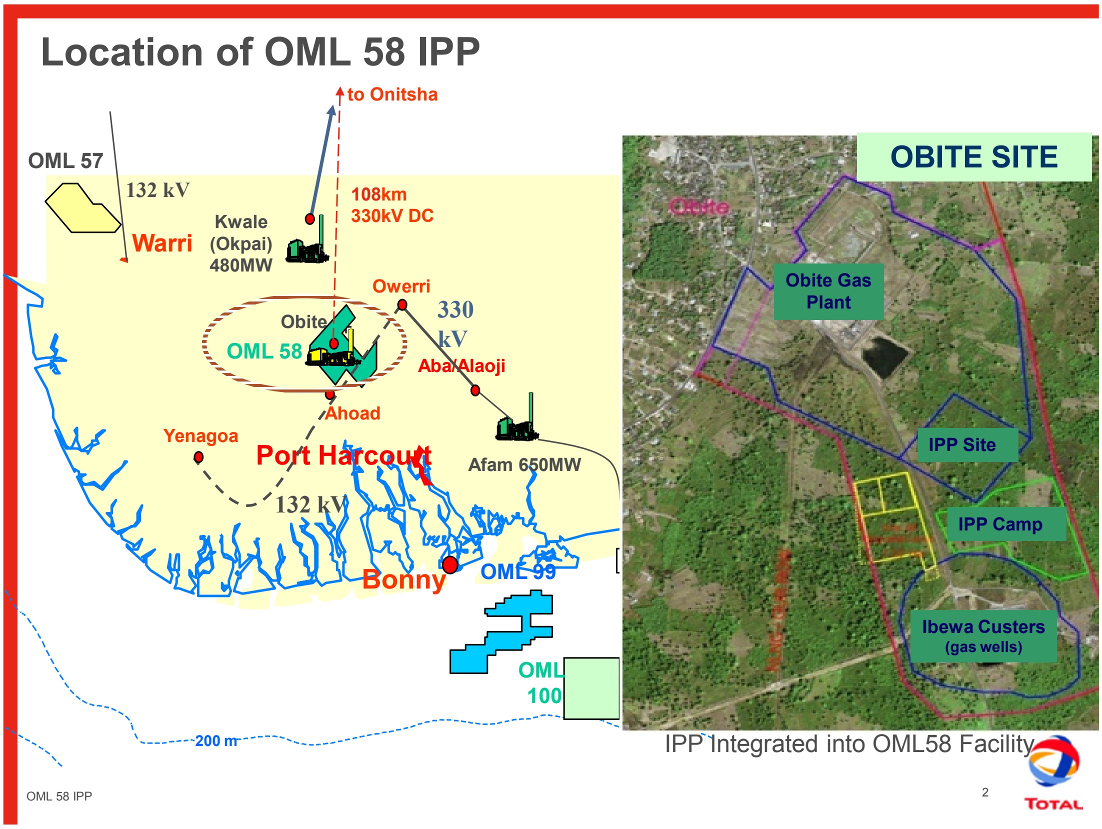
A.2.4. Physical/Geographical location

Latitude: 5°14'17.028"N, Longitude: 6°39'54.713"E

(World Geodesic System, 1984: 5°15’N and 6°40’S)

[8] USEPA, “Health Assessment Document for Diesel Engine Exhaust” May 2002, EPA/600/8-90/057F. (It should be recognized that the USEPA study is for the United States which strict standards on both quality of diesel consumed and emissions permitted, implying that the health effects in Nigeria are appreciably greater.)


Benin City
ONITSHA SS
État d'Anambra
Abakaliki
État d'Ebonyi
Enugu
Cross River
Warri
État du Delta
État d'Imo
Owerri
Umuahia
État d'Abia
Power Plant OBITE
Aba
Uyo
Calabar
État d'Akwa Ibom
État de Bayelsa
État de Rivers
Port Harcourt
Google


Location of OML 58 IPP
to Onitsha
OML 57
132 kV
Warri
Kwale
(Okpai)
480MW
108km
330kV DC
Owerri
330
kV
Obite
OML 58
Aba/Alaoji
Ahoad
Yenagoa
Port Harcourt
Afam 650MW
132 kV
Bonny
OML 99
OML
100
200 m
OBITE SITE
Obite Gas
Plant
IPP Site
IPP Camp
Ibewa Custers
(gas wells)
IPP Integrated into OML58 Facility
OML 58 IPP
2
TOTAL

A.3. Technologies and/or measures

From a technology perspective, the project activity is an IPP employing a CCGT design configuration consisting of two gas turbines and one steam turbine with a total design capacity of 428 MW. The major components are shown below as follows:

Technical data	Values:	*Source*
Total installed capacity	428 MW	*EPC Contract (Appendix H)*
Auxiliary requirements	11 MW	***EPC Contract (Appendix H)***
Capacity after auxiliary requirements	417 MW	***EPC Contract (Appendix H)***
Design Efficiency	49.1% New & Clean	*EPC Contract (Appendix H)*
Project Lifetime	20 years	*Maximum lifetime as per Guidelines on the Assessment of Investment Analysis**
Net thermal efficiency (LHV)	48% **	*TOTAL*
Plant availability factor	90%	*TOTAL*
Dispatch factor	70%	*TOTAL*
Net power generation	2,243 GWh/yr	*Calculation (avg. of first 10 full years of operation)*

* TOTAL considers the economical and physical lifetime to both be 20 years.

** Net thermal efficiency is the design level and the net efficiency during operation is 46.9%

The combustor is fired with natural gas and produces hot, high pressure, low NO_x gases, which expand in the gas turbine. The gas turbine drives the generator at one end, and an axial compressor at the other end, which supplies compressed ambient air to the combustor. The thermal energy contained in the high temperature exit gases of the gas turbine is recovered in the heat recovery steam generator, HRSG, which is designed to maximize the heat recovery of gases and allows a minimum stack temperature of the exhaust gases. The steam generated from the HRSG will be introduced to and expand in the steam turbine to drive the generator. Specific requirements are as follows:

CCGT Equipment	Description	Efficiency	Design Lifetime
2 gas turbines	Capacity of one GT in Open Cycle of 144.7 MW	34.5 %	30 years (EPC App H)
2 dual pressure heat recovery steam generator	Of vertical/horizontal design, with HP and LP drums	78% (efficiency of boiler = (inlet heat –outlet heat) / (inlet heat))	30 years (EPC App H)
1 condensing steam turbine	1x 127MW LP indoor Unit(5 stage)	Isentropic efficiency 88%	30 years (EPC App H)
1 air-cooled condenser.	Carbon Steel hot-dip Galvanised Equipment with 2x 100% condenser vac pumps and 2 drain Pumps	Vendor not yet selected	30 years (EPC App B)

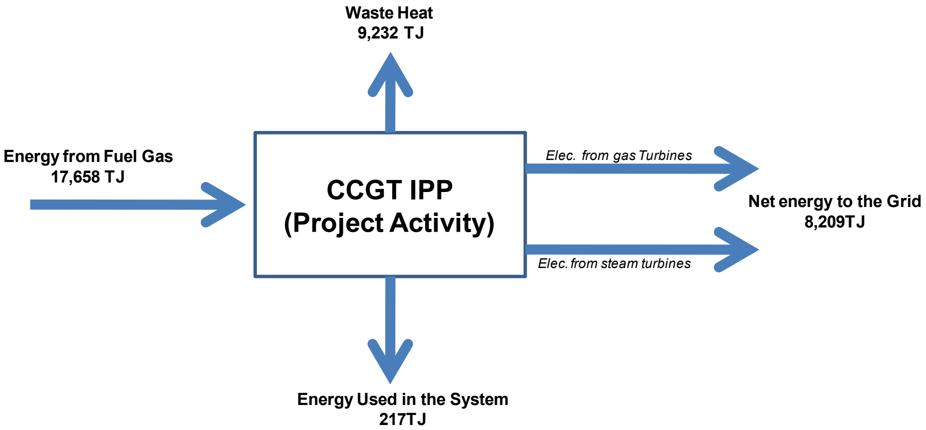
Monitoring Equipment	Description	Referenced doc
Gas flow meter	2x 100% meters Design condition for 2GTs	GS-GE-POW004 Balance of Plant Specification (22/1/09)
Diesel flow meter	1 x 100% meter Max. 100 m^3/hr	Not yet specified
Electricity meter	110V,50Hz, 2000/1A	GS-GE-POW009 330kV substation
Gas Chromatograph	Daniel Danalyzer Model 700 or equivalent	GS-GE-POW004 Balance of Plant Specification (22/1/09

All monitoring equipment will be maintained for the lifetime of the project activity. The specific monitoring points are shown in Figure 2 in Section B.3.

A water plant producing demineralised water to supply the boiler consumption and other cycle equipment complying with the minimum water quality requirements will be installed.

The project activity will be connected to the Nigerian national grid at Onitsha substation, via a new 108 km long 330 kV double circuit steel tower transmission line.

Figure 1 Energy Balance



Note: Based on estimated average operating efficiency

Energy figures are based on estimates to show the amount of energy required to produce the required electricity, energy consumed by the system and amount of energy wasted as heat.

While significant oil and gas infrastructure exists on OML58, no technology related to a grid connected IPP exists nor is there any infrastructure related to the baseline scenario (as defined in B.4).

Technology and Know-How Transfer

The use of CCGT is relatively rare in Nigeria, and the implementation of this project will represent an important transfer of technology. As a long-term investor in Nigeria and in accordance with domestic laws and regulations, TEPNG will assure appropriate training of local staff to meet its corporate operating and business requirements at the IPP. TEPNG will assure the building of local competence, know-how, and the greatest possible operational responsibility for the national labour force.

A.4. Parties and project participants

Party involved (host) indicates a host Party	Private and/or public entity(ies) project participants (as applicable)	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
Federal Republic of Nigeria	• Nigerian National Petroleum Corporation • Total E & P Nigeria, Limited	No

The OML58 block is a Joint Venture (JV) owned 60% by NNPC and 40% by TEPNG (operator). TEPNG as operator has the primary responsibility for the analysis of investments on the block which are then agreed with its JV partner, the NNPC. All investments on the block are on a 60/40% split as specified in the JV agreement. The JV itself is an unincorporated entity. TEPNG is a privately owned company (a fully owned subsidiary of TOTAL S.A)[9] while NNPC is a Nigerian state owned corporation

A.5. Public funding of project activity

There is no public funding for the project.

SECTION B. Application of selected approved baseline and monitoring methodology

B.1. Reference of methodology

The following documents are utilized in preparing this PDD:

a. Methodology: AM0029 "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas" (Version 03, Sectoral Scope: 01);
b. Tool for the demonstration and assessment of additionality (Version 07.0.0);
c. Tool to calculate the emission factor for an electricity system (Version 04.0).

B.2. Applicability of methodology

The selected CDM methodology is applicable to project activities, which meet the following applicability conditions as specified in the methodology:

1. The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant;

[9] In the PDD, TEPNG and TOTAL are used interchangeably when indicating that the data is provided for a TOTAL SA source, including TEPNG

2. The geographical/physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available;
3. Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity.

Applicability Criteria	Project activity situation
1. The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant	The project activity is the construction of a new IPP gas fired combined cycle gas turbine power facility. No grid connected IPP has ever existed on this site. Natural gas shall be the primary fuel (no back-up fuel capacity will exist) and this will be supplied from gas wells at OML58 field. Condition met.
2. The geographical/physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available.	The proposed project activity will supply electricity to the national grid in Nigeria through the transmission network at Onitsha, the closest sub-station to the project site with a suitable connection. Nigeria national grid is a closed system and represents the boundary of the baseline grid. The information concerning the grid is available from the relevant electricity authorities in the country. Condition met.
3. Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity.	Natural gas is abundant in Nigeria and reserves far exceed domestic demand needs. Additionally sufficient natural gas production is available at the location where the project is to be sited. Condition met.

The OML58 IPP Gas Fired Generation Project meets the above mentioned applicability conditions for the following reasons:

1. The project activity is the construction and operation of a new CCGT power plant (i.e. applicable with condition 1). The CCGT shall have a capacity of 428 MW and shall use natural gas as fuel. The implementation and commissioning of the plant is such that it shall start operation in an open cycle mode for 9 months during which the installation of the heat recovery system and steam turbine shall be completed and then run in a combined cycle mode. The power plant shall solely run on natural gas. There will not be any alternative fuels for the CCGT.

2. The geographical/physical boundaries of the baseline grid can be clearly identified. According to guidelines of "Tool to calculate emission factor for an electricity system", the baseline grid boundary is identified as the national electricity grid of the Federal Republic of Nigeria. The national grid consists of gas and hydro power plants all within the country with no importation of electricity. Required information on the grid needed for estimating baseline emissions - emission factor of the baseline grid in accordance with the guidelines of the "Tool to calculate emission factor for an electricity system" is publicly available at the office of Nigeria Electricity Regulatory Commission, Nigeria Transmission and Systems Operator and others.

3. Natural gas is sufficiently available in the country. According to the recent survey by EIA (August 2011), Nigeria has the 9th largest proven gas reserves in the world and the largest in Africa, with 187 trillion cubic feet (tcf) of proven high grade natural gas. In 2009, Nigeria

produced about 820 bcf of marketed natural gas which implies that the country has over 200 years of available gas supply.

Concerning the specific location of the IPP, sufficient natural gas reserves and production capacity exists on Block 58 to provide all necessary gas to the project activity. Indeed the gas production capacity has recently been substantially augmented.

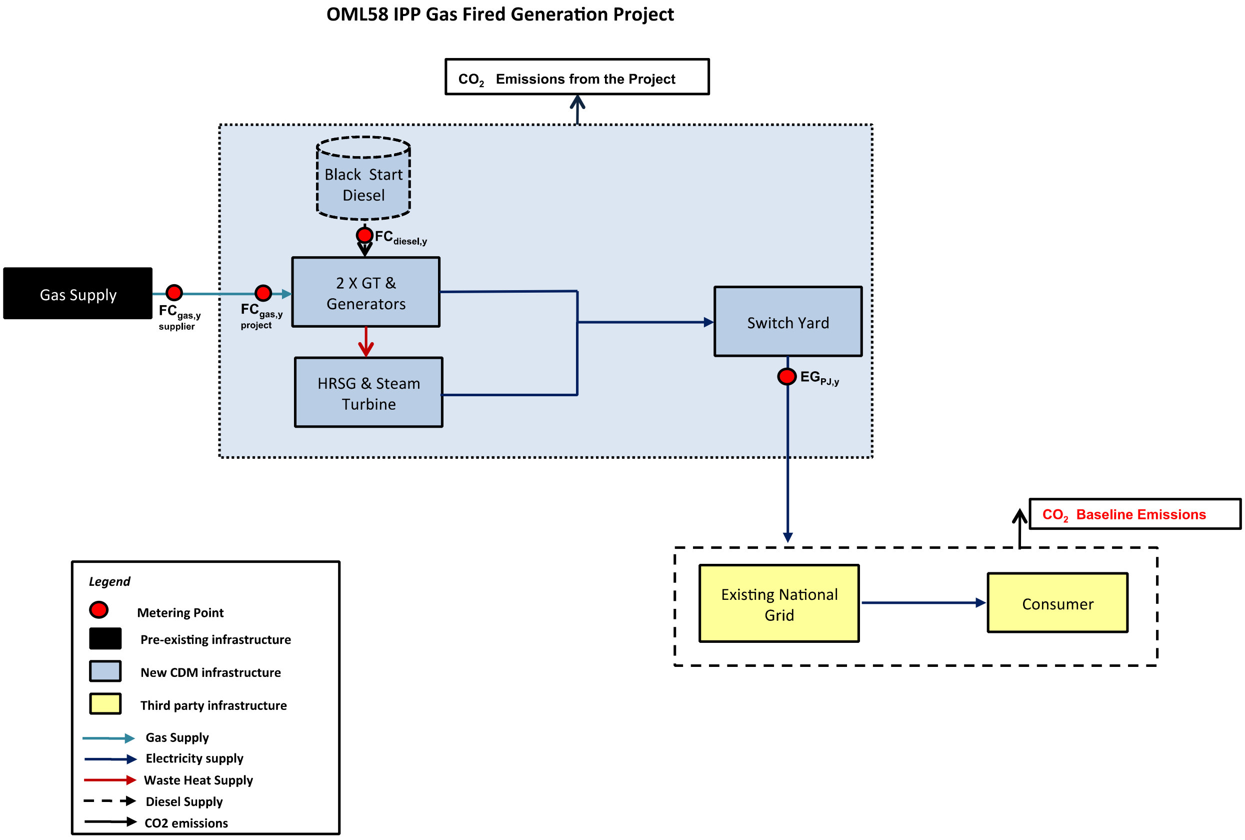
The project fits the Sector 1 Energy industries (renewable - / non-renewable sources) classification.

B.3. Project boundary

Table 1: Overview of emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Emission Factor as Calculated from the "Tool"	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification. This is conservative.
		N_2O	No	Excluded for simplification. This is conservative.
Project Activity	On-site gas combustion for fuel in IPP	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification
		N_2O	No	Excluded for simplification.
	Diesel for black-start at IPP	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification
		N_2O	No	Excluded for simplification.

Figure 2: Schematic of the Project Activity Showing Project Boundary and Monitoring Points



B.4. Establishment and description of baseline scenario

In accordance with AM0029 version 03, the following steps are used to define the baseline scenario:

Step 1: Identify plausible baseline scenarios
Step 2: Identify the economically most attractive baseline scenario alternative

The analysis undertaken in relation to these steps is presented below. As "Steps" are designated both in the AM00029 Vers 3 Methodology and in "Tool for the demonstration and assessment of additionality Version 07.0.0 for clarity when the step is from the Methodology it is labelled (M) and (T) when it is from the Tool.

Step 1: Identify Plausible Baseline Scenarios (M)

As per the methodology, identification of alternative baseline scenarios should include all possible realistic and credible alternatives that provide outputs or services comparable with the proposed CDM project activity (including the proposed project activity without CDM benefits), i.e. all types of power plants that could be constructed as alternatives to the project activity within the grid boundary[10].The grid boundary is defined as the Nigerian national grid as per the "Tool to calculate emission factor for an electricity system". Therefore, the following generic alternatives have been assessed:

- The project activity not implemented as a CDM project (i.e. CCGT);
- Power generation using natural gas, but technologies other than the project activity (i.e. OCGT);
- Power generation technologies using energy sources other than natural gas (i.e. coal-fired power generation, oil-fired power generation, hydropower, wind, solar, other renewables and nuclear);
- Import of electricity from connected grids, including the possibility of new interconnections.

Step 1: Identification of alternatives to the project activity consistent with current laws and regulations (T)

Step 1a: Define alternatives to the project activity (T)

A total of nine alternative types of power plants is presented in **Table 2** and have been assessed to *"ensure that all relevant power plant technologies that have recently been constructed or are under construction or are being planned (e.g. documented in official power expansion plans) are included as plausible alternatives"* as required in the methodology.

From the nine alternatives, plausible baseline scenarios have been identified using the following criteria:

Criteria i. *Is the alternative in compliance with all applicable legal and regulatory requirements?*

Plausible options should be in compliance with the state and national policies relating to power generation and distribution.

Criteria ii. *Can the alternative be considered "realistic and credible"?*

[10] These alternatives need not consist solely of power plants of the same capacity, load factor and operational characteristics (i.e. several smaller plants, or the share of a larger plant may be a reasonable alternative to the project activity), however they should deliver similar services.

Alternatives considered "realistic and credible" include alternative power generation or transmission technologies, which are prevailing, have been constructed, are under construction or are being planned within the grid boundary.

Criteria iii. *Can the alternative provide outputs or services comparable with the proposed CDM project activity*

Alternatives that can deliver outputs or services comparable to the CDM project activity include those that provide similar opportunities for central dispatching and load management, e.g. in terms of available capacity and power quality (reliability).

For completeness, the alternatives listed include those normally viable on a global context; however Nigeria has many country specific resources and barriers that strongly influence the choice of technology. First, the country's abundant and underutilized natural gas makes gas (when it can be connected by pipeline) the most economic of all fossil fuels for electricity generation. Second, the poor state of the grid makes the utilization of renewable energy sources almost impossible to connect into the grid.

Table 2: Consideration of alternative baseline scenario options

Scenario Description:	**Criteria i:** Compliance with legal and regulatory requirements?	**Criteria ii:** Realistic and credible?	**Criteria iii:** Provide comparable services?	**Conclusion:** Can the alternative be considered a plausible baseline scenario alternative?
Alternative 1: Project activity not implemented as a CDM project				
Natural gas power generation using combined cycle (CCGT) technology without CDM Efficiency: 47-48% Lifetime: 20+ years	Yes	Yes, there are other CCGT projects operating in Nigeria	Yes	Plausible baseline scenario alternative
Alternative 2: Power generation using natural gas, but technologies other than the project activity				
Natural gas power generation using open cycle (OCGT) technology Efficiency: 32-33% Lifetime: 20+ years	Yes	Yes, OCGT is the prevailing generation technology in Nigeria.	Yes	Plausible baseline scenario alternative
Alternative 3: Power generation using coal				
Coal-fired power generation Efficiency: 36-40% Lifetime: 20-30 years	Uncertain (issues related to EIA approval could be raised)	Unknown. Feed-in tariffs introduced in new MYTO (1 June 2012) No coal power plant is operating in the country nor is any under construction	Yes	Not a plausible baseline scenario alternative
Alternative 4: Power generation using oil (e.g. diesel/HFO)				
Oil-fired power generation using conventional steam cycle (i.e. with combined installed generation capacity comparable to the project activity) Efficiency: 36-40% Lifetime: 20-30 years	Yes	No. Diesel is a high-cost fuel and is not used or considered for large-scale grid power plants in Nigeria[11]. NERC excludes diesel/HFO from regulated tariffs.	Uncertain (would tend to be much lower capacity.)	Not a plausible baseline scenario alternative
Alternative 5: Power generation using hydropower				
Large-scale hydropower plant or multiple small-scale hydro plants (i.e. with combined installed	Yes	Large-scale: Uncertain Small-scale: Unknown	Large-scale: No Small-scale: No	Not a plausible baseline scenario alternative

[11] Diesel is extensively used for small-scale generation in Nigeria, primarily off-grid. This is due to the technology being appropriate for small generators and the logistical advantages of distributing diesel to small residential and commercial users. Diesel is a high-cost fuel and is not used for large-scale power plants either in Nigeria or globally. Insufficient Nigerian oil refining capacity means that refined products (e.g. diesel/HFO) are imported at higher cost compared to alternative domestic fuels.

generation capacity comparable to the project activity) Lifetime: >50 years				
Alternative 6: Power generation using wind				
Large-scale land mounted wind power plant (i.e. with combined installed generation capacity comparable to the project activity) Lifetime: 15-20 years	Yes	Unknown. Feed-in tariff introduced in new MYTO (1 June 2012), but wind resources are limited.	No. Would not provide similar services as the project activity (intermittency and low load factor).	Not a plausible baseline scenario alternative
Alternative 7: Power generation using other renewable energy sources				
Multiple small-scale biomass, wind, solar, tidal or wave power plants(i.e. with combined installed generation capacity comparable to the project activity) Lifetime: 20 years	Yes	Unknown. Feed-in tariffs for biomass, solar and wind introduced in new MYTO (1 June 2012)	No. Would not provide similar services as the project activity (intermittency and low load factor)[12].	Not a plausible baseline scenario alternative
Alternative 8: Power generation using nuclear				
Nuclear power generation Efficiency: 30% Lifetime: 40 years	No. Not clear how nuclear would fit in the elec. sector reform, or if private investment would be allowed. Significant EIA and security issues would need to be resolved[13]	No. There are no existing nuclear power plants in Nigeria, and the national nuclear policy is unresolved.	Yes	Not a plausible baseline scenario alternative
Alternative 9: Import of electricity from connected grids, including new interconnections				
Import of electricity from connected grids, including new interconnections with Benin, Niger, Chad or Cameroon.	Unknown. Nigeria does not currently import electricity.	No. The Nigerian grid is self-contained, and there are no plans for new connections	Unknown.	Not a plausible baseline scenario alternative

All technologies in use or under construction are included in these alternatives (see lists of power plants in the Common Practice Analysis section for plant specific detail).

Alternative 1: Project activity not implemented as a CDM project

The activity undertaken without CDM represents a plausible alternative. As shown in the Common Practice analysis, Step 4, CCGT is not the common practice in the country, but technically the construction of a CCGT is possible and two such facilities are in operation.

This is a plausible alternative.

Alternative 2: Power generation using natural gas, but technologies other than the project activity

The prevailing generation technology in Nigeria for natural gas power generation is using open cycle (OCGT) technology. According to the Nigerian Electrical Regulatory Commission's official Multi-Year Tariff Order (MYTO), "*Most new power stations completed or under construction are currently open cycle gas turbines. Given the current price of gas used for electricity generation in Nigeria, this form of generation technology produces electricity at a lower life cycle cost than combined-- cycle gas turbines, and at a lower cost than coal--fired generation*".[14] As is shown in the Common Practice Section, OCGT is the prevalent technology both for existing and under-construction power plants.

[12]While biomass sources exist, reliable biomass fuel supply chains are not developed in Nigeria. Solar and wind are not commercially used, except for very small-scale use of solar panels. A disadvantage of the use of these renewable energy sources is the intermittent nature of electricity supplies. The grid network in Nigeria has a poor dispatch system because there is insufficient generation to meet consumer demand.

[13]Nuclear is not included in Presidential Roadmap on Power

[14] Multi-Year Tariff Order (MYTO) for the determination of the cost of electricity generation for the period 1 June 2012 to 31 May 2017, Nigerian Electricity Regulatory Commission 1st June 2012

In addition it should be noted that all power plants currently under construction are OCGT (See Table 3).

Table 3: New power plants under construction in Nigeria (as of Sept. 2012)

Power Plant	Fuel Type	Technology	Capacity (MW)
Calabar	Natural gas	Open Cycle	561
Egbema	Natural gas	Open Cycle	338
Ihovbor	Natural gas	Open Cycle	450
Geregu 2	Natural gas	Open Cycle	434
Omotosho 2	Natural gas	Open Cycle	450

Source: Nigeria Independent Power Producers (NIPP), op cite

This is a plausible alternative.

Alternative 3: Power generation using coal

Substantial low-grade coal reserves exist in Nigeria and this was prominently used in the country from 1906 till early 1960s' when crude oil was discovered. The coal contribution to the commercial energy in the country in 1958/59 was recorded at about 70% but this fell to less than 0.02% in 2001 (National Energy Policy, 2003). A feed-in tariff based on the Long Run Marginal Cost of a coal generation plant in Nigeria was introduced by NERC 1 June 2012. This is *"aimed at taking advantage of the abundant coal resources in the country, and also opening up the market to give investors in power generation more choices"* (see Section 4.3 of the "Nigerian Electricity Generation Charges Multi-Year Tariff Order, 2012"). However, to revive the coal industry in Nigeria will need major commitments from the government and private sector. According to the National Energy Policy drafted for the country, it was stated clearly that the coal industry faces numerous challenges, which need to be fixed before it could be exploited for power generation (National Energy Policy, 2003). There are other logistical challenges related to domestic transport of coal as Nigeria lacks an integrated transport system and a functioning rail system.

While no studies exist for Nigeria, the US EIA's most recent cost estimates of the various capital and operating costs for electricity generation show that coal is much more expensive than natural gas on a per kWh basis, confirming that gas is preferred on an investment basis.[15]

This is not a plausible alternative.

Alternative 4: Power generation using oil (e.g. heavy fuel oil)

Oil as a fuel for electricity generation has been reduced to a minimum in most countries as the cost vis-à-vis coal and gas have reduced its economic attractiveness and it is essentially moribund as a fuel used for base electricity generation.[16]

Given that the international price of fuel oil is more than $20/mmbtu[17], a level 10-20 times that of the Nigerian domestic natural gas price and that Nigeria is a net importer of petroleum products, there does not appear to be any economic rationale for building an oil fired power plant in Nigeria.

This is not a plausible alternative.

[15] US Energy Information Agency "Updated Capital Cost Estimates for Electricity Generation Plants",November 2010, page 7 http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf
[16] International Energy Agency, "Fossil Fuel Fired Power Generation", 2007. Table 21, page 141 http://www.iea.org/publications/freepublications/publication/fossil_fuel_fired.pdf
[17] Based on early October 2012 spot prices of No. 2 heating oil in NY Harbor , http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm

Alternative 5: Power generation using hydropower

The Presidential Road Map on Power does not envision any new hydro facilities in the mid-term (only renovations of existing facilities). There is the possibility of a very large hydro-facility (2600 MW) at Mambilla and one at Zungeru (700MW) in the long-term; but this is not compatible with the scale of this project activity. As hydro is not the priority, no tariff structure is provided for new Entrants Large Hydro Plants in the new MYTO (1 June 2012) (tariffs are only provided for Successor Large Hydro Plants and small-scale hydro plants).

This is not a plausible alternative.

Alternative 6: Power generation using wind

While power generation from renewable sources is recognised by the Nigerian electricity regulatory commission (NERC), it has a cap of 10 percent of total generation between 2012-2016. However, the construction and operations of renewable energy power plants in Nigeria will require better grid system than the existing radial grid network which is usually characterized by system collapse (See annual technical report by PHCN, NCC). Also, the wind regime in Nigeria is barely good enough to generate power into the Nigerian grid. Wind speeds in Nigeria range between 2 - 4m/s[18].

Power generation from wind energy cannot be used as base load as it is intermittent and has a low load factor compared to other technologies[19]. The Nigerian electricity situation is such that more steady base load capacity is needed in the short term to solve the power supply problems.

This is not a plausible alternative.

Alternative 7: Power generation using other renewable energy source

While this option is good for localised embedded electricity generation, it is not comparable with the project activity. The project activity provides base load power while renewable energy technologies by nature provide intermittent power supply[20]. Further the poor condition of the Nigerian grid makes management of any such intermittent power sources problematic. This is not a viable alternative to a large, base-load thermal plant.

This is not a plausible alternative.

Alternative 8: Power generation using nuclear

No nuclear is currently contained in the Presidential Road Map on Power, and NERC has no provisions for nuclear power tariffs.

This is not a plausible alternative.

Alternative 9: Import of electricity from connected grids, including new interconnections

[18] Adaramola, A.S & Oyewola, O.M. (2011).*Wind speed distribution and characteristics in Nigeria.* ARPN Journal of Engineering and Applied Sciences, **6**, (2), 1.
[19] Wind energy. http://www.bwea.com/energy/rely.html
[20] Gull, T & Stenzel, T. (2005) *Variability of Wind Power and other Renewables: Management Options and Strategies*. Paris: International Energy Agency

There are no connections for importation of electricity in Nigeria. The only electricity link is for power export to the republic of Niger via a 132 kV interconnector which was built in 1976[21]. Electricity generated from hydro power plants in north central part of the country has been exported to Niger over the past decade due to the agreement signed between the two countries related to the hydro power plant. There is also a connection via a 330kV interconnector in 2007 from the Ikeja west regional control centre through Sakete for export of electricity to the Republic of Benin[22]. Nigeria has never imported power, and there are no plans for import interconnections as there are abundant energy resources domestically unutilized.

This is not a plausible alternative.

Outcome of Step 1a: Only Alternative 1 and Alternative 2 are considered to be viable base load grid connected IPP options. Both alternatives provide comparable services in terms of reliable base load power to the grid from technologies currently viable in Nigeria. The specific technical parameters of the two alternatives are shown in Table 4.

Step 1b: Consistency with mandatory applicable laws and regulations (M)

The Electric Power Sector Reform (EPSR) Act of 2005 provides the legal and regulatory framework for the electricity supply industry in Nigeria. The Act empowers the Nigerian Electricity Regulatory Commission (NERC) to regulate the electricity sector in the country, including Generation, Transmission, System Operations and Distribution.

The establishment of the Nigerian Electricity Regulatory Commission (NERC) was the direct result of a genuine desire to transform the electricity supply industry in the country into a market-based industry in line with the government's reform agenda for the country's economic, industrial and social development. Thus, the Nigerian Electricity Regulatory Commission (NERC) was established to facilitate the introduction and management of competition in the country's electricity supply industry.
In Nigeria, electricity prices are generally lower than the production cost. The tariff prior to 2000 was at an average of Naira (N) 4.50/kWh and thereafter was reviewed upward to N6/kWh where it remained until 2008 when the concept of multiyear tariff order (MYTO) was introduced by the commission responsible for electricity regulation.[23]

The 2008 MYTO which fixes the retail price at N8/kWh was based on the new entrant cost profile for generation companies and the building block approach to electricity pricing of transmission and distribution services, all based upon a set of pricing principles and cost assumptions. The ultimate objective is to provide the industry with a stable and cost reflective pricing structure that provides a reasonable return on investment to efficient industry operators. At the same time the tariff will protect consumers against excessive pricing, since the price is set at the entry level of the most efficient generation company.

A major review and overhaul of all the assumptions was carried out in the MYTO II after evaluating the existing models afforded stakeholders the opportunity to evaluate the methodology and inputs to the existing model and allowed private investors to be informed of the decision to review the MYTO I tariff.[24] The MYTO is neutral in the sense that the policy does not give a

[21] http://www.mbendi.com/indy/powr/af/ng/p0005.htm
[22] http://www.ecowapp.org/?page_id=364
[23] NERC 2008, Multi-Year Tariff Order (MYTO) For the Determination of Charges and Tariffs for Electricity Generation, Transmission and Retail Tariffs for the Period (1 July 2008 to 30 June 2013), pages 2-3

[24] NERC "2012 Mult-year Tatiff Order (MYTO) for the Determination of the Cost of the Electricity Sold by Distribution/Retail Companies for the Period 1 June 2012 to 31 May 2017, page 15

comparative advantage to more emissions-intensive technologies/ fuels over less emissions-intensive technologies/ fuels. MYTO encourages increased efficiency (reduced losses) in the transmission and distribution sectors.

NERC regulations allow both OCGT and CCGT power plants to be built in the country, and both types currently operate.

Outcome of Step 1b: Alternatives 1 and 2 are permitted

Outcome of Step 1: Based on the above analysis, the following alternatives are identified as plausible baseline scenarios:

Alternative 1: Project activity not implemented as a CDM project
Alternative 2: Power generation from natural gas using OCGT technology

These alternatives are analysed further in Step 2 below.

Step 2: Identify the economically most attractive Baseline Scenario Alternative (M)

Step 2: Investment analysis (T)

The economically most attractive baseline scenario alternative is identified using standard investment analysis to calculate the Project Internal Rate of Return after tax in current US$ (IRR RT after tax) for the plausible alternatives identified in Step 1. IRR RT after tax is a commonly used financial indicator when assessing project investment opportunities, and follows CDM guidance.

From a technical perspective, the project developer prefers the CCGT option as it fits more clearly within the overall corporate objectives on energy efficiency and environmental sustainability. The barrier was that of assuring that the economic returns were sufficient to justify the investment. As the methodology clearly states in considering alternatives the alternative need not be built by the proponent of this specific project activity:

> "…may not be available to project participants, but could be to other stakeholders within the grid boundary."

NERC on 1 June 2012 published the Multi-Year Tariff Order 2 (MYTO 2), which establishes the regulated prices to be paid to licensed electricity generation companies in providing electricity to distribution and retailing companies for the period 1st June 2012 to 31st May 2017. MYTO is based on the new entrant cost profile for generation companies and is a result of a comprehensive review and overhaul of all the assumptions behind the regulated wholesale prices for electricity between September 2010 and May 2012. Tariffs presented in MYTO 2 are intended to be cost reflective and provide financial incentives for urgently-needed increased investments in the industry. In Section 3 of the "Nigerian Electricity Generation Charges Multi-Year Tariff Order, 2012"[25], NERC describe the following:

> *"For the time being, the NERC has determined that the lowest cost new entrant generator is an open-cycle gas turbine (OCGT) using natural gas. Most new power stations completed or under construction are currently open cycle gas turbines. Given the current price of gas used for electricity generation in Nigeria, this form of generation technology produces electricity at a lower life cycle cost than combined-cycle gas turbines, and at a lower cost than coal-fired generation. However, it is anticipated that the gas price will become market-based in the near future, and CCGT is likely to emerge as the benchmark for a lowest-cost*

[25] See document "2012 MYTO for Generation" available at http://nercng.org/index.php/document-library/func-startdown/67/

new entrant generator. Then, the NERC will review the generation pricing methodology accordingly." (NERC, 2012)

As OCGT is the most common power plant technology in the country and forms the basis for NERC's tariff calculations, it is clearly a valid alternative from a national sectoral perspective. In determining the technical and economic parameters for OCGT, a standard "new entrant" power plant was developed by NERC (with support from the World Bank) and is used as the basis for tariff design and in estimating the IRR RT for a new entrant using this technology. This "new entrant" is defined as a 250 MW OCGT power plant and is fully described in the Multi Year Tariff Order model (published on the NERC website). A series of public consultations with stakeholders were conducted to vet the MYTO model. Therefore the most viable and transparent OCGT option is the new entrant 250 MW OCGT and this is used as the example for Alternative 2. The technical and economic parameters are taken directly from the MYTO 2 model for a "new entrant."

Table 4 shows the key parameters of the two plausible alternatives. The data for Alternative 1 is developed by the project developer, while that for Alternative 2 is NERC's new entrant standard.

Table 4: Key technical and financial assumptions for Alternative 1 and 2

Assumptions [notes] *Note: Annual values are presented for year 2016*	**Alternative 1:** CCGT power plant [1]		**Alternative 2:** OCGT power plant [2]	
Technical data	**Values:**	***Units:***	**Values:**	***Units:***
Total installed capacity	428	*MW*	250	*MW*
Project lifetime	20	*Years*	20	*Years*
Net efficiency (LHV) (during operation)	46.9	*%*	32	*%*
Investment costs	**Values:**	***Units:***	**Values:**	***Units:***
CAPEX (per kW installed)	[redacted]	*US$/kW*	979	*US$/kW*
Operating costs	**Values:**	***Units:***	**Values:**	***Units:***
Operating Cost per kWh	[redacted]	*US$/kWh*	7.89	*US$/kWh*
Fiscal regime	*AGFA [3]*		*CITA [4]*	
Financial performance	**Values:**	***Units:***	**Values:**	***Units:***
IRR RT real after tax , (excluding CERs)	[redacted]	*%*	13.5	*%*

[1] The financial performance for Alternative 1 is calculated based on the Project Proponent's internal economic model at the time of the investment decision and the CDM "Guidelines on the Assessment of Investment Analysis." The model has been provided to the DOE for validation.
[2] The financial performance for Alternative 2 is calculated using the MYTO II Excel model developed by NERC *("NERC MYTO 010612.xlsm"* downloaded on 29/10/12 and has been provided to the DOE. The model can be accessed on the NERC website, nercng.org
[3] Associated Gas Framework Agreement (AGFA) The fiscal regime appropriate for investments on Oil Mining Licences (OML)
[4] The fiscal regime (Corporate Investment Tax Act, CITA) relevant for investments in Nigeria that do not fall under special statute. (Option 3 in the MYTO model, worksheet IPP NEM View)

From the summary results provided in Table 4, it can be seen that the IRR RT after tax is significantly higher for Alternative 2 than for Alternative 1. Alternative 2 was thus selected as the most plausible baseline scenario. As required by the methodology, a sensitivity analysis has been performed in order to confirm this conclusion. The sensitivity analysis was performed by subjecting both Alternatives to potential variations in the following critical parameters:

a) Capital expenditures (CAPEX)
b) Operating costs
c) Available capacity
d) Tariff rates

The financial performance was calculated for a 10% deviation for each parameter (or time series as applicable), reflecting potential variations in these parameters during the project lifetime. The results of the sensitivity analysis are presented in the table below (values shown are IRR RT after tax):

Table 5: Sensitivity analysis

	Alternative 1	Alternative 2	Alternative 1	Alternative 2
Sensitivity a)	**10% increase**		**10% decrease**	
Capital expenditures (CAPEX)	[redacted]	11.9%	[redacted]	15.3 %
Sensitivity b)	**10% increase**		**10% decrease**	
Operating costs (OPEX)	[redacted]	13.0 %	[redacted]	13.9 %
Sensitivity c)	**10% increase**		**10% decrease**	
Available capacity	[redacted]	NA	[redacted]	NA
Sensitivity d)	**10% increase**		**10% decrease**	
Tariff rates	[redacted]	NA	[redacted]	NA

The NERC MYTO model only allows certain variables to be changed (such as CAPEX and OPEX). The available capacity is fixed vis-à-vis the installed capacity. As the model is designed to allow an investor to evaluate the returns given the tariff rate established by NERC, the operator does not have the right to independently change tariff rates and other variables that influence rates. Thus under the MYTO model, the relevant variables for sensitivities are determined by NERC. Given NERC's framework, the sensitivity analysis consistently supports (for a realistic range of assumptions) the conclusion that Alternative 2 is consistently and robustly the most economically and/or financially attractive. Therefore, it is concluded that Alternative 2 **(**power generation from natural gas using OCGT technology) represents the baseline scenario.

The analysis by the project developer (which is in accord with NERC) clearly supports the conclusion that power generation from natural gas using OCGT technology (i.e. Alternative 2) represents the baseline scenario for large-scale, base power generation in Nigeria.

B.5. Demonstration of additionality

As per AM0029, the assessment of additionality comprises the following steps:

Step 1: Benchmark investment analysis (M)
Step 2: Common practice analysis (M)
Step 3: Impact of CDM registration (M)

The assessment undertaken in relation to these steps is presented below.

Step 1: Benchmark investment analysis

The methodology requires the following sub-steps contained within the latest version of the "Tool for the demonstration and assessment of additionality":

- Sub-step 2b: Option III. Apply benchmark analysis
- Sub-step 2c: Calculation and comparison of financial indicators
- Sub-step 2d: Sensitivity analysis

The "Tool for the demonstration and assessment of additionality" version 07.0.0 has been applied for the proposed CDM project activity as described below, taking into account the "Guidance on the assessment of investment analysis" version 05.

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

The financial indicator most suitable for the project type and the decision context has been identified as the return on equity in real terms after tax (equity IRR RT after tax) as described in Tool 07.0.0..

As discussed, since 2008 the NERC has put in place and in the public domain the MYTO model in order to develop rates and facilitate investment in the electrical sector. This model provides a way for an investor to calculate the IRR of a "new entrant" IPP. While the model has been improved over time and the original tariff structure has been revised upwards (as no investments were attracted), the basic framework and key assumptions have remained constant. So it can be reasonably assumed that the IRR calculated for a "new entrant" using the MYTO model represents a benchmark for investments as per the guidance in the "Tool":

> *Government/official approved benchmark where such benchmarks are used for investment decisions* ("Tool" 07.0.0, page 10)

The real IRR as calculated in the MTYO[26] model is:

Based on MYTO Model (Option 3 for fiscal regime – Corporate Income Tax)	
Project IRR (USD) % Nominal	16.5%
Minus – Avg. USD Inflation (as shown in Model	3.0%
Real IRR; Alternative 2, OCGT based on NERC Model	13.5%

Note: See IRR, worksheet Alt 2 for Model References

This real IRR of 13.5% closely corresponds to the 13% in Appendix A of the "Guidance on the assessment of investment analysis" version 05, taking account of the relevant location (i.e. Nigeria) and project category (i.e. Group 1, comprising Sectoral Scope 1: Energy Industries).

Therefore it is determined that the default value of 13% represents a valid real IRR benchmark.

Benchmark applied: 13% (equity IRR RT after tax)

With respect to the benchmark applied, Nigeria is a challenging and expensive country in which to invest. In 2005 and 2006 due to its inability to repay its high level of debt, the Paris Club allowed Nigeria to repay its outstanding $30 billion in debt for approximately $12 billion – a 60% discount. Nigeria is rated B+/B by Standard & Poor's[27], the fourth-highest junk assessment, and B with a "stable" outlook by Fitch Ratings. Further the security situation in Nigeria with the recent bombings including in the capital of Abuja has made all investments increasingly risky and financing difficult to obtain. These difficult domestic conditions should be viewed within the context of the worldwide economic recession that has caused major reductions in financing availability; one result being a substantial reduction in Foreign Direct Investment in Nigeria[28]. Further the overall global recession has serious implications to the cost and risk of attracting investment.

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

The suitable financial indicator (i.e. equity IRR RT after tax) has been calculated for the proposed CDM project activity. As described under Sub-step 2b, the calculation of the financial indicator takes into account the specific financial/economic situation of the project participants.

[26] The analysis uses the MYTO Version 2 model. The MYTO 1 Model was made public in 2008, but in NERC's Public Notice of 11 February 2010 the Commission noted: "… due to the numerous complaints and observations… has become imperative for the Commission to conduct the major review of the MYTO." The MYTO Version 2 model was made public in 2012. Due to this version correcting and improving the MYTO model during the period of 2010-2012, Version 2 represents the most considered view of a valid IRR for an investor – both in 2010 and 2012.

[27] Eboh, M and Moshoba, O. 30th December 2011. *Nigeria: S & P upgrades Country's Credit rating* retrieved from http://allafrica.com/stories/201112300896.html on 6 Nov. 2012

[28] Sanusi, L. (2010 December). *Global Financial Meltdown and the reforms in the Nigerian banking Sector.* Paper presented by the by Governor of Central Bank of Nigeria, Retrieved from http://www.cenbank.org/out/speeches/2010/Gov_ATBU%20Convocation%20Lecture.pdf

The equity IRR RT after tax was calculated based on technical and economic assumptions resulting from a comprehensive project evaluation, based on accepted methods and principles used within TEPNG's standard investment calculation methods and specific Nigerian conditions. The economics presented in the PDD are based on the economic analysis used in the management committee meeting that approved the decision to launch the first phase of the EPC contract of the IPP and the expenditures actually recorded on 31 December 2010, the date of the signing of the EWC.

Concerning the analysis, costs and prices are treated in the relevant currency (i.e. US$ or Naira). Net annual cash flows in US$ in nominal terms are converted to 2010 US$ (real terms) prior to calculating the financial indicator. The financial indicator is calculated based on the following:

- *Project lifetime:*
  20 years (based on 20 years of CCGT operation under the term of the PPA)
- *Capital expenditures (CAPEX):*
  The capital cost of the project is based on the EPC documents that have been submitted for the IPP. The breakdown of the CAPEX amount is:

	US Millions
Project Mng, Safety, Security, Community	[redacted]
Engineering	
Procurment and Supply	
Fabrication, Construction, Installation	
Commissioning and Training	
Spare Parts	
Taxes	
TOTAL	

source: EPC Contract

- *Residual Value*
  The fair value of project activity assets is set to zero at the end of the project The maximum time of the PPA is 20 years which is the project lifetime in the investment analysis which is the maximum lifetime in the "Guidelines on the Assessment of Investment Analysis." The Niger Delta is a harsh operating environment and TEPNG will set the book lifetime at 20 years on a straight line basis, thus there will be no book value remaining at the end of the project life.

  As the Guidelines states: "not to apply a residual value would imply that the project must repay the full value of the capital expenditure" and the book value is fully depreciated at the end of the 20 year life, the residual value is set at zero.

  Operating expenditures (OPEX):
  All operating expenditures relevant to Power Plant project activity. Major components of the operating costs are contained in the Long Term Services Agreement (LTSA), which was in negotiation in 2010.

  The OPEX expenditure is divided into five basic categories and these and the annual amounts are itemized in the IRR model (sheet IRR, Alt 1).
- *Generation capacity and electricity supplies to the grid:*
  The generation capacity which can be declared available (available capacity) is determined over the lifetime of the project as a function of the installed capacity, auxiliary requirements, capacity degradation and availability. The average available capacity is estimated at 3,200 GWh/year. Supply of electricity to the grid is calculated from the annual available capacity assuming a 70% dispatch factor.

- *Tariff rates:*
  As discussed in the PDD, the electrical sector and its regulatory regime were, and continue to be, in a state of flux. Regarding the tariff structure, the tariff initially proposed under MYTO 1, was not sufficient to attract any investment, and on 11 February 2010, the NERC issued a "Public Notice of its Intent to Conduct a Major Review of MYTO." No official feedback from this review was available until NERC issued its "Consultation Paper for the 2011 Major Review of the Multi Year Tariff Order (MYTO)" in May 2011 and the revised MYTO Determination was not issued until June 1 2012.

  For the project developer this caused considerable uncertainty in forecasting the tariff it could be applicable for the IPP and yet there was considerable pressure from Nigerian authorities to move the work into the implementation stage. This is the background for the management meeting of 16 November 2010 to give approval to enter into the Early Works Contract.

  At the November meeting, the achievable tariff rate was a key component in the management decision. Important points concerning the determination of the estimated tariff rates by the project developer at the time of the investment decision included:

  - The project developer had a clear preference for CCGT, but the NERC base tariff design was based on the less costly capital (per MW) OCGT option. This put the more costly (albeit more efficient) CCGT at a disadvantage as the base tariff if unchanged would provide a lower IRR for CCGT than OCGT. It was assumed that NERC would recognize the rationale for the higher CCGT costs in future tariff discussions.

  - The OML58 IPP is to be constructed on an Oil Mining License (OML) that is ring-fenced and has specific fiscal terms – the AGFA (Associated Gas Framework Agreement.) The ability of the IPP to utilize the AGFA rather than the Companies Income Tax Act (CITA), which is the national fiscal terms used in the MYTO model, is an important variable in the decision.

  Given the sensitivity of the Nigerian government to the tariff rates (and indeed the lack of revenue and hence the need for Government subsidy in the electrical sector to pay tariffs), the project developer took the approach that in future negotiations with NERC that if the developer would be allowed to utilize the AGFA fiscal regime and the tariff could be negotiated at an IRR that the developer considered feasible.

  Therefore the tariff used in the additionality assessment is the developer's estimate of the tariff:

  - Reflects the higher costs of the CCGT will be recognized by the regulator,
  - Utilizes the AGFA tax regime
  - Set at the upper end of the IRR range that the developer considers feasible. (This being a "conservative approach" since it gives the highest possible IRR for the CCGT alternative.)

  (Given that the tariff is yet to be determined, additional confidential documentation on the tariff issued is provided to the DOE.)

- *Fiscal conditions:*
  The overall fiscal conditions are those of the Nigerian Tax Code (e.g. corporate and other tax rates, depreciation schedules, etc.). The proposed project activity is located on an operating OML, which includes specific fiscal considerations and these considerations, when appropriate, are used in calculating the project's IRR. (The relevant tax code on oil producing blocks is designated as AGFA.)

- *Financing:*
  The proposed CDM project activity is and will be financed by the JV partners (i.e. TEPNG and NNPC). As an unincorporated entity, all investments related to the project activity are funded directly by cash contributions from the JV partners. The project funding is 100% equity. External project finance is not considered.
- *Financial impacts beyond the project boundaries:*
  Oil and gas infrastructure present on OML58 which is outside the boundary of the IPP is not part of the project activity. The IPP is designed solely to provide grid-power and no economic benefits accrue to the oil and gas operations on the block due to the proposed project activity.

The project participants have supplied a spreadsheet version of the investment analysis to the DOE for review.

The JV partners will sign the Purchase Power Agreement to supply electricity to the grid and this will legally obligate them to provide sufficient gas to the project activity to meet this contractual requirement.

Based on the assumptions presented above, the selected financial indicator has been calculated for the proposed project activity (without any CER revenues). A comparison of the financial indicator with the applied benchmark is presented below:

Equity IRR RT after tax:	Benchmark applied:
[redacted]	13.0%

As the CDM project activity has a less favorable indicator than the benchmark, the CDM project activity cannot be considered as financially attractive as per the "Tool for the demonstration and assessment of additionality" version 07.0.0.

Sub-step 2d: Sensitivity analysis

The following parameters are considered critical to the economic performance of the project activity:

a) Capital expenditures (CAPEX)
b) Operating costs
c) Available capacity
d) Tariff rates

The financial indicator of the proposed CDM project activity has been calculated for a 10% deviation for each of these parameters (or time series as applicable). The results of the sensitivity analysis are presented in the table below (values shown are equity IRR RT after tax):

Table 6: Sensitivity analysis

Sensitivity a)	**10% increase**	**Base case**	**10% decrease**
Capital expenditures (CAPEX)	[redacted]	[redacted]	[redacted]
Sensitivity b)	**10% increase**	**Base case**	**10% decrease**
Operating costs	[redacted]	[redacted]	[redacted]
Sensitivity c)	**10% increase**	**Base case**	**10% decrease**
Available capacity	[redacted]	[redacted]	[redacted]
Sensitivity d)	**10% increase**	**Base case**	**10% decrease**
Tariff rates	[redacted]	[redacted]	[redacted]

The sensitivity analysis consistently supports (for a realistic range of assumptions) the conclusion that the project activity is unlikely to be financially/economically attractive. Specifically:

- CAPEX would have to decrease by more than [redacted] for the IRR to reach 13% and given that EPC contract is firm, this is not plausible.
- OPEX would have to decrease by almost [redacted] for the IRR to reach 13%, and as the OPEX costs are largely known, this is not plausible.
- Available capacity would need to increase by [redacted] for the IRR to reach 13%. A [redacted] increase in available capacity would require a different technical design and an increase in capital costs. This is not plausible.
- Tariff rates would need to increase by [redacted] for the IRR to reach 13%. Tariff rates for CCGT are negotiated and the project developers do not see this as feasible.

It should be noted that as gas prices are pass-through in the tariff design, that increases and decreases in the gas prices have no appreciable effect on the project's IRR.[29]

Based on the sensitivities presented in Table 5, the sensitivity analysis consistently supports (for a realistic range of assumptions) the conclusion that the project activity is unlikely to be financially/economically attractive

Step 2: Common practice analysis (M)

The methodology requires **Step 4** contained within the latest version of the "Tool for the demonstration and assessment of additionality" (i.e. version 07.0.0) to be applied to demonstrate that the project activity is not common practice in the relevant country and sector. According to paragraph 13 of the Tool, the measure "Switch of technology with or without change of energy source" is covered in the list of measures for which the procedure described in paragraph 57 under Step 4 in the Tool can be applied to analyse common practice. Application of CCGT technology is seen as a switch of technology with respect to power generation, and the proposed project activity is covered by the measures listed in paragraph 13.

Sub-step 4a: Analyze other activities similar to the proposed project activity (T)

Using this sub-step, two other activities are identified that currently use CCGT technology and provide electricity to the grid:

Facililty	Fuel	Commissioned	Technology	Capacity	Operator	CDM Status
Okpai	Natural Gas	2003	CCGT	480	NAOC	None
Afam 6	Natural Gas	2010	CCGT	650	SPDC	Posted for CDM Public Comment on 16/09/2012

[29] Several risks which may negatively affect the project activity are not included in the economic assessment used in the PDD (as they are so difficult to quantify): principally:

i. *Additional costs related to supply of electricity to the grid:*
The project is dependent on a new 108 km HV.. Infrastructure projects under Transmission Company of Nigeria (TCN) have frequently been subject to delays and implementation problems.[29] As a result, the JV has agreed to build the HV line on behalf of TCN which upon completion will be transferred to TCN and the costs reimbursed. Uncertainties related to this line or the reimbursement of costs have not been taken into account in the financial analysis.

ii. *Regularity of payments from the power purchaser:*
There is substantial risk to the regularity and completeness of payments by the purchasers for the electricity. In the past payments have often not been prompt or full, and indeed the economic capacity of the sector is open to doubt. This is recognized as an issue and the Federal Government and the World Bank are working to put in place a Partial Risk Guarantee to limit the risk to the generators. If implemented this will serve as a cushion, but not eliminate this risk.

Further a review of all IPPs currently under construction shows that no CCGTs are currently being implemented. (See Table 7)

As Afam 6 has been posted for public comment and is undergoing validation for CDM, it is excluded from the common practice analysis.

The result of this sub-step is that one project using the same technology has been implemented, NAOC Okpai.

Step 4b: Discuss any similar options that are occurring

NAOC's Okpai was begun in 2001 and commissioned in 2003. It was implemented before the 2005 restructuring of the Nigerian power sector and under a different regulatory/investment regime which existed at that time. (The Nigerian regulatory agency, NERC, was not established until 2005 and previously all investment was through the Ministry of Power.)[30] NAOC has never issued any public information as to the financial rationale for the power plant, but in its press release at the time placed the project within the company's larger objective of:

> *... the plan for natural gas monetization which was launched by Eni in 1999 with the objective of elimination of atmospheric emissions by 2008*[31]**.**

It has made no public mention of the financial basis of the IPP, so it is not possible to make a direct comparison with the proposed project activity. However it should be noted that NAOC has considered a second phase for Okpai that has never begun[32]. The lack of progress on this second phase implies that NAOC could have similar concerns as to the financial returns of a new investment in CCGT.

Given these reasons and the lack of any public data, the rationale behind the NAOC Okpai was in a different regulatory and investment environment is believed to be substantially different to that faced by OML58 IPP.

The step-wise procedure described in paragraph 47 in the Tool is thus applied to analyse common practice. The results of the analysis are presented below:

Step 1: Calculate applicable output range as +/-50% of the design output or capacity of the proposed project activity.

The proposed project activity consists of a CCGT plant with a gross capacity of 428 MW at site conditions. The applicable output range is thus calculated as 214 to 642 MW (i.e. +/- 50% of 428 MW).

Step 2: In the applicable geographical area, identify all plants that deliver the same output or capacity within the applicable output range, calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project. Note their number N_{all}. Registered CDM project activities and projects activities undergoing validation shall not be included in this step.

The Nigerian grid is powered mainly by natural gas and hydro. The table lists all the grid-connected power plants that have started operation before the start date of the project.

[30] Presidential Roadmap for Power Sector Reform 2010 (provided to DOE)
[31] ENI/AGIP Press Release, April 2005: http://www.eni.com/it_IT/media/comunicati-stampa/2005/04/Eni__inaugurata_oggi_la_centra_01.04.2005_1192442422160.shtml
[32] NNPC Press Release, 2010 http://napims.nnpcgroup.com/AboutUs/NAPIMSNews/tabid/245/articleType/ArticleView/articleId/246/NNPCAGIP-JV-TO-COMMENCE-2ND-PHASE-OF-KWALE-OKPAI-IPP-SOON.aspx

Table 7: All Power Plants Connected to the Nigerian National Grid[33], [34].

Power Plant Type	Power plant Name	Fuel Type	Technology	Installed Capacity (MW)	Remarks	Ownership
Hydro	Kainji	-	-	760		PHCN
	Jebba	-	-	578		PHCN
	Shiroro	-	-	600		PHCN
	Nesco*	-	-			
Thermal	Egbin	Natural Gas	Steam	1320		PHCN
	Sapele	Natural Gas	Steam	720		PHCN
	Afam 5	Natural Gas	Open Cycle	60	Afam 1-5 had a combined capacity of 516, but only Afam 5 is working. Afam 1-4 have been decommissioned. Current running capacity is 60MW.	PHCN
	Delta	Natural Gas	Open Cycle	900		
	AES	Natural Gas	Open Cycle	302		IPP
	Okpai	Natural Gas	Combined Cycle	480		IPP
	Afam6	Natural Gas	Combined Cycle	650		IPP
	Ajaokuta**	Natural Gas	Open Cycle	110	Built but never operated.	Private
	Omotosho	Natural Gas	Open Cycle	335		NIPP
	Geregu	Natural Gas	Open Cycle	414		NIPP
	Ibom	Natural Gas	Open Cycle	155		Akwa Ibom State
	Omoku	Natural Gas	Open Cycle	150		Rivers state
	Trans Amadi	Natural Gas	Open Cycle	100		Rivers state
	Olorunsogo	Natural Gas	Open Cycle	335		PHCN
	Olorunsogo II	Natural Gas	Open Cycle	250	Design is for 750 MW bout only 250 MW is implemented	NIPP
	Sapele II	Natural gas	Open Cycle	450	Commissioned	NIPP

* NESCO is a private electricity company provides and operates as an isolated system in Jos, Plateau state, Nigeria.
** Ajaokuta was built primarily to supply electricity to the Ajaokuta Steel Company with the excess being dispatched into the national grid. However, due to the non-functional state of the company, the power plant is not put to use beyond 2008.

Identified plants that meet the criteria specified in the Tool are listed in Table 7. N_{all} is seven.

Step 3: Within the plants identified in Step 2, identify those that apply technologies different to the technology applied in the proposed project activity. Note their number N_{diff}.

All power plants identified in Step 2 (N_{all}) applying a technology different to the technology applied in the proposed project activity (i.e. CCGT technology) are classified "N_{diff}" in the table below. N_{diff} equals 6.

[33] Power Holding Company of Nigeria (2011). *Generation and Transmission Grid Operations*; (Annual technical report issued by National Control Centre), Retrieved from http://nigeriasystemoperator.org/doc-lib/2009-annual-report.pdf

[34] Power plants under construction owned by the Nigeria Independent Power Producers (NIPP) also known as Niger Delta Power Holding Company (NDPHC) Retrieved from http://www.nidelpower.com/main/index.php

Table 8: Power plants in sub-set N_{all} classified as N_{diff}

Power Plant	Fuel Type	Technology	Capacity (MW)	Classification
AES	Natural Gas	Open Cycle	302	N_{diff}
Okpai	Natural Gas	Combined Cycle	480	
Omotosho	Natural Gas	Open Cycle	335	N_{diff}
Geregu	Natural Gas	Open Cycle	414	N_{diff}
Olorunsogo	Natural Gas	Open Cycle	335	N_{diff}
Olorunsogo II	Natural Gas	Open Cycle	250	N_{diff}
Sapele II	Natural Gas	Open Cycle	450	N_{diff}

Step 4: Calculate factor $F=1-N_{diff}/N_{all}$, representing the share of plants using a technology similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity.

The proposed project activity is not a "common practice" within the Nigerian power sector as none of the conditions presented in the Tool are fulfilled:

(a) The factor F is 0.14 (i.e. not greater than 0.2)[35]
(b) N_{all} - N_{diff} is 1 (i.e. not greater than 3)[36]

The conclusion is that the proposed project activity is not considered common practice as demonstrated. In addition, it is useful to note that even if power plants under construction are included[37], the common practice analysis remains valid.

The above analysis demonstrates that the project activity is not common practice in the relevant country and sector.

Step 3: Impact of CDM Registration (M)

Given the current difficult situation of the global carbon market, the impact of CDM registration in many ways relates to TEPNG and its partner NNPC's longer term view of the carbon market and that both partners wish to be pro-active in reducing GHG emissions.

The very large capital investment required for an IPP means that CER revenues contribute in a limited way to the overall economics. However as the analysis in Section B.5 shows, the difference between the project's estimated IRR and the baseline is close enough that CER revenues do provide a useful improvement in the returns. Perhaps more important than the role that CER revenues play by improving capital returns, is their ability to offset on-going operating expenses.

Operating expenses are a significant cost in power plants, and the timeliness of payments by the government owned purchaser is not known. Previously when this was done by PHCN the record was poor, and the new entity (NBET) put in its place is untested.. Indeed the poor state of so many of Nigeria's power plants reflects the financial inability to assure on-going maintenance. By providing a steady flow of hard currency, CER revenues can serve as an important cash buffer to assure that maintenance continues even if tariff revenues are delayed.

[35] F = 1 – 6/7 = 0.14
[36] N_{all} - N_{diff} = 7 – 6 = 1
[37] Including power plants currently under construction (Table 3), the analysis of common practice, the factor F is 0.08 and N_{all} - N_{diff} is 1.

There is also the intangible benefit that CDM has brought to helping to prioritize the project from an investment perspective. TOTAL S.A. has been quite pro-active with TEPNG in encouraging them to develop and implement this project with the support of the CDM given overall Company objectives of reducing GHG emissions. Likewise the Renewable Energy Division (RED) in NNPC has advocated for this project within that company. Thus the belief that CDM registration could be obtained has served to prioritize this project activity with both partners.

Start date

The start date of the project activity is prior to the date of publication of the PDD for the global stakeholder consultation. Based on the CDM definition of the start date as "the earliest date at which either the implementation or construction or real action" occurs, the appropriate start-date for this project activity is the 31/12/2010 signing of the Early Works Contract (EWC).

TOTAL as a global company is well aware of CDM and has been actively involved in CDM development for many years. Therefore CDM has always been part of the consideration in assessing the IPP options for OML58. In addition to internal discussions, TOTAL E&P made formal presentations to its partner NNPC to explain how CDM could be beneficial to the project and should be pursued. Specifically CDM as discussed in the following meetings or covered in the following actions:

- 6th November 2009 TEPNG meeting with NNPC/RED (Renewable Energy Division):
  - Update on status of TEPNGs potential CDM projects, RED acknowledged that TEPNG was doing good work on CDM
- 24th May 2010 - TEPNG meeting with NAPIMS
  - Presentation to NAPIMS of TEPNG's potential CDM projects – OML100 Flare-out and OML58 IPP
  - NAPIMS agreed to Prior Notification being given to UNFCCC for OML100 and OML58 IPP projects
  - Follow-up meeting required at which CDM project development strategy will be agreed
- 15th September 2010 – Gas Business Workshop with NNPC/NAPIMS
  - Update of CDM activities – Prior Notification forms for OML100 and OML58 IPP sent to NAPIMS for approval on 27th August
- 15th October 2010
  - Prior Notification for OML58 IPP was submitted to UNFCCC
- 16th November 2010
  - Approval from TOTAL's corporate management to review the OML-58 IPP and to authorize TEPNG to begin physical activity.

In November 2010, following an authorization from the JV partner NNPC, TOTAL Corporate management reviewed the technical parameters of the CCGT technology, and of the projected economics and authorized TEPNG (as operator of OML58) to sign the EWC, which represented the first major expenditure commitment ([redacted] US$ million). The EWC contract between TEPNG and the Contractor was subsequently signed on 31/12/2010.[38]

In addition to the [redacted] million US$ expenditure, the EWC confirmed the principal contractor and the technical design and costs of the CCGT, and recognized that the EWC was an integral part of the overall EPC contract for the facility.

[38] The initial value of the EPC was fully expended in 2011. While progression to the next construction phase is later than anticipated at end-2010, all the basic parameters of project scope, technical design, and cost remain valid,

The proposed project activity thus complies with the applicable requirements related to the prior consideration of the CDM outlined in the "Guidelines on the demonstration and assessment of prior consideration of the CDM" (version 04) with a start-date consistent with the CDM definition.

Summary of Additionality Assessment

Based on the assessment of additionality presented above, the proposed CDM project activity is deemed additional. The conclusions from the assessments undertaken in relation to the three required steps are summarized below:

Table 9: Summary of the demonstration of additionality

Step	Conclusion
1	The assessment done by applying Sub-steps 2b (Option III: Apply benchmark analysis), Sub-step 2c (Calculation and comparison of financial indicators), and 2d (Sensitivity Analysis) of the "Tool for the demonstration and assessment of additionality" version 07.0.0 consistently supports (for a realistic range of assumptions) the conclusion that the project activity is unlikely to be financially/economically attractive.
2	The analysis done by applying Step 4 (Common Practice Analysis) with the "Tool for demonstration and assessment of additionality" version 07.0.0 demonstrates that the project activity is not common practice in the relevant country and sector.
3	CDM registration has served to prioritize the project with the project participants, and the revenue for CERs contributes to improving the investment return, and importantly assures a stable cash flow.

B.6. Emission reductions

B.6.1. Explanation of methodological choices

The project activity is developed in line with the approved methodology AM0029 version 03. It requires the calculation of the following:

- Project emissions
- Baseline emissions
- Leakage emissions

Step 1: Project emissions

The project activity is on-site combustion of natural gas to generate electricity without auxiliary fuels in project operation[39]. The CO_2 emissions from electricity generation (PE_y) are calculated as follows:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y}$$

$PE_y =$	Is the total project emissions in the year(s) y
$FC_{f,y} =$	Is the total volume of natural gas or other fuel (f) combusted in the project plant or other start up fuel (m^3 or similar) in year(s) y

[39] If the IPP shuts down totally, disconnected from the grid and without power on site for essential equipment, a back-up diesel generator is used to restart the power plant (a 'black start'). However, this is not a normal part of the on-going operations of the power plant and is insignificant in its impact of ERs, and is therefore not considered in the ER estimates in the PDD. (Albeit diesel use is monitored and would be included, if used, in the actuals during verification.)

$COEF_{f,y}$ = Is the CO_2 emission coefficient (tCO_2/m^3 or similar) in year(s) for each fuel and is obtained as: $COEF_{f,y} = \sum NCV_y * EF_{CO2,f,y} * OXID_f$

Where:

$NCV_{f,y}$ = Is the net calorific value (energy content) per volume unit of natural gas or other fuel (f) in year y (GJ/m3) as determined from the fuel supplier, wherever possible, otherwise from local or national data

$EF_{CO2,f,y}$ = Is the CO2 emission factor per unit of energy of natural gas or other fuel (f) in year y (tCO2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data

$OXID_f$ = Is the oxidation factor of natural gas or other fuel (f).

In the PDD, the $NCV_{f,y}$ and $EF_{CO2,f,y}$ for gas are based on the gas composition as stated in the Project Statement of Requirement (SOR). This will be measured when the project activity starts using the sample taken from the gas supply by the gas processing facility. The $OXID_f$ is taken from the I standard. (Diesel fuel variables are IPCC standards.)

Step 2: Baseline emissions

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

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y}$$

According to the selected methodology AM0029 (version 03), the $EF_{BL,CO2,y}$ should be the lowest emission factor among the following three options:

Option 1 The build margin, calculated according to “Tool to calculate emission factor for an electricity system”; and

Option 2 The combined margin, calculated according to “Tool to calculate emission factor for an electricity system”, using a 50/50 OM/BM weight;

Option 3 The emission factor of the technology (and fuel) identified as the most likely baseline scenario under “Identification of the baseline scenario” above, and calculated as follows:

$$EF_{BL,CO2}(t_{CO2}/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh$$

Where:

$COEF_{BL}$: = The fuel emission coefficient (tCO2e/GJ), based on national average fuel data, if available, otherwise IPCC defaults can be used

η_{BL}: = The energy efficiency of the technology, as estimated in the baseline scenario analysis above

The electrical sector in Nigeria is currently undergoing a major restructuring and data collection is not yet fully centralized. The project participants have assembled the available data from public sources. Data for electricity to the grid is provided by Transmission Company of Nigeria for all relevant plants as well as data for gas consumed by all plants owned by the Federal Government. Where gas consumption data is not now available for the remaining relevant power plants, the gas consumption is calculated using the IPCC standards. The step-by-step calculation of the three options is done in a separate spread-sheet model. The results of this model show:

	Unit	Value	Description
$EF_{grid,BM,y}$	tCO_2/MWh	0.55	Emission factor of the grid based on the built margin
$EF_{grid,CM,y}$	tCO_2/MWh	0.55	Emission factor of the grid based on the combined margin
$EF_{BL,CO2}$	tCO_2/MWh	0.64	Emission factor of the grid based on the technology

Based on this analysis the build and operating margins are equivalent in having the lowest EF at 0.55; and this is the number that is used for calculation purposes in this PDD.

It should be clearly noted that data is currently being collected so as to replace the IPCC proxies with actual data, the result will almost certainly be to increase the emission factors for options 1 and 2. This means that the CERs calculated in this PDD will be lower than when they are calculated on an *ex post* basis with actual data. The available public statistics are being continuely improved due to NERC and NBET's efforts and great robustness is expected in the future, which is a primary reason for chosing *ex post*.

Leakage emissions

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring.

According to AM0029 version 03, the following leakage emission sources shall be considered:

- Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity;
- In the case LNG is used in the project plant: CO_2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \quad \textbf{(1)}$$

Where:

LE_{y} :	=	Leakage emissions during the year *y* in tCO_2e
$LE_{CH4,y}$:	=	Leakage emissions due to fugitive upstream CH_4 emissions in the year *y* in t CO_2e
$LE_{LNG,CO2,y}$:	=	Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year *y* in t CO_2e

Fugitive methane emissions

The net impact on fugitive methane emissions is determined in accordance with the methodology as follows:

$$LE_{CH4,y} = \left\lfloor FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4} \right\rfloor \cdot GWP_{CH4} \quad \textbf{(2)}$$

Where:

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

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL,upstream,CH4}$) is calculated consistent with the baseline emission factor ($EF_{BL,CO2}$) used in the calculation of baseline emissions. The baseline emission factor applied is equivalent to the Build Margin for this project. The leakage effect has thus been determined based on data for the cohort of power plants included in the Build Margin[40] (i.e. applying Option 1 in the methodology) as follows:

Option 1: Build Margin:

$$EF_{BL,upstream,CH4} = \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j}$$

Where:

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

Applying the relevant values for FF and EG, i.e. those already determined through the application of "Tool to calculate emission factor for an electricity system", the emission factor for upstream fugitive methane emissions occurring in the absence of the project activity is calculated to be 0.002 tCH4 per MWh electricity generation in the project plant (full calculation has been provided to the validating DOE).

[40] When $EF_{BL,upstream,CH4}$ is determined based on the build margin, the calculation should be consistent with the calculation of CO2 emissions in the build margin, i.e. *"the same cohort of plants and data on fuel combustion and electricity generation should be used, and the values for FF and EG should be those already determined through the application of "Tool to calculate emission factor for an electricity system""*.

Reliable and accurate national data on fugitive CH_4 emissions associated with the production, transportation and distribution of natural gas is not available for Nigeria. As per the guidance of the methodology, the applicable default value provided in Table 2 in the methodology has thus been applied. All plants included in the Build Margin combust natural gas. As a result, the value provided for natural gas (“Other oil exporting countries / rest of world” – “Total”) in Table 2 of the methodology has been applied (i.e. 296 tCH_4/PJ). All upstream emissions associated with consumption of natural gas in Nigeria occur outside of Annex I countries that have ratified the Kyoto Protocol.

Applying the average annual quantity of natural gas combusted in the project plant and the average annual electricity generation of the project plant during the period 2016-2025 (i.e. 10 years), the net fugitive methane emissions attributable to the project activity has been calculated according to Equation 5 in the methodology as follows:

$$LE_{CH4,y} = \left[433{,}098{,}827 \cdot 0.0396 \cdot 2.96 \cdot 10^{-4} - 2{,}243{,}200 \cdot 0.002\right] \cdot 21 = -4{,}470 \qquad \textbf{(3)}$$

CO_2 emissions from LNG

CO_2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) shall be considered in the case LNG is used in the project plant. This is not the case for the proposed CDM project activity, thus:

$$LE_{LNG,CO2,y} = FC_y \cdot EF_{CO2,upstream,LNG} = 0$$

Where:

$LE_{LNG,CO2,y}$:	=	Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year *y* in t CO_2e
FC_y:	=	Quantity of natural gas combusted in the project plant during the year *y* in m³
$EF_{CO2,upstream,LNG}$:	=	Emission factor for upstream CO_2 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system

Based on the above consideration, the net leakage effects (i.e. LE_y) are calculated to be -4,470 tCO_{2e}/yr. As total net leakage effects are negative ($LE_y < 0$), the project participants have as a conservative assumption set $LE_y = 0$ as per the requirements of the methodology. (The calculation is provided to the DOE.)

As the project plant will consume less natural gas than the cohort of power plants that would be used to generate the same amount of electric power in absence of the project, the project will not contribute to any constraints in supply of natural gas in the rest of the Nigerian economy. As is described in Section B.2, natural gas is abundant in Nigeria and reserves far exceed domestic demand needs. Therefore the gas used in the project will not displace gas used elsewhere in the economy, and will thus not lead to any leakage beyond what is already taken into account.

As natural gas is abundant in Nigeria and reserves far exceed domestic demand needs. Therefore the gas used in the project will not displace gas used elsewhere in the economy, and will thus not lead to any leakage.

Emission Reductions

To calculate the emission reductions the project participant shall apply the following equation:

$$ER_y = BE_y - PE_y - LE_y$$

Where:

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

B.6.2. Data and parameters fixed ex ante

Data / Parameter	$FC_{i,m,y}$
Unit	MSCF
Description	Amount of fossil fuel type *i* consumed by power plant / unit *m*, *k* or *n* (or in the project electricity system
Source of data	Annual Technical report published by National Control Centre, PHCN, Nigeria
Value(s) applied	(see table below)
Choice of data or Measurement methods and procedures	Not applicable
Purpose of data	For emission factor calculations
Additional comment	The fuel consumed in privately owned IPPs (Okpai, Afam6, Ibom, Omoku and Trans Amadi) are all estimated as their figures are not captured in the Annual Technical report published by National Control Centre, PHCN, Nigeria as at the time of validation of the project.

$FC_{i,m,y}$ (MMSCF)				
i	m	y		
		2009	2010	2011
Hydro	Kainji	N/A		
	Jebba			
	Shiroro			
Gas	Egbin	23,541	58,357	71,048
	Sapele	1,403	5,766	7,770
	Afam	2,275	967	4,565
	Delta	21,928	22,098	16,613
	AES	21,946	20,064	20,210
	Okpai	17,002	17,847	16,489
	Afam6	11,755	16,162	18,174
	Omotosho	4,279	4,478	4,390
	Geregu	5,071	11,810	20,148
	Ibom	27	2,222	2,655
	Omoku	3,542	1,821	1,186
	Trans Amadi	401	631	1,242
	Olorunsogo	940	3,139	3,351
	Olorunsogo II			9,175

Data / Parameter	$NCV_{i,y}$
Unit	TJ/ktonnes
Description	Net calorific value (energy content) of fossil fuel type *i* in year *y*
Source of data	IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories (48 TJ/Gg)
Value(s) applied	48.00
Choice of data or Measurement methods and procedures	None
Purpose of data	For emission factor calculations
Additional comment	

Data / Parameter	$EF_{CO2,i,y}$ and $EF_{CO2,m,i,y}$
Unit	tCO2/GJ
Description	CO_2 emission factor of fossil fuel type *i* used in power unit *m* in year *y*
Source of data	IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories (56100 kg/TJ)
Value(s) applied	0.0561
Choice of data or Measurement methods and procedures	None
Purpose of data	For emission factor calculations
Additional comment	

Data / Parameter	$EG_{m,y}$
Unit	MWh
Description	Net electricity generated by power plant/unit m, k or n (or in the project electricity system in case of EG_y) in year y or hour h
Source of data	Annual Technical report published by National Control Centre, PHCN, Nigeria
Value(s) applied	(see table below)
Choice of data or Measurement methods and procedures	Not applicable
Purpose of data	For emission factor calculations
Additional comment	

$EG_{m,y}$ (MWh)				
i	*m*	*y*		
		2009	2010	2011
Hydro	Kainji	2,505,663	2,300,991	1,716,259
	Jebba	2,676,860	2,693,741	2,567,337
	Shiroro	2,282,117	2,421,116	2,373,993
Gas	Egbin	3,383,990	5,385,476	6,752,678
	Sapele	121,269	513,637	664,312
	Afam	151,048	56,223	391,277
	Delta	1,591,573	1,957,869	1,488,119
	AES	1,681,451	1,538,651	1,557,067
	Okpai	3,079,384	3,232,402	2,986,405
	Afam6	2,129,059	2,927,275	3,291,651
	Omotosho	383,266	388,558	372,000
	Geregu	378,603	776,765	1,707,922
	Ibom	3,204	264,932	316,538
	Omoku	422,355	217,145	141,375
	Trans Amadi	47,768	75,220	148,079
	Olorunsogo	103,591	270,296	316,099
	Olorunsogo II			837,936

Data / Parameter	$\eta_{m,y}$ and $\eta_{k,y}$
Unit	-
Description	Average net energy conversion efficiency of power unit *m* or *k* in year *y*
Source of data	Default values provided in the Annex 1 tables of "*Tool to calculate the emission factor for an electricity system*" version 02.
Value(s) applied	Efficiency of Open Cycle after 2000: 0.395 Efficiency of Combined Cycle after 2000: 0.600
Choice of data or Measurement methods and procedures	None
Purpose of data	For emission factor calculations
Additional comment	
Data / Parameter	$OXID_f$
Unit	-
Description	Oxidation factor of natural gas used in the calculation of project emissions.
Source of data	IPCC, 2006
Value(s) applied	1
Choice of data or Measurement methods and procedures	-
Purpose of data	Calculation of project emissions
Additional comment	-

Data / Parameter	η_{BL}
Unit	%
Description	Energy efficiency of the technology, as estimated in the baseline scenario analysis i.e. gas-fired OCGT power generation
Source of data	Country data (MYTO, 2012)
Value(s) applied	32%
Choice of data or Measurement methods and procedures	The gas-fired OCGT power generation efficiency in the MYTO shall be used for estimation
Purpose of data	Calculation of baseline emissions
Additional comment	-

B.6.3. Ex-ante calculation of emission reductions
>>
Listed below are the ex-ante calculations to be used during the crediting period with relevant equations.
Project emissions:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y}$$

Baseline emissions:

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y}$$

Emissions reduction:

$$ER_y = BE_y - PE_y - LE_y$$

B.6.4. Summary of ex ante estimates of emission reductions

Year	Baseline emissions ($t\ CO_2e$)	Project emissions ($t\ CO_2e$)	Leakage ($t\ CO_2e$)	Emission reductions ($t\ CO_2e$)
17% of 2015	212,023	163,930	-	48,093
2016	1,272,135	983,579	-	288,556
2017	1,220,260	962,725	-	257,535
2018	1,260,545	989,459	-	271,085
2019	1,247,682	984,360	-	263,322
2020	1,213,970	959,722	-	254,249
2021	1,254,113	989,434	-	264,680
2022	1,241,251	974,315	-	266,936
2023	1,207,680	957,687	-	249,994
2024	1,247,682	979,363	-	268,319
83% of 2025	1,029,016	811,843	-	217,173
Total	12,406,358	9,756,416	-	2,649,942
Total number of crediting years	10 years			
Annual average over the crediting period	1,240,636	975,642	-	264,994

The actual emission reductions are expected to be higher due to the fact that the grid emission factor is being calculated on ex-post basis.

B.7. Monitoring Plan

B.7.1. Data and parameters to be monitored
(Copy this table for each piece of data and parameter.)

<table>
<tr><td>Data / Parameter</td><td>$FC_{gas,y}$</td></tr>
<tr><td>Unit</td><td>m^3</td></tr>
<tr><td>Description</td><td>Annual quantity of natural gas consumed in project activity</td></tr>
<tr><td>Source of data</td><td>Fuel flow meter at the project boundary</td></tr>
<tr><td>Value(s) applied</td><td>
<table>
<tr><td></td><td></td><td>4Q- 2015</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td><td>2021</td><td>2022</td><td>2023</td><td>2024</td><td>(1-3Q) - 2025</td></tr>
<tr><td>$FC_{gas,y}$</td><td>m3</td><td>72,918,161</td><td>442,370,178</td><td>428,232,984</td><td>440,124,644</td><td>437,856,197</td><td>426,896,815</td><td>440,113,188</td><td>433,388,043</td><td>425,991,638</td><td>435,633,577</td><td>433,342,216</td></tr>
</table>
</td></tr>
<tr><td>Measurement methods and procedures</td><td>Daily meter readings.</td></tr>
<tr><td>Monitoring frequency</td><td>Daily</td></tr>
<tr><td>QA/QC procedures</td><td>The meters will be subjected to regular maintenance based on international best practice and calibrations to ensure accuracy.</td></tr>
<tr><td>Purpose of data</td><td>To calculate project emissions</td></tr>
<tr><td>Additional comment</td><td>The total fuel consumption will be monitored both at supplier (gas plant) and project end for cross-verification</td></tr>
</table>

Data / Parameter	$FC_{diesel,y}$
Unit	m^3
Description	Annual quantity of diesel consumed in the diesel generator to start the power plant if and whenever it is used
Source of data	Flow meter at the diesel tank
Value(s) applied	zero
Measurement methods and procedures	Daily meter readings when used
Monitoring frequency	Daily whenever it is used
QA/QC procedures	The meters will be subjected to regular maintenance based on international best practice and calibrations to ensure accuracy.
Purpose of data	To calculate project emissions.
Additional comment	The fuel is not going to be used regularly but whenever it is used, the readings shall be taken and logged.

Data / Parameter	$NCV_{gas,y}$
Unit	GJ/m^3
Description	Net Calorific Value of the natural gas
Source of data	On-site chromatograph
Value(s) applied	0.0396 GJ/m^3
Measurement methods and procedures	The samples shall be analysed at the on-site chromatograph at least every two weeks
Monitoring frequency	At least every two weeks
QA/QC procedures	Sampling shall be carried out in accordance with applicable standards
Purpose of data	To calculate the project emissions
Additional comment	

Data / Parameter	$NCV_{diesel,y}$
Unit	GJ/m^3
Description	Net Calorific Value of the Diesel
Source of data	2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 Energy, default net calorific value for diesel provided in Table 1.2 in Chapter 1 (43.0 TJ/Gg)
Value(s) applied	0.04GJ/m^3
Measurement methods and procedures	-
Monitoring frequency	-
QA/QC procedures	Not applicable
Purpose of data	To calculate the project emissions
Additional comment	Please note that the IPCC value was converted from TJ/Gg to GJ/m^3 by applying the density of gas (0.87kg/m^3) as obtained from http://www.unep.org/transport/pcfv/pdf/Togo-SulphurinNIGERIA.pdf

Data / Parameter	$EF_{CO2,gas,y}$
Unit	tCO_2/GJ
Description	Emission factor of natural gas.
Source of data	Calculated.
Value(s) applied	0.0567 tCO_2/GJ
Measurement methods and procedures	Measurement based on analysis of gas sample taken prior to the project activity.
Monitoring frequency	At least annually
QA/QC procedures	-
Purpose of data	To calculate the project emissions
Additional comment	-

Data / Parameter	$EF_{CO2,diesel,y}$
Unit	tCO_2/GJ
Description	Emission factor of Diesel.
Source of data	2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 Energy, default emission factor for gas/diesel oil provided in Table 2.2 in Chapter 2 (74.1 tCO2/TJ)
Value(s) applied	0.0741 tCO_2/ GJ
Measurement methods and procedures	-
Monitoring frequency	Annually
QA/QC procedures	Not applicable
Purpose of data	To calculate the project emissions
Additional comment	-

<table>
<tr><td>Data / Parameter</td><td>$EG_{PJ,y}$</td></tr>
<tr><td>Unit</td><td>MWh.</td></tr>
<tr><td>Description</td><td>Electricity supplied to the grid.</td></tr>
<tr><td>Source of data</td><td>Electricity meters installed in the plant power export point to bus-bar.</td></tr>
<tr><td>Value(s) applied</td><td>
<table>
<tr><td></td><td></td><td>4Q-2015</td><td>2016</td><td>2017</td><td>2018</td><td>2019</td><td>2020</td><td>2021</td><td>2022</td><td>2023</td><td>2024</td><td>(1-3Q)-2025</td></tr>
<tr><td>$EG_{PJ,y}$</td><td>MWh</td><td>383,557</td><td>2,326,910</td><td>2,207,496</td><td>2,280,372</td><td>2,257,103</td><td>2,196,117</td><td>2,268,737</td><td>2,245,468</td><td>2,184,738</td><td>2,257,103</td><td>2,233,834</td></tr>
</table>
</td></tr>
<tr><td>Measurement methods and procedures</td><td>Continuous metering of the electricity supplied to the grid</td></tr>
<tr><td>Monitoring frequency</td><td>Continuous</td></tr>
<tr><td>QA/QC procedures</td><td>Electricity generated recorded at the plant to be compared with what is delivered to PHCN.</td></tr>
<tr><td>Purpose of data</td><td>To calculate project emissions</td></tr>
<tr><td>Additional comment</td><td>-</td></tr>
</table>

<table>
<tr><td>Data / Parameter</td><td>$EF_{CM,y}$</td></tr>
<tr><td>Unit</td><td>tCO2/MWh</td></tr>
<tr><td>Description</td><td>The combined margin of the emission factor of the Nigerian grid</td></tr>
<tr><td>Source of data</td><td>Calculated as the weighted average of the build margin emission factor and operating margin emission factor (with 50/50 weights to OM and BM) as per “Tool to calculate emission factor for an electricity system vers. 02”</td></tr>
<tr><td>Value(s) applied</td><td>0.55</td></tr>
<tr><td>Measurement and procedures</td><td>The values are taken from the electricity data in the Annual Technical report published by National Control Centre, PHCN, Nigeria
Authority.</td></tr>
<tr><td>Monitoring frequency</td><td>Annually</td></tr>
<tr><td>QA/QC Procedure</td><td>Not applicable</td></tr>
<tr><td>Purpose of data</td><td>For emission factor calculations</td></tr>
<tr><td>Additional comment</td><td>
<table>
<tr><td>BM</td><td>0.55</td></tr>
<tr><td>OM</td><td>0.55</td></tr>
</table>
The value is used only for estimate now and will be monitored ex-post throughout the crediting period.</td></tr>
</table>

Data / Parameter	$EF_{BM,y}$
Unit	tCO2/MWh
Description	The build margin of the emission factor of the Nigerian grid
Source of data	Calculated as per the "*Tool to calculate emission factor for an electricity system vers. 02*"
Value(s) applied	0.55
Measurement methods and procedures	The values are taken from the electricity data in the Annual Technical report published by National Control Centre, PHCN, Nigeria Authority.
Monitoring Frequency	Annually
QA/QC Procedure	Not applicable
Purpose of data	For emission factor calculations
Additional comment	The value is used only for estimate now and will be monitored ex-post throughout the crediting period.

Data / Parameter	$EF_{OM,y}$
Unit	tCO2/MWh
Description	The operating margin of the emission factor of the Nigerian grid
Source of data	Calculated as per the "*Tool to calculate emission factor for an electricity system vers. 02*"
Value(s) applied	0.55
Measurement methods and procedures	The values are taken from the electricity data in the Annual Technical report published by National Control Centre, PHCN, Nigeria Authority.
Monitoring frequency	Annually
QA/QC Procedure	Not applicable
Purpose of data	For emission factor calculations
Additional comment	The value is used only for estimate now and will be monitored ex-post throughout the crediting period.

Data / Parameter	LE
Unit	tCO_2
Description	Leakage due to the project activity
Source of data	Calculated
Value(s) applied	0
Measurement methods and procedures	Calculated as per equation 5 of the methodology
Monitoring frequency	Annually
QA/QC procedure	As applied in $FC_{gas,y}$ and $EG_{PJ,y}$
Purpose of data	Calculation of leakage emissions
Additional comment	The project will not contribute to any constraints in supply of natural gas in the rest of the Nigerian economy as demonstrated in section B6.1. However, the Fuel consumption and the electricity generated by the project activity will be monitored all through the crediting period in accordance with the relevant parameters.

B.7.2. Sampling plan

The inlet gas composition will be analysed by an on-site gas chromatograph. It will be done on a regular basis at a frequency of at least once every two weeks.

B.7.3. Other elements of monitoring plan

All data to be monitored (readings, calibrations, etc.) will be collected and stored (electronic, paper, etc.) as recommended by the approved methodology. All measurements will be conducted with calibrated measurement equipment according to relevant industry standards. Procedures necessary for the proper maintenance of the project will be stated in the procedures manual.

The monitored data will be used to prepare the monitoring reports when due. The data will be stored until 2 years after the end of the crediting period or the last issuance of CERs whichever occurs later.

The on-site CDM focal point at the IPP will have primary responsibility for the data collection and archiving. There will be QA/QC at TEPNG operational headquarters (currently located in Port Harcourt.)

SECTION C. Duration and crediting period
Duration of project activity
C.1.1. Start date of project activity

The start date of the project activity is 31/12/2010, which is the signing the first major expenditure contract ($[redacted] million).

C.1.2. Expected operational lifetime of project activity
>>
20 years

Crediting period of project activity
C.1.3. Type of crediting period

10 years (fixed).

C.1.4. Start date of crediting period

01/11/2015 (The OCGT starts operation in 2015 but the CCGT, and thus the project activity is expected to begin on this date)

C.1.5. Length of crediting period

10 years.

SECTION D. Environmental impacts

D.1. Analysis of environmental impacts

In compliance with statutory regulatory requirements (EIA Act No. 86 of 1992, and DPR EGASPIN of 1991, revised 2002) to provide an effective Environmental Management Monitoring Plan, ELF Petroleum Nigeria Limited (EPNL)[41] commissioned Harmonix Engineering and Environmental Services Limited to carry out an Environmental Impact Assessment (EIA) studies for the proposed IPP project. Elf Petroleum Nigeria Limited (EPNL) (now Total E&P Nigeria Limited, TEPNG) is the operator of the NNPC/EPNL joint venture.

D.2. Environmental impact assessment

A detailed Environmental Impact Assessment of the project activity was carried out in line with the national regulatory requirements and the organization's corporate policy. The study assessed the potential impact the project activity will have on the people and the environment. The report also presents several mitigation steps to be taken to minimise the adverse impact of the environment and the people throughout the life of the project.

An environmental management plan-EMP (Chapter 7 of the EIA) has been drawn up to ensure that all mitigation steps listed in the EIA are adhered to so that negative impacts of the project activity are minimised.

Below is a summary of the potential impacts and the mitigation measures to be put in place.

[41] The name of the company at that time was EPNL and it was later merged into TEPNG.

S/N	Potential Impacts	Mitigation measures
1	**<u>Mobilisation Phase</u>** • Accidents (loss of life) injuries, material damage, Lost Time Injury (LTI) • Alteration in air quality via vehicular emissions of CO_2 and other exhaust gases associated with automobile movement. • Interference with other road users. • Community crises	• EPNL shall ensure proper journey management and traffic plan; • EPNL shall maintain a good first aid unit and/ or clinic at base; • EPNL and its contractors shall ensure the use of low emission vehicles; • The transport department of EPNL shall adhere to the company's traffic policy; • EPNL shall finalize the MOU renegotiation with the local communities in order to stabilize their expectations; • EPNL shall provide sustainable social actions in order to teach people how to drive their development by themselves.
2	**<u>Preparation Phase</u>** • Accidents/Occupational Hazards • Loss of farmland, Vegetation cover and vegetal / solid waste • Loss of soil organic matter layer Run off (gully erosion) and Siltation of ponds. • Air pollution (Emission of CO and Dust) • Noise and vibration of machines • Fire outbreak	• EPNL shall operate Material Data Sheet / Safe Handling Of Chemicals (SHOC) Procedures • EPNL shall ensure the use of Material Certification/ Work Permit, PPE and effective sickbay at site / base • EPNL shall adhere to the use of relevant equipment for excavation / levelling • EPNL shall build temporary embankment around cleared areas to avoid run-off • EPNL shall sprinkle water to reduce dust pollution if construction is done during dry season • EPNL shall adopt the use of low noise equipment and machines

3	**Construction Phase** • Accidents/Occupational Hazards • Waste lubes and waste oils • Fire outbreak • Noise pollution • Solid waste litter • Large decrease of local activities	• EPNL shall consult and study material data sheet and SHOC for every equipment / chemical before handling • EPNL shall ensure that all lubes and waste oil are safely contained. • EPNL shall install fire extinguishers and alarms, fire fighting and warning equipment • EPNL shall use sound proof welding machines and generators • EPNL shall dispose all solid wastes at approved dumpsite • EPNL shall prepare local communities for the transition from construction phase to operation phase with reduced activities
4	**Operation and Maintenance Phase** • Accident / Occupational health hazards (injuries, material damage, respiratory/hearing problems • Permanent threshold of hearing (Noise pollution) • Fire outbreak • Waste/contaminated water • Contamination of ponds and adjacent environment • Alteration of air quality via CO_2, NOx, SOx, CO	• EPNL shall operate a First Aid or sick bay unit at site and a clinic at base • The use of material data sheet, SHOC and appropriate Personal Protective Equimpent procedures shall strictly be enforced • EPNL shall install fire extinguishers and alarms fire fighting and warning • EPNL shall treat waste water before discharge or safely contained for collection and discharge in line with the company Waste Management Procedures • Waste water should be safely contained and disposed in line with W.M.P. • EPNL shall use low gaseous emission ISO certified turbine machine and ensure routine monitoring of air quality
5	**Demobilisation and Decommissioning** • Noise pollution • Discharge of spent lubes and waste oil • Accident • Solid waste generation • Fire outbreak • Air pollution • Discharge of sewage	• EPNL shall use low noise machines during demolition • EPNL shall safely contain all liquid waste for treatment and discharge • EPNL shall as much as is practicable return the land to near its original state after decommissioning for alternative purpose • EPNL shall install fire extinguishers and alarms fire fighting and warning

SECTION E. Local stakeholder consultation

E.1. Solicitation of comments from local stakeholders

Present in the area since 1964, TEPNG has a long-standing relationship with its host communities in OML58. Since 2004, this relationship has been defined by agreements (MoUs) that dictate the specific areas of intervention for TEPNG's sustainable development policy. These areas include: employment, skills acquisition, micro-credit, scholarships and so-called "development envelopes". These five pillars form the basis of all agreements with host communities, the size of which vary depending on the presence TEPNG has in the local area.

Of all of the currently valid agreements, the two largest ones both concern Egi Clan, the host community to the Obagi GRA and the Obite Gas Plant, future site of the IPP project. The first is an agreement with the entire Egi Clan itself (16 communities) whilst the second concerns on "Oil and Gas Producing Families and Communities", a stakeholder group that represents the families and communities that are directly impacted by our installations, and who are therefore considered producing. Through these two agreements, TEPNG will amongst other objectives previously cited invest over 27 million dollars over in development projects for its host communities over the next 5 years. To implement these agreements, TEPNG and its stakeholders have created "Steering" and "Implementation" Committees that will govern and supervise the investments, scholarship and skill acquisition distributions, as well as ensure that the employment quotas as defined in the agreements are respected, amongst other things. To guarantee efficiency it has been agreed that the Steering Committees, which serve as an executive board of sorts, shall meet on a quarterly basis, whereas the Implementation Committees, which are responsible for the groundwork, meet monthly. This approach ties in to the already established TEPNG policy of the maintaining of frequent communication with its stakeholders in order to guarantee the efficient implementation of its sustainable development policies.

TEPNG has assured that the EIA incorporated climate impacts and specifically those related to the CO_2 emissions of both an OCGT and a CCGT facility. In the approved EIA "EPNL INDEPENDENT POWER PLANT (IPP) ENVIRONMENTAL IMPACT ASSESSMENT (EIA) November 2007" a specific section of the report addresses the climate change implications and including that of the OCGT and CCGT options. Also the Socio-Economic Survey asked questions of the community about impacts that can be caused by climate change (such as whether harvests and fishing yields had been increasing or decreasing or the last five years.) These issues were discussed in public consultations held as part of the EIA.

In the community meeting held at Ogbogu Primary School 27/01/06, the IPP and the environmental impacts were discussed and comments received. Stakeholder's present at the forum included:

- Regulators (Department of Public Resources, Federal Ministry of Environment, Rivera State Ministry of Environment)
- Community Organizations (Egi People's Forum, Egi Women Welfare Association, Egi Oil and Gas Production Association, Egi Youth Federation)
- Others (Family landlords and other community members)

In the public forum "Panel Meeting" held on 20/06/07 at the Presidential Hotel in Port Harcourt, the project was presented to both government and community stakeholders. In the formal presentation, the issues of CO_2 emissions from OCGT and CCGT were included.

These meetings were in open forum where all participants were encouraged to make comments.

It should be noted that this is one of on-going meetings to keep the community informed of the IPP and its environmental impacts.

E.2. Summary of comments received
>>
Comments received related primarily to the economic benefits (or the lack there of) to the community either in the past or in the future from the project's construction and operation. Youth employment, payments of compensation and engagement of contractors from the community were issues identified as related to perceived negative local economic impacts on the community.

One participant from the EGI Women's Forum at the Ogbogo meeting did lament the "declining harvest" which she believed was due to "environmental" causes.

E.3. Report on consideration of comments received

The comments are summarized in the EIA. The JV has a MoU with the communities and the considerations brought up in these and any subsequent, on-going meetings are addressed via a MoU on a regular basis.

SECTION F. Approval and authorization
>>

Environmental Impact Assessment Certificate

FMENV/EIA/ 000235

FEDERAL MINISTRY OF ENVIRONMENT
ENVIRONMENTAL IMPACT STATEMENT
&
Certificate

1. Project Identity: OML - 58 INDEPENDENT POWER PLANT PROJECT
2. Proposed date of project commencement: 1st August, 2007
3. Project Proponent: ELF PETROLEUM NIGERIA LIMITED
4. Project Location: OGBA/EGBEMA/NDONI LOCAL GOVERNMENT AREA

COMMENTS: (i) There shall be continuous consultation with the project's host communities throughout the life span of the project. (ii) There shall be Impact Mitigation Monitoring of the project by the Ministry in collaboration with other relevant regulagory Agencies (iii) There be strict adherence to the mitigation measures and full implementation of the EMP for the project.

5. CERTIFICATION: The Federal Ministry of Environment by the power conferred on it by section 42 of EIA Act No. 86 of 1992 hereby certifies that OML - 58 INDEPENDENT POWER PLANT Project as proposed may proceed subject to above comments.

Date of Issue: 10th April, 2008 Expiry Date: 10th April, 2013

Sign: Permanent Secretary

Date: 30/04/08

Seal of the Ministry

NOTE: Federal Ministry of Environment shall not be liable to any claim(s) under this permit.

- - - - -

Appendix 1: Contact information of project participants

Organization name	Nigerian National Petroleum Corporation
Street/P.O.Box	Herbert Macaulay Way, Central Business District,
Building	NNPC House
City	Abuja
State/Region	Federal Capital Territory
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Country	Nigeria
Telephone	+234 9 460 82659
Fax	
E-mail	Bernard.Agube@NNPCGroup.com
Website	www.nnpcgroup.com
Contact person	Bernard Agube
Title	CDM Coordinator, RED Division
Salutation	Mr
Last name	Agube
Middle name	
First name	Bernard
Department	
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Direct fax	
Direct tel.	+234 9 460 82659
Personal e-mail	Bernard.Agube@NNPCGroup.com

Organization name	Total E&P Nigeria Limited
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State/Region	Federal Capital Territory
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Fax	
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Website	www.total.com
Contact person	Paul Abbott
Title	IPP Asset Commercial Manager
Salutation	Mr
Last name	Abbott
Middle name	
First name	Paul
Department	
Mobile	
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State/Region	Federal Capital Territory
Postcode	
Country	Nigeria
Telephone	Tel: +234 (0) 9460 7072
Fax	
E-mail	moses.amadasun@total.com
Website	www.total.com
Contact person	Moses Amadasun
Title	Deputy General Manager, IPP
Salutation	Dr
Last name	Amadasun
Middle name	
First name	Moses
Department	
Mobile	
Direct fax	
Direct tel.	Tel: +234 (0) 8070172202
Personal e-mail	moses.amadasun@total.com

Appendix 2: Affirmation regarding public funding

There is no public funding for this project.

Appendix 3: Applicability of selected methodology

All information is provided in the main PDD document.

Appendix 4: Further background information on ex ante calculation of emission reductions

Calculation of the Grid Emission Factor (GEF) of the electricity grid in Nigeria according to the "Tool to calculate the emission factor for an electricity system" Version 04.0. The various steps are explained in this appendix. All data and calculations are contained in a separate spread-sheet available to the validators.

It should be stressed that Nigeria is restructuring its electrical sector and as such information on grid factors is not complete. Currently electricity to the grid is available for all connected power plants and fuel consumption for all Federal Government owned power plants. Five power plants are not federally owned and information on fuel consumption is not currently available. The calculations in this section use EF per power plant when fuel data is available, and when not available use IPCC standards to calculate the implicit fuel consumption. The developer is currently working with public entities to obtain the missing fuel data, and when available, the power plant EF will be updated and the grid EF recalculated.

STEP 1: Identify the relevant electricity systems

The DNA of the host country (Nigeria) has not published a delineation of the project electricity system and connected electricity systems; therefore, the project electricity system and any connected electricity system are defined here and their assumptions are justified and documented.

As a result of using the following criteria, no significant transmission constraints were found:

- The electricity systems do not have spot markets for electricity with differences in electricity prices (without transmission and distribution costs) of more than 5 percent between the systems during 60 percent or more of the hours of the year;
- The transmission line is not operated at 90% or more of its rated capacity during 90% percent or more of the hours of the year.

Since the application of these criteria does not result in a clear grid boundary, a national grid definition is used; in the case of Nigeria as large country with a single national dispatch system where all regions will be affected, directly or indirectly, by the CDM project activity.

Below, the geographical extent of the project electricity system is documented and all grid power plants/units connected to the system are identified.

There is no connected electricity system located partially or totally in Annex-I countries.

According to the tool, the reference system is the project electricity system. Hence electricity transfers from a connected electricity systems to the project electricity system are defined as electricity imports while electricity transfers from the project electricity system to connected electricity systems are defined as electricity exports. In the case of Nigeria, there are no electricity exports or imports.

For the purpose of determining the build margin emission factor, the spatial extent is limited to the project electricity system, since no recent or likely future additions to the transmission capacity shall enable any imported electricity.

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

Step 3: Select a method to determine the operating margin (OM)
With respect to the tool, the ***Option a*** (Simple OM) can be used since Low-cost/must-run (LC/MR) resources[42] constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production.

The relevant plant data and calculation are contained in a separate "EF" spread-sheet which is furnished to the validators.

As a result, it can be observed that the average contribution of LC/MR resources (i.e. hydroelectric power plants) is less than 50% of total grid generation, therefore Simple OM (option a) is used.

The emission factor is determined once at the validation stage, thus no monitoring and recalculation of the emissions factor during the crediting period is required.

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

The simple OM emission factor is calculated as the generation-weighted average CO_2 emissions per unit net electricity generation (tCO_2/MWh) of all generating power plants serving the system, not including low-cost/must-run power plants/units.

The simple OM is calculated by the following option:

Option A: Based on the net electricity generation and a CO_2 emission factor of each power unit; or
Option B: Based on the total net electricity generation of all power plants serving the system and the fuel types and total fuel consumption of the project electricity system.

For this project and with respect to the tool, **Option B** is used since:

(a) The necessary data for Option A is not available; (b) Only nuclear and renewable power generation are considered as low-cost/must-run power sources and the quantity of electricity supplied to the grid by these sources is known; and(c) Off-grid power plants are not included in the calculation (i.e. Option I has been chosen in Step 2).

[42] Low-cost/must-run resources are defined as power plants with low marginal generation costs or power plants that are dispatched independently of the daily or seasonal load of the grid. They typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation. If coal is obviously used as must-run, it should also be included in this list, i.e. excluded from the set of plants.

Option B - Calculation based on total fuel consumption and electricity generation of the system

Under this option, the simple OM emission factor is calculated based on the net electricity supplied to the grid by all power plants serving the system, not including low-cost/must-run power plants/units, and based on the fuel type(s) and total fuel consumption of the project electricity system, as follows:

$$EF_{grid,OMsimple,y} = \frac{\sum_i \left(FC_{i,y} \times NCV_{i,y} \times EF_{CO2,i,y}\right)}{EG_y}$$

Where:

$EF_{grid,OMsimple,y}$	= Simple operating margin CO_2 emission factor in year y (tCO_2/MWh)
$F_{Ci,y}$	= Amount of fossil fuel type *i* consumed in the project electricity system in year *y* (massor volume unit)
$NCV_{i,y}$	= Net calorific value (energy content) of fossil fuel type i in year y (GJ/mass or volumeunit)
$EF_{CO2,i,y}$	= 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 thesystem, 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 electricity system inyear *y*
y	= The relevant year as per the data vintage chosen in Step 3.

For this approach (simple OM) to calculate the operating margin, the subscript *m* refers to the power plants/units delivering electricity to the grid, not including low-cost/must-run power plants/units.

According to the Tool, if for a power unit m, only data on electricity generation and the fuel types used is available, the emission factor should be determined based on the CO_2 emission factor of the fuel type used and the efficiency of the power unit, as follows:

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \times 3.6}{\eta_{m,y}}$$

Where:

$EF_{EL,m,y}$	= CO_2emission factor of power unit m in year y (tCO_2/MWh)
$EF_{CO2,m,i,y}$	= Average CO_2emission factor of fuel type *i* used in power unit m in year y(tCO_2/GJ)
$\eta_{m,y}$	= Average net energy conversion efficiency of power unit m in year *y* (ratio)
m	= All power units serving the grid in year *y* except low-cost/must-run power units
y	= The relevant year as per the data vintage chosen in Step 3

All data and calculations are contained in a separate spread-sheet model furnished to the validators.

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

According to the tool, there are two options for vintage of data:

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

In the case of this project, the ***Option 1*** (ex-ante) has been used. As per this option monitoring the emission factor during the crediting period is not required.

Capacity additions from retrofits of power plants are not included in the calculation of the build margin emission factor, as per the tool.

According to the tool, the sample group of power units *m* used to calculate the build margin should be determined as per the following procedure, consistent with the data vintage selected above:
(a) Identify the set of five power units, excluding power units registered as CDM project activities,that started to supply electricity to the grid most recently ($SET_{5\text{-}units}$) and determine their annual electricity generation ($AEG_{SET\text{-}5\text{-}units}$, in MWh);

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

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As a result, the set of power units that started to supply electricity to the grid most recently and that comprise 20% of AEG_{total}.

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In the above table, $\boldsymbol{AEG_{SET\text{-}\geq 20\%}}$is the annual electricity generation of $\boldsymbol{SET \geq 20\%}$.

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

Identify the date when the power units in SET_{sample} started to supply electricity to the grid.
If non

e of the power units in SET_{sample} started to supply electricity to the grid more than 10 years ago, then use SET_{sample} to calculate the build margin. In this case ignore steps (d), (e) and (f).

After a comparison between the two sets of power units, $SET_{5\text{-}units}$ and $SET_{\geq 20\%}$, it is clear that $SET_{\geq 20\%}$ has a larger value and is therefore used as the sample. Hence, SET_{sample} and their corresponding year of commissioning.

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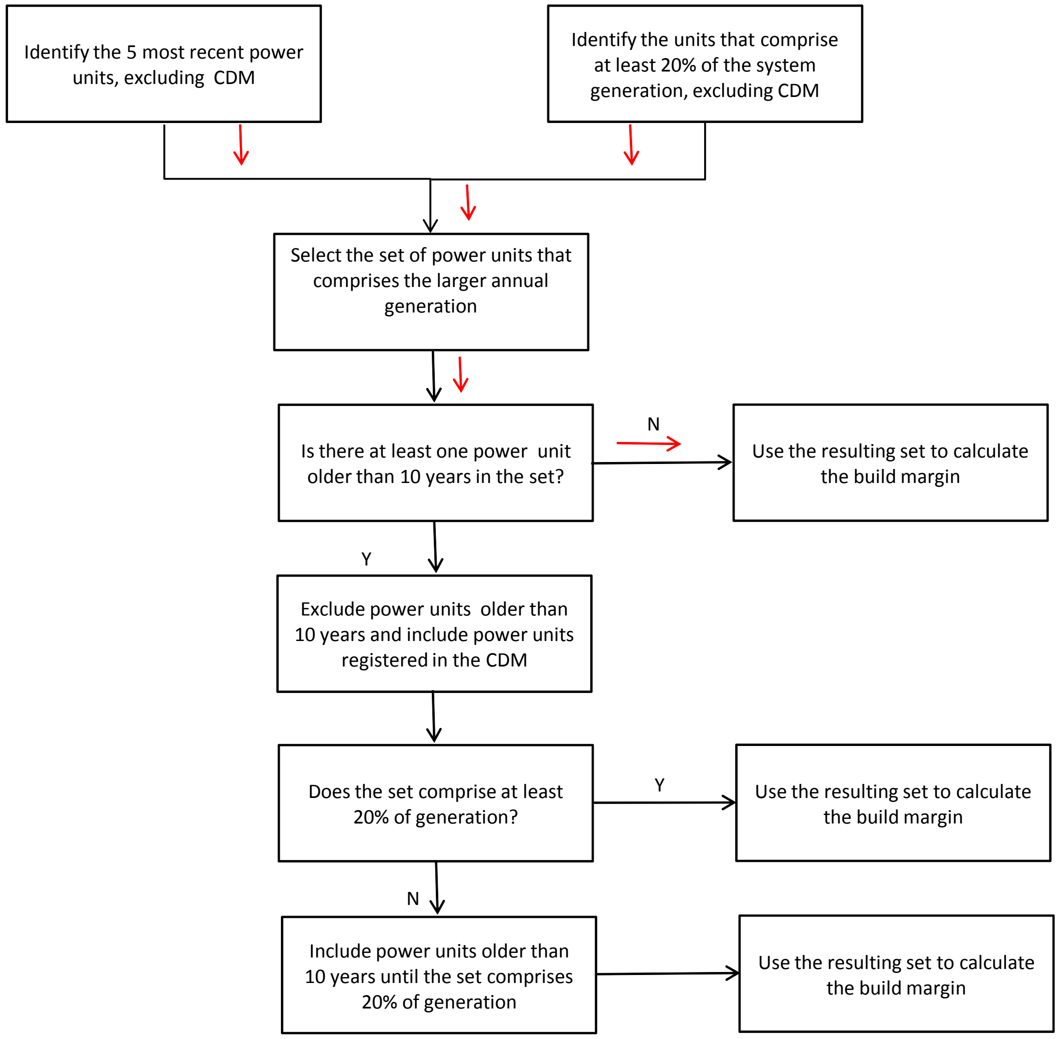
In order to summarize the above procedure, the below diagram as per the tool could be followed. The red arrows indicate the followed algorithm.



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

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

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 electricity generation data is available

The CO_2 emission factor of each power unit *m* ($EF_{EL,m,y}$) are determined as per the tool (guidance in Step 4 (a) for the simple OM), using options A1, A2 or A3, using for *y* the most recent historical year for which electricity generation data is available, and using for *m* the power units included in the build margin.

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Step 6 : Calculate the combined margin emissions factor

The calculation of the combined margin (CM) emission factor ($EF_{grid,CM,y}$) is based on one of the following methods:
(a) Weighted average CM; or
(b) Simplified CM.

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

(a) Weighted average CM

The combined margin emissions factor is calculated as follows:

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

Where:
$EF_{grid,BM,y}$= Build margin CO_2 emission factor in year y (tCO_2/MWh)
$EF_{grid,OM,y}$= Operating margin CO_2 emission factor in year y (tCO_2/MWh)
w_{OM} = Weighting of operating margin emissions factor (%)
w_{BM}= Weighting of build margin emissions factor (%)
As per the tool, the values of w_{OM} = 0.5 and w_{BM} = 0.5 are considered for the first crediting period.

All data and calculations are contained in a separate spread-sheet model furnished to the validators

Appendix 5: Further background information on monitoring plan

Appendix 6: Summary of post registration changes

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History of the document

Version	Date	Nature of revision
04.0	EB 66 13 March 2012	Revision required to ensure consistency with the "Guidelines for completing the project design document form for CDM project activities" (EB 66, Annex 8).
03	EB 25, Annex 15 26 July 2006	
02	EB 14, Annex 06 14 June 2004	
01	EB 05, Paragraph 12 03 August 2002	Initial adoption.
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